ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES IN THE CENTRAL VALLEY OF CALIFORNIA

Prepared for the California Regional Water Quality Control Board, Central Valley Region

May 2011
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Executive Summary
EXECUTIVE SUMMARY

Introduction

This publication is a compilation of three economic reports that examine the feasibility of constructing and operating dairy manure digesters and co-digesters in the Central Valley of California under 2010 conditions. The dairy industry in the Central Valley currently has about 1,400 dairies that house about 1.5 million milk cows and support stock. These dairies produce a substantial quantity of dairy manure that can be processed by anaerobic digesters to produce biogas, a flexible renewable source of energy that can be used to help achieve the 2010 and 2020 California Renewables Portfolio Standard. Dairy digesters are also a technology that can assist California in reducing greenhouse gas emissions in support of the California Global Warming Solutions Act of 2006 (also known as Assembly Bill or AB 32) by controlling the breakdown of manure in contained vessels that efficiently capture biogas, which has high concentrations of methane (a greenhouse gas).

The Technical Advisory Group (TAG) members provided input and comments on drafts of the three economic reports in writing and during four TAG meetings held in 2010 at the Central Valley Water Board’s Rancho Cordova office. The TAG included about 80 persons and was inclusive of the major stakeholders; including the dairy industry, digester developers, utility companies, environmental and environmental justice groups, and state and local agencies. Written comments by TAG members (Appendix A) on each of the three reports, which were released several months apart from one another, helped guide the effort and provide insight into diverse and at times conflicting points of view on the overall economic viability of dairy digesters and factors that influence the economic viability of dairy digesters. The three final reports are as follows:

- The Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report (the first report) reviews the current state of anaerobic digestion at dairies in California and the U.S. The report identifies the key technologies for conversion of manure to biogas and biogas to energy (electricity, heat, and biomethane), as well as the economic factors and regulatory policies that affect the financial feasibility of implementing the technologies.

- The Economic Feasibility Model Approach of Dairy Manure Digester and Co-Digester Facilities report (the second report) describes the economic model used to evaluate digester feasibility. The report outlines the four scenarios modeled and the basis for the assumptions used to populate the model. These assumptions include the technical performance of the digester systems as well as costs and economic assumptions.

1 A list of TAG members can be found at the end of the Executive Summary.
• The Economic Feasibility Model Findings for Dairy Manure Digester and Co-digester Facilities report (the third report) describes the outcome of the economic modeling of dairy digesters in California and evaluates the potential for improving financial feasibility through technical and regulatory means. The report compares the financial feasibility of small and large systems, with and without co-digestion of food waste, producing electricity or biomethane.

Summary of Findings

Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities

This first report contains a review of the state of technologies, markets, and regulations surrounding dairy digesters for biogas energy (electricity, heat, and biomethane) production as of 2010. The revenue, cost, and implementation factors pertinent to deployment of anaerobic digestion technologies in the dairy industry are reviewed, and the study finds that the following key factors contribute to economic viability of dairy manure digesters:

• Conventional energy prices
• Regulatory and legislative support
• Role of utilities
• Access to capital and third party developers
• Air quality regulation of on-site electrical generation
• Cost and minimum size for biogas upgrading
• Proximity to feedstocks and energy infrastructure
• Permitting
• Technological change

The review determines that current manure digesters produce low rates of biogas relative to the cost of construction and operation. Furthermore, the value of the biogas is currently tied to conventional energy prices, and the cost of converting biogas to electricity and biomethane with conventional technologies remains too high to compete with the low conventional energy prices. This difficulty is compounded by strict air quality regulations in the Central Valley that necessitate costly emissions reduction measures. Therefore, technological advances that reduce the cost of converting biogas to useful forms of energy in environmentally sustainable ways (or regulatory support that has this effect) will be important for the future success of anaerobic digesters. Additional regulatory mechanisms for improving dairy digester revenue streams and reducing costs are also discussed.
Economic Feasibility Model of Dairy Manure Digester and Co-Digester Facilities

This second report describes the development of a cash-flow model for determination of the Internal Rate of Return (IRR) on dairy digester projects. The financial model consists of the following components:

- System productivity assumptions
- Revenue projections
- Cost of production estimates
- Applicable financial parameters

Briefly, the system productivity is calculated from the literature on dairy manure production and conversion rates, assuming well-managed dairies collecting all of the available manure for treatment and moderately efficient conversion to biogas such as is typically achieved in mixed and heated digesters. Co-digestion of food waste with manure is considered. Energy conversion efficiencies, production of liquid and solid digestate, and reduction of greenhouse gas emissions relative to current manure management practices are also specified.

Revenue projections are developed based on the 2010 state of markets for biogas energy (for use both on-site and as a commodity), renewable energy, greenhouse gas reduction, solid digestate, liquid digestate, and waste treatment in the case of co-digestion. The costs of anaerobic digestion, biogas conversion (to both electricity and biomethane for pipeline gas injection), taxes, and debt financing are delineated. Finally, the key financial parameter necessary for calculating internal rate of return and evaluating financial feasibility are described and assumed for dairy digester projects. The inflation rate, debt ratio and debt interest rate, target internal rate of return, and tax rate and depreciation are defined and described for the project.

In addition to productivity, revenues, costs, and financing for general projects in this sector, four distinct system configurations are described for analysis utilizing the financial model. These four projects, defined in order to capture a range of different possible configurations at large and small dairies with a variety of access to utilities and co-digestion waste streams, were:

1. Farm-scale biogas production for on-site electrical generation
2. Pipeline injection scale biomethane production
3. Co-digestion of manure with available organic feedstocks
4. Centralized biomethane upgrade system with biogas transportation

Economic Feasibility Model Findings for Dairy Manure Digester and Co-digester Facilities

This last report (the third report) describes the results of the economic modeling of the four system configurations defined in the second report, Economic Feasibility Model of Dairy Manure Digester...
and Co-Digester Facilities. The itemized and total construction costs, annual expenses, and revenues are outlined for each configuration, along with the results which include:

- Required annual revenues for adequate profitability
- Annual surplus (shortage) compared to projected total annual revenues
- Cost of energy
- Current energy price shortfall
- Productivity increase required

The results of the modeling effort are summarized and compared in the following table.

### TABLE ES-1
**COMPARISON OF DIGESTER SYSTEMS ECONOMIC FEASIBILITY**

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<tr>
<td>System Characteristics</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Size</td>
<td>1,000 Cows</td>
<td>1,000 Cows</td>
<td>10,000 Cows</td>
<td>10,000 Cows</td>
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<tr>
<td>Facility</td>
<td>100 kW Generator</td>
<td>200 kW Generator</td>
<td>Near site Biogas Production, Biogas Upgrade and Pipeline Injection</td>
<td>Off site Biogas Produced by Farm sized Digesters, Pipeline to Centralized Upgrade Facility and Pipeline Injection</td>
</tr>
<tr>
<td>Energy Production</td>
<td>744 MWh</td>
<td>1,488 MWh</td>
<td>94.4 million cu.ft.</td>
<td>94.4 million cu.ft.</td>
</tr>
<tr>
<td>Economic Performance</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>$1.5 m</td>
<td>$1.7 m</td>
<td>$9.7 m</td>
<td>$16.2 m</td>
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<tr>
<td>Digestor</td>
<td>$1.15 m</td>
<td>$1.2 m</td>
<td>$5.7 m</td>
<td>$11.2 m</td>
</tr>
<tr>
<td>Energy Conversion</td>
<td>$350 k</td>
<td>$500 k</td>
<td>$4 m</td>
<td>$5 m</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>4%</td>
<td>8%</td>
<td>6%</td>
<td>6%</td>
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<tr>
<td>Annual Expenses</td>
<td>$145 k</td>
<td>$232 k</td>
<td>$1.33 m</td>
<td>$1.7 m</td>
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<td>Annual Revenues</td>
<td>$127 k</td>
<td>$245 k</td>
<td>$1.4 m</td>
<td>$1.4 m</td>
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<td>Energy Sales</td>
<td>$76 k</td>
<td>$131 k</td>
<td>$826 k</td>
<td>$826 k</td>
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<td></td>
</tr>
<tr>
<td>Required Annual Revenues</td>
<td>$262 k</td>
<td>$365 k</td>
<td>$2.06 m</td>
<td>$2.93 m</td>
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<tr>
<td>Revenue Surplus (Shortage) vs. Required Revenue</td>
<td>($135 k)</td>
<td>($120 k)</td>
<td>($670 k)</td>
<td>($1.54 m)</td>
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<tr>
<td>Revenue Increase Required</td>
<td>52%</td>
<td>33%</td>
<td>32%</td>
<td>53%</td>
</tr>
<tr>
<td>Cost of Energy</td>
<td>$0.28 / kWh</td>
<td>$0.17 / kWh</td>
<td>$10.79 / 1,000 cu.ft.</td>
<td>$20.52 / 1,000 cu.ft.</td>
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<tr>
<td>Current Energy Price Shortfall</td>
<td>$0.21 / kWh</td>
<td>$0.09 / kWh</td>
<td>$6.62 / 1,000 cu.ft.</td>
<td>$16.35 / 1,000 cu.ft.</td>
</tr>
<tr>
<td>Productivity increase required</td>
<td>283%</td>
<td>128%</td>
<td>159%</td>
<td>392%</td>
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</tbody>
</table>

In addition to analyzing the four scenarios, a sensitivity analysis was performed to determine the relative effects of changing individual model assumptions. The sensitivity analysis found that revenues and capital costs have the largest influence on profitability, followed by operating expenses and debt ratio, while expected IRR of investors has a relatively minor influence on a project’s financial feasibility. The interpretation of the model results and their implications for the future feasibility of dairy digester projects are discussed.

**Conclusions from the Modeling of Dairy Digesters in California**

Based on the financial modeling exercise, none of the four digester scenarios modeled would be able to generate sufficient revenue under 2010 conditions to supply a rate of return that will stimulate investment in dairy digesters, based purely on financial considerations. Dairy digesters receive too little revenue for the electricity produced when sold to the public utilities to justify the high capital costs for these systems, and additional revenue streams are currently insufficient, unavailable, or uncertain. Co-digestion on small dairies and large-scale digesters converting gas to biomethane for pipeline injection approached financial feasibility in the modeling exercise. Although it was not modeled, it is clear that the most economically feasible system would be a large-scale biomethane system with co-digestion.

For dairy digester projects to become financially viable, they have to cost less to build and run and generate larger revenue streams. Construction costs can be reduced through technological advances or regulatory mechanisms such as grants and tax incentive. Operating costs can be reduced through technological advances and with experience. However the extent of cost reduction possible may be limited or at least slow, especially considering that costs tend to be reduced once a large number of systems have been built, leading to a “chicken and egg” problem. This problem can be overcome if the revenues generated by dairy digesters are high enough to attract investors.

Revenues for dairy digester projects can come from the values of energy (electricity, heat, and biomethane), liquid digestate (fertilizer), solid digestate (compost), renewable energy credits, and carbon reduction credits. However, the current value of these commodities is either too low or not captured by dairies. Feed-In Tariffs for biogas electricity in California are currently set according to the Market Price Referent for non-renewable natural gas. Heat is often wasted. Renewable energy credits are forfeited to some utility companies as part of the power purchase agreement. Liquid digestate may become a wastewater stream rather than a value-laden product. Carbon markets have yet to materialize.

Reversing these trends and improving digester productivity (through technological advances or by adding co-digestion feedstocks to the manure) will go a long way towards fostering adoption of anaerobic digestion technologies on dairies. This will in turn reduce capital and operating costs, making the projects more economically favorable. However, based on the financial modeling exercise it seems likely that no single change will be sufficient to overcome the current revenue gap for dairy digesters. It will likely necessitate a combination of improvements in different
revenue sources (i.e., better feed-in tariffs, renewable energy credits, and greenhouse gas reduction credits), as well as technological performance and cost improvements.

These conclusions echo the general view in the renewable energy field toward dairy digesters. There is much potential for using anaerobic digestion to reduce odors and emissions on dairies and extract renewable energy from manure in the Central Valley of California. However, the currently available systems are too expensive, and the financial incentives to encourage wide-spread adoption of the technology have not fully matured.

Version History

The three final reports contained herein have been revised pursuant to comments provided by the TAG and additional project team members and other stakeholders. The draft and revision history of all reports submitted to the CVWB is as follows:


3b. **Economic Feasibility Model Findings for Dairy Manure Digester and Co-digester Facilities** (April 2011, Final). The April 2011 Final version was revised on the basis of various TAG comments.

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Report References
References are provided at the end of the first two reports:

Key Factors Determining Economic Feasibility

Economic Feasibility Model Approach

TAG Written Comments
All written comments on the draft economic reports from the TAG are identified in the Table of Contents for Appendix A
Report 1
Key Factors Determining Economic Feasibility
REPORT 1
Key Factors Determining Economic Feasibility

1.1 Executive Summary

Extensive research and review was conducted on published industry analyses on anaerobic digestion and the use of dairy manure for bioenergy within California and elsewhere within the United States. This information was compiled into a draft report that received significant comment by the TAG. The report was revised to include many of these comments. The revised version of the report was also reviewed by the TAG, and generated an equal number of comments as the first draft. This final version of the report consists of the revised report with the second round of comments appended (Appendix A) to show the diversity of ideas and issues that bear on this topic. All comments have helped the accuracy and completeness of this report and are greatly appreciated.

Numerous factors are identified as key contributors influencing the future economic viability of the potential development of dairy manure digesters and co-digesters within the Central Valley. The factors determined to be important economic drivers (both positive and negative) are summarized below:

- **Conventional Energy Prices.** Most fundamentally, current and projected future commodity prices of natural gas and electricity are critical underlying revenue constraints for dairy digesters. In terms of its physical uses, natural gas is a readily available substitute for dairy digester produced biogas and biomethane. Consequently, most potential customers will be unlikely to buy biogas or biomethane at prices much above their commodity price for natural gas. Similarly, the value of biogas generated electricity will be limited by the prices of electricity from comparable conventional energy sources. Currently, long term natural gas and electricity prices are not forecast to increase materially (adjusted for inflation) due to recent discoveries of new domestic shale gas reserves. While future California electrical price may increase at a greater rate than inflation, the price increase will be primarily driven by the California Renewables Portfolio Standards (RPS) requirements. Consequently, biogas cannot expect substantially improved feasibility from market-driven future commodity price escalation.

- **Regulatory and Legislative Support.** Federal and state grant funding, low interest loans, tax incentives and pilot programs have all played a vital role in past digester development in California. In addition, recent RPS regulations provide new market incentives distinguishing the value of digester-based methane and electricity from conventional non-renewable energy. Senate Bill (SB) 32 provides legislative support for manure digestion as its implementation may potentially improve and increase the power purchase prices of the recently initiated Feed-In-Tariff program (FIT) for small renewable generation.\(^1\) Both the amount and form

\(^1\) FIT electricity purchase prices are currently set at the Market Price Referent (MPR), a benchmark price primarily tied to the cost of electricity produced with natural gas. As a result, FIT prices do not recognize the full value of
of future public sector support can have a strong positive role in fostering manure digester implementation within the Central Valley. Future government support is expected to remain essential for continued development of manure digester systems.

- **Role of Utilities.** Local utilities are key potential customers for surplus energy production from dairy digesters and are also essential participants for digester-based energy projects interconnecting to the natural gas pipelines or the electrical grid. The state's major gas utilities are working to facilitate biogas injection to its gas network - biogas producers can access the pipeline system provided that they meet the gas quality standards and interconnection requirements, including system capacity constraints governed by applicable tariffs. Interconnection costs can be a major barrier for some projects. Significantly streamlined (and/or if possible utility cost shared) interconnection procedures for would improve the economic feasibility of digester-based gas and electricity projects. Utilities also face regulatory restrictions that limit both their involvement and, most importantly, the prices that they can pay for dairy digester energy. Nevertheless, innovative and constructive partnerships between digesters and utilities could offer a key potential mechanism for greater and more cost-effective development of biogas as a renewable resource.

- **Access to Capital and Third Party Developers.** The current financial difficulties facing most dairy farmers and the generally tight credit market will ensure that funding for digester developments will be scarce and costly for the foreseeable future. While increased participation by third party developers may provide some technical and financial assistance, private capital will be relatively costly. The potential “capital crunch” constraints will be especially acute for those projects that require major construction, involve new technical applications and/or supply energy to less established and developing non-utility markets. With sufficient prices and contracting mechanisms, third-party developers could play a key role in widespread digester deployment, creating standardized development processes and ongoing operations, enabling capital efficiency and cost reductions, and making it easier for dairies to host digester electricity and biomethane projects.

- **Air Quality Regulation of On-site Electrical Generation.** On-site generation of electricity represents a potential direct, “lower tech” and inexpensive beneficial use option for biogas. Recent air quality restrictions within the Central Valley may preclude this use. However, if cost effective compliance technologies or mitigation can be developed, digester systems could be greatly enhanced – especially if feed-in tariff revenues increase the revenue potential sufficiently for small scale distributed energy production to be developed.

- **Cost and Minimum Size for Biogas Upgrading.** Biogas scrubbing and conditioning for biomethane production is currently costly and can only be cost effectively performed at production levels significantly greater than most individual dairy operations can support. Combined with biogas upgrade system costs, system design and location requirements represent key factors limiting the feasibility for widespread development of biomethane facilities for the foreseeable future.

- **Proximity to Feedstocks and Energy Infrastructure.** The location of potential dairy digester and co-digester systems can be critical to the facility’s ability to obtain sufficient manure (and possibility feedstocks for co-digesters) and/or supply its biogas and other facility products to potential buyers at an attractive price.

- **Permitting.** Facility development design and permit costs to comply with state and local regulations can represent major delays, risks and financial expenses that may discourage potential digester development. The Program EIR has the potential to significantly reduce the delays and costs of digester projects if a streamlined process can be developed for electricity produced with biogas (e.g., renewable energy credits (RECs) that help achieve the RPS) and its prices may be poorly suited for setting renewable energy pricing and insufficient to support digester development.
Key Factors Determining Economic Feasibility

1.1 Digester projects that improve a dairy’s existing manure management system and do not substantially change the nature of the discharge.

- **Technological Change.** Although many of the core digester and biomethane technologies are fairly well established, future commercialization of dairy manure digester systems may be expected to result in some cost effectiveness improvements. However, currently most foreseeable improvements appear to be incremental rather than fundamental. Consequently, most analysts suggest that per unit production costs for biomethane and related electrical generation will remain higher than commodity energy prices and hence public support for production will remain necessary. Key technology breakthroughs that could dramatically improve future dairy digester profitability include cost-effective on-site electrical generation with biogas (e.g., very low emission internal combustion engines, micro-turbines or fuel cells) or inexpensive, efficient and/or farm sized biogas upgrading systems with low-pressure distribution line injection.

Many other factors will also contribute to the profitability of dairy digester systems. Generally, the effects of the other factors are secondary compared to the economic drivers identified above. For example, many analyses have investigated the potential for revenues gains from digester byproducts (e.g., digestate sales), tipping fees (for co-digester), or the environmental attributes of anaerobic digesters (e.g. carbon offsets) as important feasibility factors. However, the magnitude of these often speculative revenues will likely remain secondary to the value of the digester’s primary product, which is biogas.²

1.2 Introduction

The technological feasibility of biogas production from manure digesters and co-digesters is well established. Generally, digester produced biogas has been used for on-site generation of electricity and/or heating to meet the farm needs. Farm digester systems typically can produce three or four times the amount of energy that their farm’s need. This surplus biogas production represents a significant renewable energy resource with considerable potential economic value and environmental benefits.

However, to understand and evaluate the economic and environmental trade-offs associated with future manure digester and co-digester systems in the Central Valley of California, the key factors determining the economic feasibility need to be determined. Three basic types of economic factors can be identified: revenue factors, cost factors and implementation/development issues.

The balance and interrelationships of these factors under the specific project circumstances will determine the project’s overall feasibility. Most simply stated, if the average revenues (i.e., on a per unit basis) are greater than the digester’s average cost of production, then the project will have a positive benefit-cost ratio and will, in a basic sense, be economically feasible. However, to fully assess the project’s feasibility, implementation factors should also be considered to determine the likelihood that successful future development can occur.

² One notable exception is the potential for implementation of Assembly Bill (AB) 32 and/or a Federal cap-and-trade system to create a compliance market in which the carbon offsets from dairy digesters could create a major additional project revenue stream.
Revenue and costs naturally face tradeoffs in the project’s feasibility as increased costs are usually necessary to generate higher revenues. The key for improving a project’s feasibility occurs when the marginal revenues are greater than the marginal cost required for the revenue growth.

Each factor will have both technical and financial components determining the magnitude and nature of its effect on the system’s feasibility. Generally, economies of scale associated with greater production efficiencies will result in a lower production cost per unit. Similarly, at a fixed rate of production, higher sale revenues (or reduced production costs) will increase the revenues per unit. In both cases, the system’s economic feasibility will be improved.

The following analysis provides a brief description of the key factors affecting the economic feasibility of digester systems. The nature and extent of each factor’s contribution or role to the economic feasibility is also identified and evaluated. The central purpose of the analysis is to identify those economic or technological “drivers” that play a major role in determining the viability of digester system development. Expected future trends that might alter the system’s overall economic feasibility are discussed.

The analysis generally discusses manure digesters and unless explicitly noted otherwise, should be read as also applicable to and inclusive of co-digester systems. In addition the report maintains an important distinction between biogas and biomethane. Biogas is generally synonymous with raw biogas. Biogas produced by anaerobic digesters that has a methane content of between 50 percent (plug flow and tank digesters) and 70 percent (covered lagoon). Biomethane refers to refined biogas with higher methane content, typically 95 percent or more.

Finally, it should be noted that this analysis primarily addresses “economic” feasibility issues and as such considers the general costs and benefits of manure digesters. Strictly speaking, “financial” feasibility analysis typically refers to a more specific and comprehensive determination of the revenues and expenditures for a well-defined and site specified project. As such, a financial feasibility analysis would typically provide a more detailed description and estimates of project costs and revenues, consider its business cash-flow and include greater characterization of applicable market conditions and other considerations – primarily from the perspective of the potential owner/investor. Nonetheless, financial and economic factors are often used interchangeably. Unless specified otherwise, references to financial issues will refer to a more general economic assessment of cost and revenue issues.

The economic feasibility for specific systems will depend not only on general feasibility factors but may also depend upon site- or system-specific considerations. Nonetheless, important general observations can be identified and assessed.

### 1.3 Revenue Factors

The revenues generated by a future digester are central for its economic viability. Typically, it is more difficult to estimate future revenues than it is to estimate future costs which are easier to specify.

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3 Except in cases where equipment of facility requirements or cost / revenue thresholds may result in a “step-function” cost.
This is particularly true in the case of a new or emerging market (e.g., such as biomethane) where the potential customers and future product applications are difficult to identify and fully evaluate.

The following section provides a brief overview and assessment of the various factors that will influence the potential revenue performance of future anaerobic digester development in the Central Valley of California. When possible, the relative magnitude and any significant future revenue variables are also reported so that those factors that are current and future revenue “drivers” can be identified and their inter-relationships with cost and implementation better understood.

**Biogas Productivity**

The efficiency and effectiveness of biogas / biomethane production of manure digesters and other related production processes is a central factor in determining economic feasibility. All else being equal, greater biogas production will increase the system’s revenue potential and hence cost-effectiveness.

Currently, most dairy digester produced biogas is used on-site for energy generation. Electrical production is generally the primary use of the produced biogas although heat is frequently also produced for use in the anaerobic digester either as part of a combined heat and power system (CHP)\(^4\) or separate dedicated boiler systems. Consequently many of the feasibility studies for manure digesters report their productivity and costs in terms of the system’s electricity production.

**Overall System-wide Estimates**

There is a wide variance in the methane and electrical production rates estimated for manure power systems. The potential biogas production will not only depend on the anaerobic digestion process used but also on both the volume of biodegradable organic materials in the collected manure and the length and type of manure collection and storage used. Similarly, the amount of electricity that can be produced by the digester system will also depend on the electrical generation system used.

The California Energy Commission (CEC) conservatively estimates an average 36 cu.ft. of methane per cow\(^5\) per day (with an energy content of 36,000 Btu/day) which can generate 0.107 kW of electricity. The EPA estimates that manure digesters can typically produce 38.5 cu.ft. of methane per cow per day (EPA, 2004).

Actual daily electrical generation performance at Hilarides Dairy was substantially less at 0.055 kW per cow (though partly due to substantial biogas flaring during the evaluation period) (WURD, 2006). Craven Farms reported achieving daily energy values of 34,500 Btu/cow with a 0.096 kW per cow electricity generation rate that is comparable to CEC estimates. Other studies suggest 0.14 kW per cow (Electrigaz, 2008), and 0.1 kW per cow (Black & Veatch, 2007) as reasonable daily electrical productivity projections. Other analysts have more optimistic estimates of the per cow energy values.

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\(^4\) The thermal energy recovered in a CHP system can be used for heating or cooling farm facilities. Since CHP captures the heat that would otherwise be lost in traditional electrical generation, the efficiency of an integrated system is much greater (up to 85%) than the separate systems combined efficiency (45%) (ACEEE, 2010).

\(^5\) Whenever possible, production and cost projections have been normalized for a 1,000 lb dairy cow.
PG&E has estimated that each cow may generate 1,640 kWh annually (equivalent to 0.187 kW per cow).

Within these biogas production parameters, it is generally agreed that adequate biogas capacity can be attained by larger dairies for development of dairy digesters to be technically feasible, and to be potentially economically viable with sufficient revenue assistance.

**Specific Digester Systems**

**Manure Digesters**

Three primary anaerobic digester system approaches are commonly used to treat dairy manure. The system most suited for a specific dairy operation will generally depend on its manure management system. As of October 2009, 21 major anaerobic digester systems had been constructed and are currently operating within California. The digester systems vary from relatively small dairy farm facilities processing the manure wastes for approximately 200 head of cattle to very large dairies with up to 5,000 cattle.

- **Covered lagoon systems** are the most basic and traditionally the most inexpensive anaerobic digester systems to construct and operate. These systems use the highly diluted (typically with a 3% or less total solid content) output of “flush” manure handling systems (the most commonly manure management system used by California dairies) to produce a high BTU (up to 70% methane) biogas. Covered lagoon digesters generally are unheated (ambient temperature) and are well suited for co-digestion of whey, vegetable washing wastes and similar agricultural co-substrates (Gallo Farms) but are not well suited for co-digestion with heavier more concentrated feedstocks (e.g., grease). Average retention time for manure processing is 45 to 60 days. The biogas conversion rates for covered lagoon systems are generally 35% to 45% (Burke, 2001). Covered lagoon systems are currently the most widely constructed and operated dairy digester systems in California.

- **Complete mix systems** consist of a tank constructed of either reinforced concrete or steel. The digester contents are periodically mixed and frequently heated to maintain an optimal temperature for methane production. As a result, complete mix systems are more expensive to construct and require applied energy to operate. These systems work best with slurry manure with a total solids content of 3% to 10%. As a result they can be used by managed flush manure management dairies or scrape manure dairies if water can be added to the collected manure. Complete mix systems are well suited for co-digestion and have a relatively short retention time of 15 to 20 days. Consequently they are also able to handle higher processing loads. Heated digestion (therophilic) with a complete mix system can be expected to increase biogas conversion rates to 45% to 55% (Burke, 2001). Currently, only a few complete mix digester systems are operating within California.

- **Plug Flow Digesters** consist of a long relatively narrow tank often built below ground. The digester requires semi-solid manure (i.e., with a total solid content between 11% and 13%) consistent with “scrape” manure management systems. Plug flow systems can be operated heated or unheated. The costs and biogas conversion rates for plug flow digesters are comparable to similar complete mix systems. Typical retention time for plug flow digesters are 20 to 30 days (Burke, 2001). Also, plug flow digesters are less well suited.

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6 In 2009 six operating digester systems have recently suspended or closed their operations due to financial difficulties or regulatory compliance issues.
for co-digestion use. Currently, 6 plug flow digesters current operate or recently operated within California.

Until recently, the price performance of the three digester systems were roughly comparable. The higher biogas production from managed digester systems (i.e., complete mix and plug flow) covered the additional construction costs. As a result, when adjusted for biogas production, the costs per cow for these systems were approximately the same (Martin, 2010). However, as result of recent imposed manure management regulations for Central Valley dairy farms, depending on their land and groundwater conditions, many farmers may be required to construct non-polluting lagoon systems. In such cases, the added costs of lining lagoons to be protective of water quality represent a cost not previously considered and could make complete mix and plug flow systems more attractive and cost-effective digester systems for biogas production, depending on the manure-management practices of the dairy, which remain a key factor in selecting a digester system.

Wider adoption and commercialization of digester systems may be expected to reduce system costs and improve performance – both from facility design improvements and better system management. However, the biogas productivity improvements will likely be relatively limited and incremental.

**Co-digesters**

The biogas productivity of dairy manure digesters can be greatly increased by the addition of other non-manure organic feedstocks. The proportional increase in biogas production will depend on the quality and suitability of the added feedstock. Food or agricultural wastes with higher oil or grease contents will generally release a greater amount of methane than other feedstocks with lower potential energy values. There is considerable variation amongst analyses in the amount of additional methane that co-digesters can produce. A conservative analysis for the CEC observed approximately a 35% improvement in methane production by co-digestion (CH2M Hill, 2007). Other commenters suggest that high energy feedstocks (e.g. fats, oils and greases or municipal organic wastes) could result in a doubling or even tripling of biogas production by dairy digesters (Hintz, 2010). Such industry analysts projected that the potential for major gas productivity improvements (supplemented by tipping fee revenues with longer term contracts for handling the municipal green wastes) will make a substantial improvement in the economic feasibility of biogas production (Best, 2010).

Co-digestion is more management intensive and could add greater reporting and oversight requirements to comply with water quality and solid waste regulations. However, the additional equipment costs for enhanced production should be minor (presuming the feedstock handling, preparation and storage requirements are limited). Consequently, many analysts suggest that co-digestion can provide cost effective biogas production gains.

However, availability of suitable feedstock will be important for determining the practicality and cost effectiveness of co-digestion. Many analyses identify potential tipping fee revenues for the

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7 It is presumed that co-digestion will not substantially alter the value or use of the resulting digestate except for the negative aspects from potential net nitrate and salt increases associated with the feedstock importation to the dairy.
digester operator from the feedstock sources as an important additional revenues source. However, as discussed later under the discussion of by-product revenues, most potential agricultural wastes are only seasonally available and may be located too far from specific digesters to be cost-effectively transported. Feedstocks also may become a commodity so that co-digester operators will likely have to obtain a variety of different feedstocks.

**Centralized Digester**

Only a few studies have assessed the economic feasibility of centralized digesters within the United States. Feasibility studies for centralized digester systems in New York state, southern Wisconsin and Oregon concluded that the proposed systems were uneconomical (Bothi, 2005; Reindl, 2006; DeVore, 2006). Analysis for a centralized manure digester in Dane County, Wisconsin projected significant cost efficiencies compared to individual systems but still required major public and private sector support.

A few large centralized manure digesters have been constructed and operate in the United States. The Inland Empire Utilities Agency’s (IEUA) Chino Basin project in South California was the first centralized anaerobic digester to be developed in the United States and is the only centralized digester facility currently operating in California. The IEUA project came online in 2002 and processes 225 tons of manure per day from 6,250 dairy cows, plus food waste from local food industries. The manure is trucked to the facility from six farms located within 6 miles of the digester (Davis, 2009).

However, currently all of these centralized digesters are in effect demonstration projects having received major funding assistance and have faced significant operational difficulties. The Chino Basin facility itself received approximately $5 million of its $8.5 million construction cost from the USDA’s Natural Resource Conservation Service (NCRS) for watershed protection. The CEC provided approximately $2 million in funding with the remainder provided by the Inland Empire Utilities Agency (IEUA) that owns and operates the facility. The energy generated from the biogas powers the agency’s off-site groundwater desalinization plant and wastewater facilities.

Large scale biomethane production requirements are a primary rationale for centralized digester systems. Although there are potential limited economies of scale for the centralized digester, manure transportation and handling costs can offset the economic savings if there are not sufficient suitable dairies willing to participate in close proximity to the proposed facility. Given geographical constraints on the economies of scale the centralized digester systems represent a secondary factor for digesters’ economic feasibility. Currently, there are only limited future system enhancements foreseen that would improve their cost-effectiveness.

**Electrical Generation**

Electrical generation is currently the primary use of digester biogas within California. Biogas (and biomethane) can be used to generate electricity using a variety of technologies including reciprocating engines (e.g., such as internal combustion), microturbines, gas turbine and fuel cells. Electrical

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8 Only Vintage Dairy facility near Fresno uses the majority of its biogas production for biomethane production and injection into the utility grid.
generation with digester gas represents a promising distributed generation (DG) technology offering not only the environmental benefits of offsetting fossil fuel use but also has the additional benefit of destroying methane which otherwise would have major greenhouse gas impacts.\textsuperscript{9}

Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in the determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. This emission standard has been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards.

Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, currently properly operated “clean burn” IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations (Joblin, 2010). While additional selective catalytic reduction can in some cases be used to further reduce emissions, the necessary secondary emission controls are expensive and difficult to operate on lower energy fuels such as unrefined biogas. Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 - 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010).

Microturbines are a newer technology that is becoming increasingly available. While potentially well suited for low emission electrical generation using biomethane, microturbines generally require relatively consistent operating conditions, do not operate well under hot climate conditions (e.g., such as during summer months within the Central Valley) and are sensitive to the effects of hydrogen sulfide impurities present in the biogas. However new turbine inlet cooling designs are being developed which may offset the efficiency loss under hot climate conditions. Recent implementation efforts at dairy digesters have been mostly unsuccessful as reliability issues could not be solved for on-farm uses (Dusault, 2010). Industry representatives suggest that since the initial round of microturbine installations in the early to mid 2000s, experience from implementation may enable future microturbines to meet current San Joaquin Valley NOx emission limits without relying on costly catalytic post exhaust clean up. Analysts also suggest that at comparable implementation scales, the thermal conversion efficiency of microturbines will typically be 5% less than internal combustion (IC) engines.

\textsuperscript{9} Distributed generation also potentially offers additional system benefits of reduced system-wide transmission line infrastructure requirements and possibly reduced peak power system capacity requirements. However, at a farm-level, most dairies are likely at the end of the radial distribution system and may require local system upgrades to export electricity.
Compared to natural gas, the reduced efficiency rates for biogas electrical generation reflect the biogas’s lower methane and higher impurities content.

Some analysts state that new lean-burn reciprocating engines are delivering 32% efficiency with biogas for 90 kWh / 1,000 cu.ft. of biomethane and that a reciprocating engine custom designed for biogas can run at high efficiencies and ultra-low emissions without the use of costly and intensive after-treatment (CalBionergy, 2010).
possible that major technological advances could provide major improvement in the cost-effectiveness and/or environmental performance of future biogas electrical generation systems.

**Commodity Prices of Energy**

**Natural Gas**

Generally speaking, biomethane offers additional benefits to utilities compared to biogas generated electricity since the biomethane can be more readily stored for later use. Consequently, it is easier for utilities to manage biomethane for its highest and best use as an energy resource (i.e., during periods of higher energy demand).

The contract price for biomethane sales will be determined by individual negotiation with between the producer and utility. The utility gas purchase contract will also be subject to CPUC approval. In a fundamental way, the commodity price of natural gas constrains the economic value and sale price for digester system produced biogas and biomethane. Natural gas is a substitute energy alternative for on-site biogas use, off-site commercial sale or upgrading to biomethane. If the renewable and environmental attributes of the produced biomethane are considered separately (i.e., Renewable Energy Credits [RECs] and greenhouse gas [GHG] credits), then the core value of biomethane will be largely limited to the substitution cost for potential purchasers (e.g., such as industrial users or utility) to use natural gas to meet their energy needs.

In past years, the price of natural gas has fluctuated greatly. The price variability had been partly due to the major international oil price fluctuations and global economic instability. During 2009, natural gas price in California for PG&E averaged approximately $4.13 /1,000 cu.ft which was 52 percent lower than the 2008 average price (FERC, 2010). Extensive future supplies of domestic natural gas are currently believed to be available and ongoing technological improvements in natural gas recovery are expected to enable natural gas production to increase over the next 25 years. During that period, natural gas prices are expected to remain unchanged in real terms (USEIA, 2010).

While long term stable natural gas prices (in real terms) are good for the general economy, the absence of any significant future natural gas commodity price increase will undercut the future economic feasibility of biomethane production. If the future sales prices for biomethane continue to be constrained by natural gas prices, any future production costs increases (in real terms) can be expected reduce the profitability of biogas production unless offsetting technological improvements are achieved.

Currently, PG&E’s only permits biomethane pipeline injection into its transmission pipelines and has a minimum volumetric flow requirement of 120 Mcf/day so that the metering equipment can function adequately. End use consumer demand is a key limiting factor preventing use of the distribution for biomethane injection as there is insufficient demand within its distribution network during the summer for the biomethane. In addition, mandating injection into the transmission system insures that in the case of the digester’s scrubbing system and protective equipment failure, customers would not receive a slug of untreated biogas which harm downstream appliances or
1. Key Factors Determining Economic Feasibility

pose a serious health hazard. Instead, any untreated biogas released within the transmission system would be blended with the natural gas to reduce the potential for harm to downstream customers. Furthermore, any biomethane injection to the transmission pipeline will likely need to occur near urban areas with adequate year-round natural gas demand to off-take the injected biomethane.

At the time of writing, an initial pilot project at the Vintage Dairy near Fresno is currently operating and processes manure from approximately 3,000 cows into biomethane. The dairy has successfully upgraded its biogas to meet PG&E’s gas quality requirements. Vintage Dairy is located along a natural gas transmission line and therefore is able to inject on-site. In PG&E’s experience, biogas injection projects more than 4 to 5 miles from a transmission pipeline are less economically viable (PG&E, 2009). Other studies and analysts have also concluded that proximity to interconnection locations are a major limiting constraint for the feasibility of biomethane pipeline injection (Goodman, 2010). Consequently, the existing natural gas transmission system infrastructure is considered a key feasibility constraint for future development of any dairy biomethane pipeline injection within the Central Valley.

Biomethane could potentially be piped to local industry or commercial customers with sufficient energy needs. Again however, due to the relatively high cost of construction for delivery pipelines, proximity to the biomethane production facility will be a key feasibility constraint. Furthermore there are likely to be only a limited number of industrial or commercial users with adequate power demand.

Alternatively, biomethane can be compressed or liquefied for truck transportation and/or transportation fuel use. The California Low Carbon Fuels Standard established by Executive Order S-01-07 and the subsequent Assembly Bill 118 (creating the California Energy Commission’s Alternative and Renewable Fuel and Vehicle Technology Program) aim to encourage future biomethane use as a transportation fuel. The biogas conditioning requirements for compression biomethane (CBM) or liquefied (LBM) are comparable to those required for pipeline quality biomethane although specific users or fuel use may be accept higher carbon dioxide levels. As is discussed in the assessment of production costs, the purified biomethane must not only be compressed or liquefied, but on-site storage is also likely to be necessary until it can be truck transported to its end customers. Given their very similar chemical composition, the market prices for compressed CBM and LBM

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12 CPUC has also approved a PG&E contract with Microgy to acquire renewable biomethane from its Texas production facility as part of PG&E efforts to fulfill its RPS compliance requirements.

13 Under some circumstance and pending local air quality issues, it may be viable for “raw” biogas to be used for industrial or commercial heating systems. In which cases, if the relatively costly biogas upgrading are avoided, it could be economically viable to pipe the biogas further distances to commercial customers.

14 Subsequently amended by AB 109, the statue provides funding and authorizes the CEC to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state’s climate change policies.

15 Acceptance of higher carbon dioxide proportion will offer some production cost savings.
1. Key Factors Determining Economic Feasibility

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are expected to be highly comparable to compressed natural gas (CNG) and liquefied natural gas (LNG) prices.16

The commercial sales potential for CNG and LNG are currently relatively limited. However, CNG offers substantial fuel cost savings as prices in summer 2010 averaged approximately $2.25 per gallon gasoline equivalent compared to diesel’s current $2.70 per gallon gasoline equivalent (engprices.com 2010; CEC, 2010). The current market is primarily focused on sales as a “clean” transportation fuel for vehicle fleets. While municipal or government agencies have been major initial adopters of CNG vehicles, private companies are also considered potential customers. Presently, the main operational limits to CNG powered vehicles use is their horsepower constraints which make them less well suited for trucking use over major gradients. The greatest market demand for CNG fuel is within California’s major urban areas where the negative air quality effects of diesel trucks are highest and the CNG supply infrastructure can be most cost effectively developed.

Although, there are existing and future sales opportunities for CBM and LBM, it remains an emerging market that is constrained by the higher cost of conversion or purchase of CNG/LNG powered-vehicles and the need for expansion of the fueling infrastructure. Consequently, the value of both CNG and LNG are expected to remain closely related to natural gas prices with a relatively limited potential for any price “premium” for biomethane.

**Electricity**

Similar to natural gas, electricity prices have a central influence in determining the economic performance of digester systems. The “retail” electricity price that farmers currently pay to meet their on-farm needs determines a maximum economic value for their potential electric cost savings earned by self generation. The avoided cost for purchasing electricity at the utility’s retail price will offer direct economic benefit for dairies that can self generate electricity on-site to meet their electricity needs. Electrical generation for on-farm use and/or net metering plays a vital role in the economic performance of current operating dairy manure systems (PERI, 2009).

**Net Metering**

Retail electric rates in California are comparatively higher than elsewhere in the United States and consequently will increase the potential economic attractiveness of alternative energy sources. Currently, the typical base “retail” electricity price facing farmers within the PG&E service area is $0.12 kWh to $0.14 kWh. However, during peak periods electricity prices can increase to more than $0.25 kWh (PG&E, 2010).

In 1995, the California State Legislature passed SB 656 (Alquist), which required all electric utilities to buy back any electricity generated by a customer-owned solar and wind systems system. This buy-back program is known as “net metering” because the electricity purchases of the customer are netted against the electricity generated by the customer’s renewable system. The customer’s

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16 If the biomethane’s environmental attributes (e.g., renewable energy credits [RECs]) are valued separately. Given the nascent CBG and LBG markets it should be conservatively assumed that no major premium biogas price would be obtainable – especially given the relatively small production levels likely for the foreseeable future.
utility bill is calculated on the net quantity of electricity bought from the utility. However, the utilities were not required to purchase any surplus generated by the customer and it was only the subsequent Assembly Bills 2228 (passed in 2002) and 728 (passed in 2005) that required the utilities to offer net metering to dairy farms that generated electricity with biogas.

Past net metering regulations did not encourage digesters operating as electricity “exporters” since the program only allowed them to “bank” their energy production in the utility grid. As a result, biogas producers often chose to flare excess biogas rather than generate electricity for which they would receive no compensation from their local utility. In addition, dairy farmers do not receive the full retail price for their self generated electricity but still incur tariff charges for transmission and distribution, demand charges, public purpose funds. These additional costs can be considerable – averaging $0.055 / Kwh (in 2005 dollars) for a typical dairy (Krish, 2005). However, as of the end of 2009 the previous net energy metering program for biogas digester generators ended and no new net metering accounts are currently available although there is currently legislation under consideration to reactivate the tariff program.

**Feed-In Tariffs**

Following the passage in 2006 of Assembly Bill (AB) 1969 (and subsequent CPUC rulings), PG&E and other California utilities\(^{17}\) are now required to buy excess energy generated with renewable sources from qualified customers. Dairies that generate electricity can choose to sell their surplus electricity to their local utility under a Small Renewable Generator Power Purchase Agreement (PPA) provided they sell less than 1.5 MW of power (which at average of 0.107 kWhr / cow would be equivalent to surplus power production by 14,000 cows). This “feed-in tariff” program is in some ways a more sophisticated net metering program as the dairy’s usage and exports to the grid are both measured for quantity and by time of delivery. Under the feed-in tariff program, small renewable energy producers are able to obtain long-term contract for their energy production at a very low transaction cost which should assist in raising capital investment. This is a primary benefit offered by the feed-in tariff program to potential dairy digester developers.

Under the feed-in tariff program the purchase price for purchased power is set by the CPUC according to the market price referent (MPR) determined as part of the State’s renewable portfolio standard proceedings.\(^{18}\) The MPR values is based on the comparable costs for electrical production at large scale utility power plants and as such, is unrelated to the actual cost renewable energy production.\(^{19}\)

The prices paid for the purchased power is also adjusted for its “time of use” which recognizes the higher value of power supplied during on-peak periods and its lower value during off-peak hours.

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\(^{17}\) Although several utilities serve farmers within the Central Valley, PG&E is predominant utility provide for the region and consequently the analysis primarily refers to PG&E in its discussion of utility issues.

\(^{18}\) Additional information on the CPUC’s Feed-In-Tariff Program is available at: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/feedintariffs.htm.

\(^{19}\) Some industry experts suggest that the MPR is too low to provide sufficient financial support for the development of new renewable energy projects. Consequently, the CPUC is currently also considering the implementation of “reverse auction” as future funding option for renewable power projects up to 10 MW in capacity. If approved, potential renewable energy producers could bid the rates at which they would supply electricity. The major utilities would then select the lowest cost bids from qualified producers. Such an approach could enable the producers to contract for renewable energy at higher than MPR rates.
Current MPR values are approximately $0.09/kWh and producers can enter into 10, 15 or 20 year contracts with the utility (CPUC, 2010).

The feed-in tariff program provides an improved mechanism for dairy digester to sell its electricity. However, the set price for the MPR price and low off-peak rates can nonetheless result in average electricity prices that may be insufficient to fully compensate for the electrical generation system costs. Furthermore, the long term contracting terms lack escalation provisions and this can be a disincentive for electrical producers deciding between participating in the feed-in tariff or net-metering programs. However, it may also be possible with suitable gas storage and design that a digester system could be operated beneficially as a peak power operation under the feed-in tariff program so that the dairy sells most during peak or partial peak periods (PERI, 2008).

While the feed-in tariff program improves the revenue potential for on-site electrical production, it does not maximize the economic benefits to the dairy. Under the current feed-in tariff programs, Californian generators are prohibited by regulation from “wheeling” electricity from the dairy – even amongst the dairy’s own electrical accounts. For example, a dairy farm with several electrical accounts (e.g., for refrigeration, irrigation systems, lighting and home use) will have to sell the power in excess of that it consumes on its producing electrical line (i.e., that connected to the generator system). Under the PPA agreement terms with the utility, the dairy would earn revenues (which may be near to a wholesale price) while at the same time being charged at a higher retail price for the electricity it is consuming on its other electrical accounts. Under this arrangement, the dairy loses some of its potential avoided cost savings that it could earn if it was able to fully serve its own electrical needs from its own electrical production.

The feed-in tariff program is available on a first-come, first served basis and PG&E’s obligation for the program serving manure digesters and other non-water/wastewater customers will end when 104.6 MW of installed renewable generation will operate under the program. As of February 2010, only the Castelanelli Bros Dairy has enrolled in the program (PG&E, 2010).

The most recent analysis by the CEC predicts that California’s system-wide average retail electricity price will not increase in real terms between 2010 and 2016 (CEC, 2007). The CEC projections acknowledge the price effects of potential future policy changes in energy efficiency, renewables, siting, or climate change on electricity prices paid by customers are highly uncertain. If electricity prices remain stable, then there will be reduced economic incentives for on-site electric generation use of dairy digester biogas. Even if future California electrical price increase at a greater rate than inflation, the price increase may be expected to be primarily associated with the California Renewables Portfolio Standards (RPS) requirements or other policy related factors. Consequently, biogas cannot expect substantially improved feasibility from market-driven future commodity price escalation for electricity generation and/or natural gas.

In summary, electricity prices are a direct and fundamental driver of dairy digester feasibility. The revenue boundaries for digesters systems are determined by both the retail prices paid by electrical consumers and the wholesale prices and contract terms by which utilities will purchase any on-site surplus electrical production using biogas / biomethane. The terms of any feed-in tariffs, PPA and other price factors (e.g., time of delivery pricing) will determine and incentivize the dairies’ production levels and use/sale of their biogas. Currently, much of these terms are set by the CPUC.
regulations and policy which determine not only the MPR but also authorize the utilities’ prices to its consumers and their ability to “pass on” any electrical purchase costs. Similar to other distributed generation and renewable resources, these financial factors may be expected to have an important, albeit complicated role, influencing the economic feasibility for manure digesters in the Central Valley.

**Byproduct Values**

**Digestate Use Values**
Most feasibility studies of dairy digester systems estimate an economic value for use of the digestate by-products. Depending on its water content, the digestate can be spray applied to crops as a fertilizer supplement / replacement, used as compost material or livestock bedding material.

The quantity and form of the digestate will be related to the anaerobic process used. Lagoon digesters will result in predominately liquid digestate while the complete mix digesters typically produces a denser slurry digestate. The plug-flow process results in a wet solid digestate material. The digestate can be heated or otherwise dewatered to separate the solid fraction for use as a compost material or bedding. If a dairy farmer has insufficient land to accept all its digestate, the material can generally be transported short distances to other nearby farm operations. In many cases, the digester owner will earn a small payment for the effluent (Martin, P., 2010).

The extent that the digestate by-product can be used as a soil supplement or fertilizer replacement will depend on the farmland soil conditions and crop types as concerns about salt and nitrate loading limit its land application rates within the Central Valley. Currently, single crop farming in the region can typically accept approximately 2,000 lbs of manure or digestate per acre annually while double cropped fields can receive 3,000 lbs per year. Given that a cow will produce approximately one ton (2,000 lbs) of manure solid a year, the quantity of digestate that will remain after anaerobic digestion will be approximately 60% or 1,200 lbs per cow per year (Clear Horizons, 2006).\(^20\)

Some analysts argue that most digestate uses should not be recognized as an additional revenue source for the digester since the dairy’s manure would otherwise be similarly reused on-site. In which case it may be argued that no new net revenue has been generated unless manure or other feedstocks (if co-digestion is occurring) has been imported (Hall, 2010).

In any case, the potential value of avoided bedding costs will be very minor. Although bedding sales of digestate are commonly estimated to be approximately $20 - 25 per ton (Clear Horizons, 2006), according to USDA statistics, less than 0.28 percent of the total dairy budget was spent on bedding and litter materials for the average California dairy operation (USDA, 2005). Consequently the avoided cost of digestate use for bedding or revenues from their sales can be expected to have a minimal if not negligible effect on the economic feasibility of any manure digester systems.

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\(^{20}\) Assuming substrate volatile solid content of approximately 65% (i.e., manure with bedding) of which 60% would be converted to methane.
The compost value of digestate is considered to be potentially significantly higher if it can be sold commercially.21 Green waste recyclers report sales of up to $18 per cubic yard ($90 per ton) (SAIC, 2002). However, wholesale values of the digestate may be far lower. In an analysis of a large centralized digester system Hurley estimates that the net value of the digestate would be $5 / ton which was consistent with several other studies (Hurley, 2007).

Again, given the relatively minor net value of the bulky digestate and recognition that it is arguable that any net material gain has occurred (and in actuality likely to have been a 40% loss in biomaterial material weight in the manure to digestate conversion), the value of the solid digestate as a compost revenue may be expected to have a minimal contributory effect to the digester feasibility.

**Effluent Use**

Digester effluent is typically applied to dairy farmers’ fields for feed crop production. As discussed above for the solid digestate, it is arguable whether any revenues or avoided costs associated with the use of the effluent by-product will represent a net revenue contribution. Unless organic feedstock material has been imported (which would increase the effluent quantity and/or fertilizer value), then the farmer’s fertilizer expenditure would be expected to relatively unchanged. Consequently, only co-digesters or centralized manure digester systems would be expected to generate net revenues from digester effluent use that would represent additional revenues potentially improving the project’s feasibility. Furthermore, if the location of the digester has insufficient onsite capacity to accept on-field applications of all the generated effluent (or solid digestate), then disposal of the effluent could add costs that would further decrease the project’s economic feasibility.

The potential applied fertilizer cost savings with effluent use will have greater potential economic than solid digestate uses. Furthermore, unlike the quantity of manure solids which is substantially reduced by the anaerobic digestion process, most of the nitrate, phosphorus and, to a lesser extent, potassium content will remain in the effluent and digestate. As a result, any use of imported feedstock will likely add additional nutrients. While such nitrogen and other salt accumulation can present potential water quality concerns if improperly managed or if the surrounding cropland is already at (or near) its maximum nutrient loading based on current operations, the high costs of fertilizer make it possible that effluent can have meaningful use value to the dairy and other nearby farms.22 Farm studies indicate that the fertilizer value of untreated manure can be significant – conservative estimates from a 1997 study estimate the annual value of untreated manure to be over $100 / cow (in 1997 dollars) (Hart, 1997). However, these fertilizer cost savings are also more applicable to higher value commercial crops rather than feed crops. Nonetheless, it can be reasonably expected that on a per cow basis, new net effluent gains would have some positive revenue value for the dairy.

It has been suggested by some industry analysts that large scale effluent treatment to separate out the nitrogen, phosphorous and other salts could generate highly valuable organic fertilizer byproducts that would be suitable for use by drip feed irrigation systems. Such an additional effluent processing

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21 Technically, the digestate is not actually compost material since it has not been aerobically decomposed, however it has very similar uses and nutrient value for soil application as compost.

22 It should be noted though that the site-specific soil and groundwater conditions may reduce the effluent’s value if the land application rates of local farmland are too restrictive.
1. Key Factors Determining Economic Feasibility

component to the dairy digester facility would be costly with developer costs and economies of scale similar to those necessary for biogas upgrading systems. However, given the high costs for fertilizer purchases, the high concentrate organic byproduct would have significant value which according to some experts could be a major economic driver for the digester system (Best, 2010). Furthermore, such a digester effluent treatment system would sequester nitrogen and salt thereby improving the dairy’s water quality management practices. Outside of California, effluent treatment can sometimes be a key driver of the economic viability of digesters, as there can be a significant avoided cost associated with phosphorus and nitrogen removed from the waste stream in certain locations.

In general, net effluent gains for co-digesters or community digester systems may represent a positive albeit relatively minor supplemental economic factor for system feasibility (subject to local farmland soil conditions).23

Tipping Fees (Co-digesters only)

Most co-digester studies argue that that tipping fees for the feedstocks processed by co-digesters are important revenue sources. Several studies have concluded that tipping fees can be crucial factors in determining the viability of the digester project (Moffatt, 2007).

However, it is essential that the net revenues for sourcing co-digester feedstocks are understood so that the net revenues to the digester project can be correctly determined. “Tipping fees” generally refer to the price paid for disposal of the organic wastes. In some cases, the waste producer may also incur additional transportation costs for removal of the waste. Co-digester operators sourcing feedstocks for their facilities will similarly need to recognize the costs for transportation (and possibility storage) of the feedstock to determine the cost-effectiveness of feedstock additions for their biogas production.

In most cases, waste-to-energy facilities are able to obtain a disposal or tipping fee for feedstocks that increase biogas production and add revenues that assist in offsetting facility construction and operating cost expenses. Such disposal fees currently range from about $50 to $60 / ton in California. However, most of the feedstocks are potential commodities for which supply, demand and prices are susceptible to change. Relatedly, most commercial feedstocks (e.g., agricultural or food processor wastes) are expected to be available only seasonally and on a short-term contract basis. Digester operators will likely have to obtain a variety of different feedstock materials from numerous sources. Municipal green waste is currently identified as one of the more reliable potential feedstocks. As competition increases for these resources this trend may reverse and tipping fees may decrease. Costs for collection, transporting and storing agricultural residues uses are typically in the range of $25 to $50 per dry ton. Transportation costs of $0.20 to $0.60 per mile per ton are typical for feedstock delivery (Jenkins, 2006). Other analyses have identified loading and unloading costs of $0.40 / ton (2007 dollars) with a $0.18 / ton / mile transportation cost (Moffatt, 2007).

23 Not including the development of major effluent processing component.
Tipping fees can offer additional revenues for co-digester systems but transportation and storage costs may reduce the net revenues for the digester operator. Given the uncertainties and geographic considerations associated with current and future feedstock commodity values, it is conservatively considered that tipping fees should be recognized as at most a minor secondary supplemental revenue source solely for co-digester systems.

**Greenhouse Gas Emission Reduction Credits**

There are two types of potential greenhouse gas (GHG) credits that may be derived from digester systems: (1) Credits for methane destruction (carbon offsets); and (2) Credits for Fossil Fuel Displacement (renewable energy credits).

Methane has 21 times the greenhouse gas impact of an equivalent weight of carbon dioxide (CO$_2$). Consequently, each ton of methane that is intentionally destroyed will have an equivalent GHG reduction value of approximately 21 tons of carbon dioxide. Use of renewable fuels for power generation also has a secondary benefit that carbon currently stored in fossil deposits is not added to the environment. Renewable Energy Credits (RECs) in effect account for the fossil fuel displacement effects and are discussed separately below.

A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including methane capture, reforestation, changes in manufacturing, destruction of high global warming gases, etc. A key characteristic of a carbon offset is that it must be “additional” (i.e., the offset provider must prove that the project would not have happened without its financial investment and that the project goes beyond “business as usual” activity).

The methane collection and use associated with anaerobic digesters systems can result in considerable reductions in GHG releases. Flaring of collected biogas will result in a net GHG benefit as methane is more than 21 times as potent a global warming gas as carbon dioxide. Productive use of anaerobic digester biogas will result in additional GHG benefits as the biogas generated energy will reduce the corresponding utility generated GHG emissions that would otherwise be necessary.

Currently, there is an emerging international and domestic market for greenhouse gas emission offset credits (often referred to as carbon credits). Both the European Union (EU) and Chicago Climate Exchange (amongst others) operate “carbon markets” for the purchase and sale of certified carbon credits. In addition, potential GHG credits have to be certified to verify their effectiveness. Numerous organizations operate GHG verification programs both within the U.S. and internationally (e.g., the Voluntary Carbon Standard Association and Gold Standard Foundation). The California Climate Action Registry (CCAR)$^{24}$ has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters and has more than seven projects which are currently generating carbon credits.

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$^{24}$ The California Climate Action Registry now operates as a program under the Climate Action Reserve, and 2009 was the last year it accepted entity emissions reports.
Presently participation in GHG markets is voluntary within the United States. Nonetheless, many businesses are currently purchasing carbon offsets to support projects that reduce GHG levels. Consequently sales of carbon offsets may be an additional revenue source for future digester projects. However carbon offset prices are subject to market conditions and price volatility. Between 2005 and 2007, carbon reduction credit values were as high as $50 per ton of CO₂ equivalent (outside of the US). More recently, carbon values have been considerably lower - typically in the range of $10 to $20 per ton of CO₂ equivalent internationally. Within the US, carbon prices have been between $1 and $10 per ton and recently prices have been closer to $5 per ton. Since the market is based on both the supply and demand for carbon credits, it is difficult to project the future carbon credit values.

PG&E currently operates its ClimateSmart™ program which allows participating customers to elect to pay an additional monthly premium to fund CPUC-approved projects that reduce GHG emissions.²⁵ ClimateSmart must acquire approximately 1.36 million metric tons of verified GHG emission reductions by the end of the program’s pilot phase. Due to this requirement, the ClimateSmart program is one of the largest single purchasers of California-based voluntary offsets in the state. Residential, businesses and municipal customers participating in the ClimateSmart program are purchasing GHG offset credits from environmental conservation, restoration and protection projects. PG&E estimates a current average carbon reduction price of approximately $9.88 per metric ton of CO₂ for its ClimateSmart program (Brennan, 2010). PG&E contracted for dairy farm GHG reductions at a rate of $10.80 to $11.00 per metric ton of CO₂ reduction (PG&E, 2010). Given an annual GHG impact equivalent to 4.6 tons of carbon per year, the current potential carbon offset value for qualified dairy digesters would be over $45 per cow.

A central issue for carbon credits is “additionality.” Additionality considers whether the GHG reduction is discretionary and whether the carbon offset purchase actually ensures carbon reductions. The CCAR strives to support only projects that yield surplus GHG reductions, which are additional to what might have otherwise occurred. If the carbon offset purchase is a key factor in making the reductions occur, the reductions can be considered to be “additional” to the business-as-usual case. If anaerobic digesters become the Best Available Control Technology (BACT) for dairies’ waste management, then digester collection of methane would no longer represent “additional” carbon reductions and so would no longer qualify as carbon credits. Under such circumstance, existing GHG credits would remain valid until the end of their ten year term but new credits would not be authorized (CCAR, 2007).

**Renewable Energy Credits**

Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.

²⁵ In June 2009 PG&E announced its first Climate Smart GHG emission reduction agreement with an 8,400 cow dairy in Kern County. The contract is for 75,000 metric tons of reduced GHG emissions between 2010 and 2013.
Renewable Energy Credits (RECs), as statutorily defined, are not created until electricity is generated. Therefore biogas digesters, unlike wind turbines and geothermal facilities, in and of themselves have no RECs to convey. However, if the digester biogas end use will replace the use of fossil fuels for energy production then the digester can qualify for fossil fuel displacement credits. As a renewable resource that can directly substitute for natural gas use, biomethane or biogas used for electrical generation or injection into the utility grid will qualify for REC credits.

The value of the fossil fuel credits also depends on the fossil fuel use that would be displaced. Consequently, California fossil fuel displacement credit values for electrical generation use are lower than elsewhere within the most of the United States due to the fact that very few coal fired power plants supply power to California. Under the State of California’s Renewable Portfolio Standards (RPS) requirements, there is an emerging market for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters. The generation of renewable energy from the dairy digester systems can be quantified and certified for sale as a renewable energy credits.

A digester system developer retains the RECs for self-generated power used on site while the utility receives the remaining REC credits for any surplus electricity it has purchased. Utilities and other entities that need these “green tags” to comply with California’s Renewable Portfolio Standard would be potential purchasers of digester RECs. In addition, other businesses wishing to support renewable energy might also be interested in purchasing digester power RECs. REC prices are subject to market conditions but are expected to be $0.02 to $0.05/kWh (CH2M Hill, 2006).

Currently, most RECs within California are sold bundled with the associated renewable energy. Consequently, utilities such as PG&E that are negotiating long term renewable energy purchases acquire the REC values with the resource’s material value as a fuel. Consequently, the sale price for the renewal resource has a price premium/component for the included REC. However, the price for feed-in-tariff for small renewable generation does not include the value of the REC, even though the REC is currently bundled with delivery of electricity under the tariff. The REC values for self-generated energy used by the dairy will be retained and would be potentially available for sale.

There are no established REC values for biomethane use as a transportation fuel. However, future implementation of the California Low Carbon Fuel Standard (LCFS) is expect by many industry experts to encourage the future of REC values applicable for future use of biomethane (either as CBM or LBM) as a replacement for diesel and gas fuel (Price, 2010). Although very difficult to value at this point in time, some industry experts maintain that the future REC values for biofuels could add additional revenues for digesters systems producing CBM or LMB.

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26 Consequently, biomethane production for use as transportation fuel will not qualify for RECs.
27 Coal-fired power plants account for approximately 0.8 percent of California’s electricity production.
28 The CPUC issued Decision 10-03021 on March 16, 2010 under its Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard (RPS). In the Decision, the CPUC adopted a temporary price cap of $50/MWh for RECs, which is the penalty amount for noncompliance with the RPS. This $50/MWh temporary price cap for RECs is used as the upper end of the range. The lower end of the range of value for RECs is based on the $20/MWh market price index for RECs for the Western Electricity Coordinating Council, as quoted by the CantorCO2 Environmental Brokerage.
29 The sale and purchase of tradeable REC’s for utility compliance with RPS was approved by the CPUC in March 2010 under decision R.06-02-012 proceeding; D.10-03-021.
Other Economic Benefits of Sustainable Farm Production

Currently, several of the farms with operating digester systems receive significant attention for their pioneering sustainability improvements and use of biogas as a renewable energy source. Hilarides Dairies use of cow power for its trucks and Fiscalini Farm’s use of its biogas for its cheese production are two notable examples. Similarly, the Straus Family and Gallo Farms also differentiate their dairy operations by their implementation of more sustainable farming practices.

However, as yet there is no appreciable market or economic value to these and other California dairies rewarding them for adopting more sustainable business practices. While “greener” businesses in other sectors may be able to leverage their sustainability commitments for an improved market position or marketing benefit, there is currently little potential for dairy farms to capture any such similar benefits. Due to California’s regulated milk sales market and relatively few dairy producers that sell directly to retailers, most dairy farmers are “price-takers” (LaMendola, 2010). Dairies such as Straus Family Farms that have a brand identity and sell their dairy goods to consumers are very few in number and represent a very small portion and niche of the dairy market. Premium prices for “greener” dairy producers are unlikely to be achievable in the foreseeable future particularly during a depressed economy and relatively low public awareness of the potential for more sustainable production practices such as dairy digesters. Furthermore, due to the largely consolidated market for most dairy goods and the perishable nature of milk itself, emergence of any sales premium or selection preference for dairy products from “sustainable” dairy farmers will likely require a considerable increase in prevalence and/or accreditation labeling (i.e., a “green” stamp of approval) before wholesalers and/or other large customers can and will begin to select amongst dairy producers for those more sustainable producers.

As a result, it is considered unlikely that dairy farmers will be able to gain any significant economic premium for their dairy products from their digester operations.

Government Grants and Assistance

Currently most operating digester systems receive considerable government funding assistance. Anaerobic digester projects qualify for many of the federal and state programs promoting renewable resource development. Governmental assistance and support can be provided in the form of form grant funding, low-interest loans, tax incentives and/or technical support.30 The main forms of government support currently available for biomethane production by dairy manure digesters are identified below. Individual digester projects will have to qualify for assistance on a case by case basis and projects will typically receive assistance from only a few programs.

Renewable Energy Production Tax Credit. Under this federal program authorized by the 2005 Energy Policy Act, qualifying renewable energy producers can obtain $0.015/kWh in production incentives. The program is currently authorized to continue until 2026.

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30 The Feed-in Tariff program authorized by the CPUC is discussed previously under the electricity price section.
USDA – Renewal Energy Program. The program provides grants and loan guarantees to rural small businesses and agricultural producers for up to 25% of the cost to purchase and install renewable energy generation systems up to $500,000.

Self-Generation Incentive Program for Renewable Fuel Cells. Authorized by the CPUC, this utility administered program provides financial incentives for installation of new, self-generation equipment installed to meet all or a portion of the user’s electric energy needs. The program was originally designed to complement the CEC’s Emerging Renewables Program (ERP) by providing incentive funding to larger renewable and non-renewable self-generation units up to the first 1 MW in capacity and subsequently increased for units up to 3 MW in capacity. Renewable fuel cell systems can receive a $4.50 /watt as a one time capital payment (but not to exceed 50% of the total cost). Non-renewable fuel cell systems can similarly receive a $2.50 /watt capital payment.

California Energy Commission - Renewable Energy Program. The Existing Renewable Facilities Program provides production incentives, based on kilowatt-hours generated, to support existing renewable energy facilities. In addition, the Emerging Renewables Program provides rebate funding for solar and fuel cells that use renewable fuels (such as biogas). The program has $65.5 million in funding until 2011.

State Assistance Fund for Enterprise, Business and Industrial Development Corporation: Energy Efficiency Improvements Loan Fund. This long standing state program offers low interest loans to small businesses in California for renewable energy systems. The maximum loan amount is $350,000 at 4% interest with a five year repayment period.

In addition to these current programs, the State of California (administered by the CEC) provided significant funding assistance to manure digester and other similar renewable resource projects through both its former Dairy Power Production Program and research conducted under its Public Interest Energy Research Program (PIER). As discussed previously in the Renewable Energy Credits discussion, the State of California Renewables Portfolio Standards (RPS) requirements also provides indirect support for manure digesters by fostering an emerging market within California for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters.

Recent economic analysis of dairy digester systems installed under the California Dairy Power Production Program determined that without government subsides, even the best constructed/operated digesters would have electrical production costs that are “high tending to be above market rates” (PERI, 2008). Even factoring in government subsides, the cost of energy for other digester systems were such that while several digesters were marginally profitable, several others operated at a negative rate of return.

Together these past and current programs illustrate the important role that state and federal programs contribute to fostering the development of manure digester systems. The financial and technical support is widely agreed to be an important and positive influence improving the feasibility of manure digester development. Furthermore, given the increasingly complex regulatory conditions facing dairy farms and renewable energy projects, as well as the financial challenges remaining before full commercialization of the manure biogas/biogas production is expected to occur,
continued governmental support is expected to remain an important and essential economic driver for future manure digester development for the feasible future.

### 1.4 Cost Factors

These costs typically will consist of both:

- Initial construction and equipment costs for development of the digester project. In many cases there may be significant economies of scale as the system capacity increases. The construction and/or equipment cost will also likely vary depending on the technology adopted.
- Operating and maintenance cost for the project. This will include the labor and input costs including required energy. Typically, these are variable costs and will vary with the level of production. The operating and maintenance cost may also vary depending on the technology adopted.

The following section identifies the major cost factors that influence the economic feasibility of biogas production by dairy manure digester systems. These factors are naturally inter-related with the revenue factors discussed above. Just as market conditions will determine the revenue potential for digester biogas and its other byproducts, technological and equipment supplier conditions will be key cost determinants on economic viability. Consequently, major technological improvements that greatly decrease unit production costs will enhance the economic feasibility of dairy digester development. Conversely, additional equipment / processing requirements (i.e., as result of new regulatory compliance requirements) that increase unit production costs will reduce the dairy digester system’s economic viability.

As will be discussed below, economies of scale can have an important role determining unit production costs and consequently the economic feasibility of the system. In some cases, scale issues will be limiting factors. Major equipment components may require minimum quantities of process throughput to operate adequately and in such cases these technological/operational constraints may dictate system design parameters.

Finally, it is worth noting that costs are generally easier to estimate than revenues which typically face more future variables. This is particularly apparent when the digester system’s operating assumptions and conditions are defined. Review of past digester studies offer far greater cost information than is provided for their revenue projections. In any case, care should be taken to ensure that estimated costs are properly matched with operational / output assumptions. It should also be recognized that site specific conditions can both positively or negatively affect the actual system development costs considerably.

**Manure Collection / Preparation as Feedstock**

The dairy manure collection costs for on-farm digesters are considered to be negligible since similar manure management practices are already a necessary component of existing dairy operations. Furthermore, the transportation distance within the farm will be very limited. In addition, relatively
little pre-digester preparation is expected to be necessary for the manure. Any grinding or filtration necessary will be very minor in cost compared to the digester itself.

For a centralized or community digester system, manure transportation costs may be a limiting factor that could offset economies of scale that might be gained from larger anaerobic digester facilities. Manure from the individual farms could either be piped to the centralized digester through a sewer system or possibly be transported by trucks. Analysis by Ghafoori and Krich suggest that development of a piping system for dairy manure is prohibitively high from a construction cost basis (Ghafoori, 2005; Krich, 2005). Furthermore, such systems would incur major additional investment cost and could face significant additional difficulties with site and easement requirements.

Anaerobic Digester Systems

As discussed previously, anaerobic digester systems are relatively simple and well established technologies. Although there is potential for future productivity improvements, construction specifications and costs are relatively well defined. Most of the system components are relatively standard and readily available. Other construction costs (e.g., such as siting and land preparation) will be relatively straightforward.

The selection of specific anaerobic digester technologies will be primarily determined by the dairy’s manure management systems. While site specific requirements may necessitate some tailoring of digester configurations, construction costs should be relatively comparable between dairies located within the region. As a relatively simple and mature technology, future equipment and development costs for anaerobic digester systems are not expected to change substantially. Future technological improvements are expected to be predominantly incremental. Therefore, while digester system construction costs will represent a secondary factor in determining the economic feasibility of manure digester systems, this cost factor is expected to remain relatively constant and therefore represents a minor economic driver.

Operating and maintenance costs for digester systems remain largely under-analyzed. If feasibility studies consider the system operating and maintenance costs at all, most typically attributed a percentage cost of the project’s construction cost. While improved remote sensing and automated control systems can assist digester management tasks, many industry analysts agree that most studies do not fully recognize the labor likely involved to operate digester systems (Summers, 2010).

In any case, given the comparative simplicity and mature technology used for manure digester systems, operating and maintenance costs may be expected to make a very minor contribution to the digester overall economic feasibility. Furthermore, no significant cost improvements can be expected to the anaerobic digester process that would substantially improve overall system feasibility.

On-site Heat/Boiler System

On-site heat generation from biogas is predominantly used for heated complete mix or plug flow anaerobic digester systems. Otherwise, unless major milk processing is occurring on-site, most dairy’s heating demand will be relatively limited and can be met with standard boiler systems that
can be fairly easily modified for use with biogas (although air quality compliance may be problematic). The capital cost for conversion or purchase of suitable heating systems will be relative minor. In most cases, heat generation will be limited and only a secondary use for dairies of any produced biogas. Therefore, heating use of biogas will have a very minor influence on the digester’s economic feasibility. Furthermore, no major technological improvement or future significant cost savings can be expected related to biogas heating systems that would improve overall system feasibility.

If on-site electrical generation with biogas is planned, combined heat and power (CHP) designs typically can offer cost effective opportunities to use thermal energy that would otherwise be lost. However, given most farm’s limited heating needs it likely that surplus heat would still be generated. Consequently, while their may be opportunities for cost effective efficiency gains, the magnitude of the economic benefits will remain minor and will not be expected to be a significant economic driver of system feasibility.

**On-site Electrical Generation**

As discussed above, on-site electrical generation has generally been the primary use of biogas produced by on farm digester systems. Except for the Vintage Dairies facility which is producing biomethane for pipeline injection, all the other manure digester systems operating in California are using their biogas production to produce electricity on site. Electrical generation with internal combustion (IC) engines is a very well established technology that can be applied at both the full range of production scales and under a wide variety of operating conditions. Generally speaking, outside California, electrical production with internal combustion engines can be cost effectively performed. Operating under less stringent air quality emission requirements, dairy digesters in other states are able to generate surplus electrical energy which typically can be sold to their local electrical utilities under net-metering arrangements.

The national average on-site electrical usage for dairies is 550 kW / cow / year (Barker, 2001). At a typical retail energy cost of $0.12 kWh, the annual electrical cost for each dairy cow would be $66. If it is conservatively projected that each dairy cow can generate 0.1 kW, then an annual basis total value of the potential electrical production would be 876 kWhr/cow/year which would be worth approximately $105 per year per cow of which approximately $39 per year would be the potential value of the surplus electricity at average retail electricity prices.

Yearly operation and maintenance costs for electrical generation systems are typically estimated to be in the range of $0.015/kWh (Jewell et al., 1997; Hurley, 2007) which reduces the system operator net revenues/saving.

However, as discussed in more detail below, future electrical generation with biogas at dairies within the Central Valley is highly problematic due to recent air quality regulations that prohibit IC engine use unless NOx emissions can be reduced to 9 – 11 ppm or less. It is currently unclear

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31 Hilarides Dairy also produces compressed biomethane with some of its digester biogas for use as a biofuel by its specially converted trucks.

32 Although as discussed under the Electricity price section, under the net metering program additional tariff costs for transmission and distribution, as well as demand charges may also be incurred. In addition, the interconnection process prescribed by CPUC Rule 21 can also require additional costs to the dairy.
whether the use of on-site electrical generation equipment can be cost-effectively applied in the near term for dairy digester systems in the Central Valley.

On-site generation of electrical power is an important potential use option for dairy digester biogas/biomethane. As a form of distributed power, such on-site systems offer possible direct economic benefits and reduced overall environment impacts. However, given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically infeasible in the Central Valley based on current electricity prices until major improvements in the technical capabilities and costs for new microturbines or fuel cells are achieved.

**Biogas Upgrading**

The fundamental purpose of biogas upgrading is to increase the proportion of methane from its 50 to 65% concentration to near pure methane (95-99%) while removing the corrosive H$_2$S and CO$_2$ impurities.

The specific gas quality standards for biomethane to be accepted into the PG&E natural gas system are set in PG&E Gas Rule 21.C and by Rule 30 requirements for SoCalGas.33 Key utility specifications include less than 1% CO$_2$ and 4 ppm of H$_2$S content.

The upgrading requirements for biomethane production to pipeline injection standards are comparable (and typically higher) than those required for CBM or LBM production. Therefore the primary economic differentiators between biomethane uses (e.g., pipeline injection, compressed biomethane or liquefied biomethane) will be associated with subsequent delivery and market requirements for the different uses.

There are three main processes necessary for refining biogas into biomethane. The technologies for each of the procedures are well established and widely used but generally are implemented at a scale far larger than the production levels that even large dairy digesters would be able to attain based on their own herd size.

**Scrubbing (H$_2$S removal)**

Hydrogen sulfide (H$_2$S) is a highly corrosive impurity within biogas as it readily combines with water to form sulfuric acid. Generally, H$_2$S concentrations in raw biogas are typically 0.5% or less and can be problematic for many gas uses. However, for “lower tech” applications (such as boiler systems or internal combustion engines) regular and increased maintenance can be used to cost effectively manage most of the potential corrosion effects. Various methods are used to remove H$_2$S from the digester gas. New low-cost options are being developed and the lowest cost option for the end-use clean-up requirements will generally be selected. Removal by iron sponge is one of the most effective techniques, but it is more costly than some of the less effective removal processes that may still met the end-use requirements for H$_2$S concentrations in the gas.

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33 Gas quality specifications for the delivery of gas into the PG&E utility system are available at:  
SoCalGas’ system requirements are available at:  
Conditioning
Water removal from biogas is a relatively straightforward and can be achieved through refrigeration of the biogas to condense out the water content. Using a relatively inexpensive commercial refrigeration unit and minor parasitic energy loss (2%) the water content in the biogas can be adequately reduced to acceptable levels.

Carbon dioxide is the most critical and expensive impurity to remove from biogas. Due to its relatively inert chemical composition and high concentration levels within the digester biogas, more extensive gas treatment is necessary for carbon dioxide removal. Water scrubbing is a relatively simple and low cost conditioning that is considered suitable for on-site dairy use. Although less efficient than other “higher tech” approaches, water scrubbing is most environmentally benign. Alternatively pressure swing adsorption (PSA), amine scrubbing and other technologies are available which offer some advantages for some applications (e.g., compatibility with LBM ) but also present cost or environment byproduct disadvantages.

Biogas upgrading is likely necessary for any off-site use of digester biogas. The processing equipment, and to a lesser extent, the operating and maintenance costs, required for biomethane production will add considerable cost to the digester system. In addition, approximately 15% of the methane content is lost during the upgrading process. As a result, the unit cost for the biomethane will be increased substantially. While increasing the size of production levels can help to lower the unit cost of production, the volume of production necessary for most applications of the scrubbing and conditioning equipment remain relatively high due to the fixed cost of the technology. Furthermore, diseconomies of scale may begin to be incurred if the digesters can not be favorably located and clustered. Several previous feasibility studies have suggested that biogas upgrading systems would need to process the biogas of 10,000 cows although other suggest that full production cost efficiencies for pipeline injection would require 30,000 cows (Goodman, 2010).

As a result, unless future technology improvements can cost-effectively scale down biogas upgrading systems, it is likely that current biogas upgrading technology requirements will remain a major factor restricting economic feasibility.

Distribution / Transmission System
The construction costs for biomethane pipelines can vary considerably. Typically pipeline costs are estimated to range from $100,000 to $250,000 per mile. In addition, land acquisition or right-of-way purchases may also be necessary. While the operating cost for pipeline delivery will generally be very low, the initial construction will represent a significant additional investment cost – especially compared to tanker truck delivery. Given the comparatively high cost for pipeline delivery, it has generally been judged that pipeline delivery of biomethane for any significant distance will not be economically feasible. Some analysts suggest that at most one or two miles in most cases would be a limiting distance for pipeline use (Krich, 2005). Others maintain that up to five miles may be viable under certain conditions (Brennan, 2010).34

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34 PVC like pipe materials are also available for raw biogas transmission. However, as an even lower-grade and less valuable fuel it is will be less economically feasible to transport than the refined biomethane.
Pipeline distribution costs also will play a fundamental role determining the feasibility of a centralized biogas treatment facility serving several dairy digester systems. Cost effective development of a centralized biogas treatment facility will require the farms’ digester systems to be clustered close together. Furthermore, the combined biogas production must be sufficient to ensure an adequate supply to attain the necessary economies of scale for cost-effective biogas upgrading. Otherwise, the pipeline transmission costs to import the additional biogas from more distant producers may place additional cost burdens that undermine the collective enterprise’s overall feasibility.

CBM and LBM production will require both storage and truck transfer facilities. Standard and relatively inexpensive propane tanks can be used for low pressure biomethane storage (i.e., up to 300 p.s.i.). This is most suitable as intermediate storage of the biomethane output from the upgrading facility. Biomethane must be further compressed to 3,000 to 3,600 p.s.i. (i.e., equivalent to CNG pressure) for delivery and use as a transportation fuel. LBM has to be liquefied at pressures of over 5,000 p.s.i and maintained at low temperatures. Such high pressure storage is expensive and relatively complex to maintain. For pipeline injection of biomethane, only limited on-site gas storage facilities are necessary.

**Pipeline Injection**

Currently, although California utilities are willing and able to purchase biomethane produced by manure digesters, the supplying dairy must provide all the facilities necessary to deliver pipeline quality biomethane to the utility’s natural gas transmission system. The project developer is responsible for all costs of the injection project. Furthermore, the dairy (or third-party developer) must also perform the scrubbing and compression of the biomethane. PG&E will install and operate the metering equipment and perform the pipeline tap (Brennan, 2010). In addition, proximity to the natural gas transmission line will also be a major limiting factor. As discussed earlier, pipeline delivery costs will likely ensure that any biogas/biomethane production facilities for pipeline injection will have to be located at most a few miles from suitable connection locations to the transmission line.

Gas quality testing costs are a large expense associated with renewable gas projects and must be paid by the project developer. These costs include: (i) initial research into untested co-digestion feedstocks; (ii) physical testing and verification at project start-up; and (iii) ongoing monthly physical gas quality testing. The cost of testing increases as the complexity of the feedstock increases. PG&E has already tested and may accept dairy manure-based biomethane into its pipelines. Research must be done on a per farm basis that considers variables such as the cattle feed, hormones, pharmaceuticals, and chemicals used at each dairy (Brennan, 2010).

Biomethane producers injecting biomethane into the existing natural gas transmission pipeline will also incur an interconnection cost that will vary depending on the utilities being served. Recent estimates for the connection cost for biomethane injection into PG&E transmission system are $0.4 to $0.6 million depending on the size of the facilities required at the interconnection. SoCalGas will charge biomethane producers the same rates as those for a tradition natural gas interconnection.

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35 In 2008, SoCalGas and SDG&E requested CPUC permission to allow biomethane project interconnection costs to be recovered from all ratepayers. The CPUC denied this request without prejudice on procedural grounds in Resolution G-3420. The utilities may file an application for further CPUC consideration of this proposal.
Projects injecting up to 1 MM cu.ft. / day will pay approximately $0.8 million to access the SoCalGas transmission system (Anders, 2007).

The connection costs for pipeline injection are considerable and will require a greater scale of production so that the added costs can be adequately distributed to result in a manageable unit cost basis. In any case, the utility connection costs will represent a significant factor reducing the potential economic feasibility of biomethane production from dairy digesters. Furthermore, pipeline injection use of digester biomethane will be geographically constrained due to the high cost for any pipeline of the biomethane between the digester and suitable injection points which must be along the natural gas transmission system.

**Compression / Liquefaction**

Methane requires 5,000 psi for liquefaction and approximately 600 psi for transmission pipeline injection, and it requires major applied energy to attain such pressures. Compression of biomethane only to 1,000 psi requires approximately 207 Btu of energy to compress each 1,000 Btu – a considerable parasitic energy “loss” or cost of 20.8 percent (Hansen, 1998), in addition to methane lost during earlier stage of the conditioning process. This does not include efficiency losses associated with the compression engines themselves.

There are major scale constraints for liquefaction and distribution of biomethane. Due to the cryogenic nature of liquid biomethane, significant energy must be used to maintain the produced LBM at very low temperatures to avoid the liquid “boiling off.” The potential energy losses for storage of LBM can be significant. Therefore, industry analysts suggest that liquefaction facilities should at a minimum be sized to produce adequate LBM to fill a standard tanker truck (approximately 10,000 gallons) every three or four days to reduce on-site storage losses.

**Biomethane for Fuel Use and Conversion Costs**

In recent years, the State of California has conducted extensive analyses and taken several actions intended to encourage the development of alternative vehicle fuels including Executive Order S-06-06 and most recently Executive Order S-01-07 (the Low Carbon Fuel Standard) requiring a 10 percent reduction in the carbon intensity of transportation fuels by 2020. Currently, compressed natural gas (CNG) is used as a petroleum alternative for cars and other light use vehicles. In addition, liquefied natural gas (LNG) is also being developed as a fuel source suitable for heavier industrial vehicles. While new CNG and LNG vehicles are available for commercial purchase, the existing market is relatively small and these alternative fuel vehicles are more costly. In addition, some diesel and other vehicles can be retrofitted to use a natural gas fuel. However, the costs are considerable and even high-use vehicles will have a long payback period from an economic feasibility perspective.

Compressed biomethane (CBM) and liquefied biomethane (LBM) are both potential substitute fuels for CNG and LNG vehicles. However, as with the CNG and LNG markets, although demand has been growing, this alternative fuels market is still at an early stage of development. Currently the majority of CNG and LNG vehicle fleets belong to municipalities. While this may offer some opportunities for partnerships, these will be geographically limited and will have a very finite demand
1. Key Factors Determining Economic Feasibility

Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities in the Central Valley of California May 2011

until wider public adoption of CNG or LNG occurs. In addition, greater adoption of CNG and LNG as alternative fuels also faces strong competition from ethanol and biodiesel, which to date have received considerable and greater federal and state support.

Currently, nearly all of the LNG within California is imported over land in its liquid form by truck. Therefore, until planned LNG terminals in Southern California are completed, LBM produced in the Central Valley could have a transportation advantage over LNG. However, it is unclear whether the magnitude of this transportation cost savings will outweigh the higher production costs currently projected for LBM.

Consequently, the market potential for CBM and LBM is far from assured and participation as a fuel provider will face additional production costs (vehicle conversion, possible development of on-site fueling infrastructure). Therefore, given the absence of clear market demand and purchasers, the feasibility of production of CBM or LBM for bio-fuel sale is uncertain since it is difficult to determine the likely market price that producers would actually be able to obtain.

Overall Digester System Construction Cost Estimates

As discussed above, the capital costs for manure digester systems’ construction and equipment costs will vary depending on both the size and configuration of the planned system. Irrespective, even the simplest of manure digester systems are relatively costly. Table 1-2 shows the costs and grant funding obtained for nine dairy digester systems in California. The cost estimates include the electrical generation facilities.36

**TABLE 1-2**  
**CAPITAL COSTS FOR DAIRY DIGESTER DEVELOPMENTS IN CALIFORNIA**

<table>
<thead>
<tr>
<th>Dairy</th>
<th>Digester Type</th>
<th>Size (kW)</th>
<th>Annual Energy Production (MWh)</th>
<th>Debt</th>
<th>Capitalization</th>
<th>Grant</th>
<th>Equity</th>
<th>Capital Cost (a)</th>
<th>Capital Cost (a) ($/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hilarides</td>
<td>Covered Lagoon</td>
<td>500</td>
<td>3,383</td>
<td>0%</td>
<td>40%</td>
<td>60%</td>
<td>$1,392,000</td>
<td>$2,785</td>
<td></td>
</tr>
<tr>
<td>Cottonwood</td>
<td>Covered Lagoon</td>
<td>300</td>
<td>2,133</td>
<td>0%</td>
<td>31%</td>
<td>69%</td>
<td>$3,132,000</td>
<td>$10,441</td>
<td></td>
</tr>
<tr>
<td>Blakes Landing</td>
<td>Covered Lagoon</td>
<td>75</td>
<td>253</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
<td>$392,000</td>
<td>$5,229</td>
<td></td>
</tr>
<tr>
<td>Castelanelli</td>
<td>Covered Lagoon</td>
<td>160</td>
<td>1,135</td>
<td>0%</td>
<td>57%</td>
<td>43%</td>
<td>$1,123,000</td>
<td>$7,016</td>
<td></td>
</tr>
<tr>
<td>Koetsier</td>
<td>Plug Flow</td>
<td>260</td>
<td>540</td>
<td>0%</td>
<td>0%</td>
<td>100%</td>
<td>(a)</td>
<td>$1,537,000</td>
<td>$5,911</td>
</tr>
<tr>
<td>Van Ommering</td>
<td>Plug Flow</td>
<td>130</td>
<td>489</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
<td>$973,000</td>
<td>$7,488</td>
<td></td>
</tr>
<tr>
<td>Meadowbrook</td>
<td>Plug Flow</td>
<td>160</td>
<td>1,100</td>
<td>0%</td>
<td>45%</td>
<td>55%</td>
<td>$1,185,000</td>
<td>$7,405</td>
<td></td>
</tr>
<tr>
<td>IEUA</td>
<td>Modified Mix</td>
<td>943</td>
<td>7,572</td>
<td>0%</td>
<td>1%</td>
<td>99%</td>
<td>(a)</td>
<td>$14,543,000</td>
<td>$15,422</td>
</tr>
<tr>
<td>Eden-Vale</td>
<td>Plug Flow</td>
<td>180</td>
<td>457</td>
<td>0%</td>
<td>37%</td>
<td>63%</td>
<td>$904,000</td>
<td>$5,021</td>
<td></td>
</tr>
</tbody>
</table>

a Capital Costs have been adjusted for inflation into 2010 dollar terms.

b Koetsier and IEUA received their subsidies as 5 year production payment instead of grant funding.


36 As discussed earlier, new digester development for electrical production will incur substantially higher equipment costs as more expensive generation system are now required to meet subsequent and more stringent air quality standards limiting NOx emission to 9ppm.
Other studies report similar cost estimates for developing dairy digester systems. Recent analysis for comparably sized dairy digester systems in Vermont reported capital costs between $4,000 to $7,800 per kW in 2010 dollar terms (Dowds, 2009). Similarly, the approximate initial total cost for developing a 400kW digester system at Fiscalini Farms in Modesto California was reported to be over $2 million, equivalent to more than $5,000 per kW in 2010 dollar terms (Gannon, 2008). However, subsequent additional design and development requirements resulted in a final system cost of approximately $4 million of which only $1.4 million was obtained from grant funding (Dairy Today, 2010). The Gallo Farms Dairy estimates that the cost of its 700 kW digester system was approximately $3.5 million in 2010 dollar terms which is equivalent to a $5,000 per kW capital cost (Pacific CHP Application Center, 2010).

As discussed above, digester systems developed for production of biomethane will require considerable additional upgrading equipment to remove the CO₂ and other impurities. In addition, compressor and storage systems will be needed if liquefied or compressed biomethane is to be produced. If the upgraded biomethane is to be injected to the utility pipeline then pipeline injection may require additional on farm (and possibly off-farm) pipeline to the utility’s natural gas transmission line as well as interconnection, controls and monitoring facilities to ensure the quality of gas supplied to the utility.

As discussed previously, most current biogas upgrading systems require relatively high gas throughput volumes for optimal performance. Consequently, biomethane production will incur additional costs from both increased scale of production as well as the additional facility and equipment requirements. Industry experts currently maintain that at a minimum manure for 10,000 cows would likely be necessary (without co-digestion) to generate sufficient biogas to supply a biogas upgrade facility to operate efficiently. While dairy farms would not need to invest in electrical generation systems, there would nonetheless be major additional cost for farm-sized biomethane production. Preliminary cost estimates for the CEC project interconnection costs of $250,000 and pipeline costs of at least $50,000 for the existing California digesters (PERI, 2009). The cost for biogas upgrading facilities was estimated to vary from $400,000 to over $750,000 (depending on the plant capacity) for the existing digester systems. The saving from the reduced electrical generation capital cost also varied greatly from as high as $800,000 for Hilarides Dairy to just under a $100,000 for other dairies. Excluding the Blakes Landing and Castelanelli Dairies which were 5 miles or further from a suitable utility connection site, the total net additional capital cost for pipeline injections was generally $500,000 to $700,000 higher than for on-site electrical generation (PEIR, 2009). The study also projected that there would be a 15 percent loss of the original biogas quantity by the upgrading process.

Although preliminary and specific to the existing digester systems, the PERI cost analysis demonstrates the considerable additional capital cost involved in dairy digester development for biomethane production.

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37 For farms located five miles from a suitable transmission utility connection site the pipeline cost was $1 million.
38 Facility costs for biogas conversion to biomethane at pipeline injection quantities will be considerably higher and likely in the range of at least $3.5 to $4 million (not including utility interconnection costs or the digester facilities).
39 Except for Hilarides Dairy which had an unexplained but very major cost saving (approximately $788,000 in 2007 dollars terms) for replacement of its electricity generation equipment.
Implementation Factors

Farmer Interest
Dairy production is the core business for dairy farm owners most of whom also must manage some feed-crop production on their farms. Modern dairy farm management is itself a complex business requiring considerable time and expertise to successfully manage milk production and maintain regulatory compliance. This is particularly true during recent years as a poor national economy has adversely affected the California Dairy industry. Although 2008 was a year of record production with high milk prices, in the first half of 2009 dairy producers faced increased production costs – partly from increased feed costs resulting from reduced production as many Midwestern crop farmers shifted their production to feedstock crops for bio-ethanol production. For the first quarter of 2009, the average cost of production for California dairy farmers was $18.51 / cwt. More importantly, as a result of overproduction and reduced foreign demand, milk prices fell by early 40 percent between 2008 and 2009 to $10.47 / cwt - their lowest level since June 2003.

Furthermore, feed expenses represent the majority of the dairy farmer’s cost. In 2005, nearly 58 percent of the average Californian dairy farmer’s total cost of production was spent on feed while less than 3 percent of the total dairy budget was spent on electricity, fuel and lubrications for the farm operations (USDA, 2005). Consequently, the potential direct energy and/or fuel cost savings from a digester will represent, at best, a very minor benefit to the farm’s budget and any such savings may be easily outweighed by any feed price changes.

Not only must dairy farmers be willing to accept the necessary investment and operating risk to develop digester systems, farmers must develop the technical capabilities and have sufficient professional interest in assuming the secondary occupation of biogas production (Sempra, 2009).

In the face of such volatility and adverse economic conditions, without clearly attainable net financial earnings, few dairy farmers may be expected to assume the additional costs, risks and responsibilities necessary to develop dairy digesters.

Capital Availability
The interest rate associated with the initial capital investment (and to a lesser extent managing the operations cash flow needs) will play an important role in determining digester feasibility. Low interest loans and favorable tax depreciation allowances can have an important contribution in reducing the loan repayment burden that a facility must support.

The useful project life for digester systems will have an important role in affecting the economic feasibility of proposed digester and related biogas treatment facilities. A longer useful life will increase the period over which the facility’s capital investment can be earned back. However, due to the interest and inflation effects to the capital investment, future earnings at later periods in a facility’s operations typically will have a lesser contribution to offsetting the initial capital investment.
There are two key factors determining the availability of capital for farm digester systems. First, the dairy farm’s financial situation will be a fundamental determinant of its ability to borrow capital. The amount of equity that a dairy has in its business, its cash flow and the amount of the loan required will determine the likelihood that the farmer can qualify for a loan. Given the recent financial challenges facing the Californian dairy industry, it is expected that few dairies will be able to qualify for the necessary loans from commercial banks to fund the development of major digester facilities. Even those that could qualify may prefer to maintain their available borrowing capacity rather than pursue digester system development.

In addition to the dairy’s financial position, commercial banks must also be willing to provide the loans. Given the currently tight credit market facing the entire economy and the dairy industry’s current poor market conditions, it may be expected that many banks will be unwilling to provide lending for digesters – especially under relatively favorable terms.

Therefore, due to the challenges facing the dairy industry and the generally weak credit market, few dairies are expected to be in the financial position to fund digester development.

**Third Party Developer Assistance**

Third party developers can be expected to be important for the development of future on-farm or community digester facilities within the Central Valley. As discussed above, most dairy farmers are likely to be unwilling or unable to develop manure digesters systems themselves. Third party developers will likely be better able to collect and manage the investment and have the expertise necessary for effective digester development. The ability for third party developers to negotiate and manage favorable Small Renewable Generator Power Purchase Agreements (PPAs) with utility companies is also likely to be a key advantage for future digester system development.

The commercial interest rates and the related return on investment (ROI) sought by private developers will be important determinants of the economic viability and future development of digester facilities in the Central Valley. The ROI that developers will apply to digester systems will be a function of both commercial interest rates and the profit and risk premiums associated with any digester facility venture. The risk facing developers can be reduced by favorable market conditions (e.g., long term contracts with utilities or other biogas/biomethane consumers) and will also be related the supply conditions (such as the extent that the production technology and equipment is well established, widely adopted and/or transferrable to other commercial uses).

Due to the technological, market and regulatory risks associated with biogas/biomethane production, the returns on investment that potential venture capitalist or other third party developer will seek from any digester investment will initially be significantly above the returns required for other more established industries or businesses. Within the energy industry, potential investors typically seek payback periods of three to five years (Cheremisinoff, 2010; Best 2010). Within the published digester feasibility studies, the payback periods and return on investment rates applied vary considerably – partly given the differences between financial feasibility analyses (reflecting commercial investors’ profit requirements and capital terms) and economic feasibility studies (that represent agency or public policy perspectives) where the cost of money will be substantially lower and profit
earning not applicable. Recent analyses for the California Energy Commission have applied rate of return estimates of 17% for their feasibility analyses (PERI, 2008).

While third party developer participation may be an important component of widespread digester development, their participation is fundamentally a reflection of the economic feasibility of dairy manure digesters and market context. Consequently, they may be considered to play an major role but will be an indirect economic driver since it will be the fundamentals of other market conditions that will determine the role and extent of their participation in the future digester development within the Central Valley. Third party developers can structure projects that place all of the economic burdens (and most of the potential profits) with the third-party developer, but provide some financial benefits to the dairy (i.e., free solid digestate to be used for bedding) (Maas, 2010).

**Environment Compliance and Regulatory Requirements**

In general, dairy operators face increasingly stringent state environmental regulations requiring dairy operators to adopt more advanced methods to manage their operations. The requirements of Senate Bill (SB) 700, San Joaquin Valley Air Quality Management District (SJAQMD) air quality regulations and Central Valley Water Board (CVWB) waste discharge regulations are examples of such rules. Anaerobic digesters, composting systems and other more costly waste management approaches are replacing traditional land application of dairy manure as accepted manure management practices. Consequently, if the economic returns of digester systems can be improved, then their greater implementation can be encouraged, which in turn will result in overall reduced air and water quality impacts.

**Water Quality Compliance**

Until relatively recently, most dairies located within the Central Valley Water Board jurisdiction operated under a waiver of waste discharge requirements. In May 2007, the Central Valley Water Board adopted Order No. R5-2007-0035 (Waste Discharge Requirements General Order for Existing Milk Cow Dairies or Dairy General Order). The order serves as general waste discharge requirements for discharges of waste from existing milk cow dairies and requires dairies to submit a Report of Waste Discharge prior to construction of an anaerobic digester.

Compliance with water quality regulations has added costs related to monitoring and reporting. Cost to comply with water quality laws and regulations which previously may have been deferred, may be required sooner if monitoring demonstrates non-compliance. The additional water quality requirements in the order have added considerable costs and restrictions. Farmers are now required to manage their applications of nutrients to their farmlands and otherwise protect groundwater resources. The key water quality concerns for dairy digester systems are the potential for adverse groundwater impacts from dairy waste or digestate stored within dairy lagoon systems and the added salt and nitrates from the importation of co-digester feedstock. The CVWB estimates that a typical 1,000 herd dairy produces approximately 3,600 tons (dry weight) of manure per year containing 180 tons of nitrogen and 235 tons of inorganic salts (CVWB, 2007).
Under the Dairy General Order, unless landowners can demonstrate that their dairy’s specific site conditions will not result in water quality impacts, the primary compliance approach will be construction of a non-polluting lagoon system, which is a significant barrier to widespread digester development. Currently, the CVWB is in the process of completing a comprehensive salinity management program with the State Water Board to address salinity problems within the Central Valley.\(^\text{40}\) However, until the new plan and program is completed, there are no general salt standards. Consequently, review of dairy farm waste discharge compliance plans are performed on a case by case basis and the salt impacts of co-digester digestate are poorly understood, making it more difficult and costly for dairy farmers to comply with the water quality requirements.

Depending on the specific soil and groundwater conditions, and crops grown, some dairies need to reduce their application rates of liquid digestate or solid manure to comply with the state regulations. Salt accumulation issues within the Central Valley are likely to persist and there are currently limited management options for reducing the potential water quality impacts associated with accumulated salts.

**Air Quality**

The California Air Resources Board (CARB) is responsible for regulating air emissions within the state. CARB is the lead agency for implementing the AB32 Scoping Plan which is the action plan for California to reduce greenhouse gas emissions substantially by 2020 with additional reduction by 2050. The AB32 Scoping Plan identifies methane capture at large dairies as a recommended action to mitigate GHG’s.

California farms were generally exempted from air quality regulations until the enactment of SB700 in 2003, which required most dairy farmers and other large confined animal feeding operations (CAFO) to obtain air quality permits for their operations from their local air district. Although rules vary between air districts, dairies that require air permits are now generally treated like other industries.

The San Joaquin Valley Air Pollution Control District has implemented several rules that apply to dairy operations including Rule 4550 (Conservation Management Practices [CMO] Plans), and Rule 4570 (Confined Animal Facilities). In the SJVAPCD new and modified dairies are subject to the New Source Review Rule – District Rule 2201, which requires Best Available Control Technology (BACT), Public Notice, Health Risk Assessment (HRA) & Ambient Air Quality Analyses (AAQA). For the SJVAPCD to issues permits, the projects are also required to comply with the California Environmental Quality Act (CEQA).

While the dairies are adapting to the new rules, the New Source Review Rule BACT requirements for NOx and SOx emissions from electrical generation equipment are cited as a real economic challenge for the dairies. There are several approaches to electrical generation but the systems are expensive to operate and poorly suited for dairy biogas or biomethane use.

\(^{40}\) Central Valley Salinity Alternatives for Long-Term Sustainability (CV-SALTS)
The following is detailed updated information from Ramon Norman at the SJVAPCD describing the current requirements related to strict NOx emission limits (Norman, 2010).

“For projects proposing to generate power from biogas in the San Joaquin Valley, the main pollutants that the District is concerned about are NOx and SOx. This is because these pollutants are precursors to ozone (NOx) and particulate matter (NOx and SOx). The San Joaquin Valley Air basin will soon be classified as extreme non-attainment for the Federal 8-hour ozone standard (and the now revoked Federal 1-hour ozone) standard - the worst classification. The San Joaquin Valley Air basin is also classified as non-attainment for the Federal PM2.5 standard. Because of the air quality problems in the San Joaquin Valley and reductions in NOx are critical to the District’s attainment strategy, the District is now requiring more stringent emission controls (such as catalysts) for biogas-fired engines and evaluating alternative equipment (fuel cells, microturbines, etc.) to further reduce NOx emissions down to 0.15 g/bhp-hr (around 9-11 ppmvd @ 15% O2) or less as BACT for these operations. This BACT level has been in place for fossil fuel-fired engines in the District for a number of years but the District is just beginning to apply this BACT level to biogas-fired engines. To meet the District BACT for NOx from these installations, controls (catalysts) would need to be added to an engine or an alternate technology, such as microturbines or fuel cells, would need to be used. Because the San Joaquin Valley is classified as non-attainment for the Federal PM2.5 standard and SOx is an important precursor for PM2.5, emissions of SOx must also be minimized. To meet the District BACT for SOx from these installations, scrubbing of the gas to remove H2S (down to 50 ppmv) prior to combustion will also be required. Because the San Joaquin Valley Air District is classified as attainment for the CO Ambient Air Quality Standard, BACT is usually not triggered for CO and engines would only be required to meet the 2,000 ppmvd CO limit from District Rule 4702.

At a minimum, any flares proposed for a digester system would need to satisfy the "Achieved in Practice" Category in the District's BACT Guidelines, which currently require a low-NOx flare with NOx emissions ≤ 0.06 lb/MMBtu. Any flares proposed for a digester would also need to satisfy the requirements of District Rule 4311, which requires enclosed flares to meet certain NOx and VOC emission limits and to be source-tested annually. Open flares (air-assisted, steam-assisted, or non-assisted) with flare gas pressure is less than 5 psig must be operated in such a manner that meets the control device requirements of 40 CFR 60.18. Emergency flares, which are exempt from the previous previsions, are required to maintain records of the duration of flaring events, the amount of gas burned, and the nature of the emergency. The requirements of District Rule 4311 can be found at the following link:


Any boilers or process heaters proposed for a digester system and rated 5.0 MMBtu/hr or greater would need to satisfy the requirements of District Rule 4320, which requires biogas-fired units to meet a NOx emission limit of 12 ppmv @ 3% O2 and also requires periodic source testing and emission monitoring. The requirements of District Rule 4320 can be found at the following link: http://www.valleyair.org/rules/currntrules/r4320.pdf.”

Mr. Norman also provided a list of suppliers of equipment that may be able to satisfy the District’s BACT requirement for NOx from power generating equipment that combusts biogas (Norman, 2010).
Inter-Agency Co-operation and Co-ordination

Fundamentally, there is a major challenge for finding an effective mechanism and forum for facilitating inter-agency co-operation and co-ordination. The Interagency Bioenergy Working Group which is implementing the Governor's Bioenergy Action Plan is chaired by CEC Commissioner Boyd. From a comprehensive cross resource perspective, manure digesters are generally recognized to offer significant net environmental benefits. However, since these benefits extend across several resource areas (i.e., air, water and energy use) and are not fully recognized by market mechanisms (e.g., odor and greenhouse gas reductions) balancing impact tradeoffs remains difficult. Currently methane emissions from dairy operations are not regulated.

As a result, while the negative air quality impacts of the NOx emissions are recognized, the corresponding (albeit different and less localized) air quality benefits of the methane destruction are not. Furthermore, there is not an easy mechanism for valuing the societal tradeoff of the beneficial energy capture (i.e., the produced electricity) from a resource that otherwise would have its entire energy resource value lost.

The complicated regulatory environment facing dairy operators is widely considered to be a major obstacle to future anaerobic digester development within the Central Valley. Several industry participants and analyses recommend that continued CEC and CPUC support to address technical and commercial risks is important for future development of manure digester systems in the Central Valley (Dusault, 2010). Improvement to the permitting process for complex projects with cross resource impacts such as anaerobic digesters is generally recognized as important and necessary for encouraging future development of manure digesters. A centralized and stream-lined permit process that reduces the regulatory burden would greatly facilitate future dairy digester development.

Utility Cooperation

Utilities are primarily interested in the renewable energy. There is currently some mismatch between utilities interests and needs for digester development. Although there are some regulatory restrictions to utilities, there are many potential opportunities for a supportive utility role to bridge the existing market gaps and barriers to digester development. Utility participation in future projects is particularly important for the biomethane conditioning projects. Support by utilities in this early stage of market development could have a significant positive role.

Another potential benefit of utility involvement may be the utilities’ ability to exercise the right of eminent domain to acquire right-of-way needed for pipeline construction which might facilitate developer access to utility pipeline interconnection points.

Significantly streamlined (and/or if possible utility cost shared) interconnection procedures would improve the economic feasibility of digester-based gas and electricity projects. Utilities also face regulatory restrictions that limit both their involvement and, most importantly, the prices that they can pay for dairy digester energy. Nevertheless, innovative and constructive partnerships between digesters and utilities could offer a key potential mechanism for greater and more cost-effective development of biogas as a renewable resource. Several experts suggested that the market for future biogas conversion to biomethane would be improved if utilities such as PG&E were willing to
invest, operate and maintain the necessary upgrading facilities required for pipeline injection. SoCalGas is investigating the feasibility of potential cooperation and involvement in future biomethane production projects for pipeline injection with Sempra Energy (Goodman, 2010).

Such an approach would reduce the technical and investment burden on third party or dairy digester owners. However, the significant production costs for pipeline injection would remain high as only minimal savings would be potentially gained by reducing the utility’s need for verification of the non-utility injected biomethane quality. In addition, the geographic constraints of biogas acquisition in relative proximity to the utility transmission system would also remain. While the utility companies may be interested in facilitating the development of a biomethane injection and developing a market for biomethane industry, gas production is not a core business for California utilities. Consequently, the utilities are unlikely to undertake greater involvement in digester development when third party developers with greater technical experience can be expected to pursue digester development and there are adequate and cost-effective alternative projects for the utilities to meet their RPS requirements.

Under the current market and regulatory conditions, there is little incentive for PG&E or other utilities to assume the additional costs, risks and responsibilities. Furthermore, regulatory changes and CPUC approval would be necessary for PG&E to undertake any such biogas development projects and pass on the costs to ratepayers.

**Emerging Technologies and Market**

As discussed above, the economic viability of future digester development appears currently to be primarily constrained by the comparatively low commodity prices for natural gas and electricity coupled by the relatively high costs of production. The complicated and cross resource impacts associated with dairy digester systems result in costly compliance requirements. Unless major breakthrough technological improvements are achieved, it is considered likely that manure digester production will remain economically unfeasible without government support for the foreseeable future. Furthermore, future improvements in feasibility would be expected to be minimal and incremental as long as natural gas and electrical prices remain relatively stable in real terms.

There is considerable hope within the renewable resource industry that fuel cells, “micro-scrubbers,” or other new technological improvements may be possible that could reduce unit production costs for biogas and/or biomethane production or enable affordable on-site electrical production that complies with air quality requirements.

Similarly, the economic feasibility for biogas production is presently reduced by the currently limited market for CBM and LBM as a transportation biofuel. Major growth in commercial and/or consumer natural gas vehicles (and the necessary related fueling infrastructure) would likely represent a new market and demand for CBM and/or LBM. In which case, dairy manure production of CBM and/or LBM might be able to take advantage of some comparative advantage of local production (especially over LBM which is currently mostly imported into California at some cost either by road or rail). However, until these biofuel markets develop or other major technical advances actually occur, the

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41 It is likely that the utility would nonetheless need to evaluate biogas quality
42 However, successful development of the proposed Clearwater and/or Port Esperanza LNG terminals in Southern California would be expected to reduce the potential locational advantage for future LBM production.
economic feasibility of dairy manure digesters can be expected to remain difficult without adequate governmental and/or regulatory assistance.

**Analysis Caveats**

The previous economic assessment is based on research and interviews during a highly dynamic period for the digester and other renewable energy industries. As outlined above, there are many unknown variables facing the industry – both technological and regulatory. Consequently, quantitative analysis of the industry economics is particularly challenging and, if imbedded assumptions or factors are not recognized, any finding can be misleading or highly prone to misinterpretation.

Furthermore, most digester analyses are very site and technology-specific. In addition, most operating digester projects have been pilot or demonstration projects that have received considerable government assistance. As a result, there is extensive complexity associated with any efforts to normalize the design, costs and performance of digesters operating under very different circumstances.

Consequently, we have used a predominantly qualitative approach since the primary purpose for this economic assessment has been to provide a framework by which the key economic drivers can be distinguished from the numerous variables and other factors that have a more indirect and lesser contribution to dairy digester feasibility.

### 1.5 References


CH2M Hill, Making Renewables Part of an Affordable and Diverse Electric System in California, 2007.


Clear Horizons, Craven Brothers Farm Digester Project Feasibility Study, January 2006.


1. Key Factors Determining Economic Feasibility


LaMendola, T. Personal Communication, April 2010.


Maas, Kevin (Farm Power Northwest), Personal Communications, May, 2010.


Norman, Ramon, Air Quality Engineer, email to Tim Morgan at ESA, February 4, 2010.


Report 2
Economic Feasibility Model Approach
REPORT 2
Economic Feasibility Model Approach

2.1 Introduction

This report identifies the economic model and approach that will be used to evaluate the general economic feasibility of dairy manure digesters and co-digesters development in the California Central Valley. The economic feasibility considers the general costs and potential revenues under current economic conditions for digester and co-digester development. This analysis aims to provide a general assessment of the economic feasibility of various digester configurations likely to be used at dairies and farms in the Central Valley of California and to identify and evaluate the contribution and effects that the principal cost, revenue and financial parameters will have on the potential for future digester development.

The economic feasibility for specific systems will depend not only on the general and underlying feasibility factors discussed below but may also be importantly influenced by site- or system-specific considerations. A more detailed evaluation of an individual project’s feasibility would involve more specific and comprehensive determination of the revenues and expenditures for a fully-defined and site specified project. Furthermore, a comprehensive feasibility analysis might also consider the project’s overall financial cash-flow and include greater characterization of applicable market conditions and other business considerations – primarily from the perspective of the potential owner/investor.1

Nonetheless, important fundamental observations can be identified and assessed from a more general assessment approach. Economic feasibility modeling and analysis is generally best applied as an analytic tool for comparing different project configurations (i.e., size and type of facilities). Due to the large number of variables and site-specific factors that determine any specific project’s actual financial performance, this economic model cannot (and should not) be expected to represent a specific project’s financial performance. Instead, it is more appropriate to view the economic model as a framework for identifying and assessing the roles and relationships of key project factors.

The economic model will be run to assess the economic feasibility of four digester system configurations selected for relevance to reflect both current production/technology conditions as well as current market conditions for both dairy producers and potential biogas/biomethane consumers. The four generalized digester system configurations are discussed in detail in the

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1 “Economic feasibility” and “financial feasibility” are often used interchangeably by many analyses. However, more precisely and for this analysis, the term “economic” represents a more general and broader evaluation perspective distinct from “financial” which indicates a narrower and case-specific focus on a project’s monetary performance.
Proposed System Configurations to be Analyzed section below. Once the model runs are complete, the results and findings of the economic model runs of the four proposed system configurations will be included in a follow-up Economic Analysis Findings report.

2.2 Economic Model

The economic model determines the Internal Rate of Return (IRR) for a digester developer based on the expected cost and revenue performance of “prototypical” digester systems (including the necessary biogas treatment and/or energy generation equipment). The IRR represents the financial return on the developer’s equity investment in the project. The IRR is equivalent to the annual interest earned on the investor’s capital investment. It represents the total overall earnings that the investor would make and it provides a measure of the investment risk and the “cost of capital” (i.e., the earning that could otherwise be earned by other investments). If the IRR is too low, then the developer would be unlikely to invest in the proposed project since they can expect higher earnings from other uses of their capital investment.

There are four basic components to the economic model: (1) system productivity assumptions; (2) revenue projections; (3) cost of production estimates; and (4) applicable financial parameters. The general model approach and its components are presented and discussed briefly below. The specific model inputs applied under each of the analyzed development configurations are identified in the subsequent Economic Analysis Findings report.

The economic model is fundamentally a simplified cash-flow model based on California Biomass Collaborative’s Generalized Revenue Requirements Model (BC Model) and on-going research by Joshua Rapport at U.C. Davis (Rapport, 2009). The BC Model has been adapted and simplified for the economic model to focus on the role and inter-relationships of the principal factors influencing the economic feasibility of each development configuration. Limiting the input variables and utilizing simpler and more general system descriptions facilitates understanding of the key feasibility issues. This approach also enables general comparisons amongst the various system configurations by using similar system scale and financial assumptions whenever appropriate.

The economic model projects the annual revenues for the digester system based on the expected production rates and values of the system’s various outputs. The model identifies the fixed capital expenditures incurred before the first year of operation as well as the subsequent additional costs required to maintain operations. Prior to the project’s first year of operations, the cash flow is assumed to consist only of the equity investment. For each subsequent year, the operating costs are escalated at a fixed inflation rate and subtracted from the annual revenues, which were also escalated at the same rate, to calculate the net cash-flow revenues for the project.

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2 The Internal Rate of Return represents the economic gain (usually net revenue or profit) as a percentage of the capital investment used to generate it. A project’s expected rate of return is generally compared with its cost of capital (usually loan interest rate or discount rate) to determine if development is advisable.

3 In cases where future revenues were not expected to appreciate (i.e., fixed contracts), the annual revenue input to the model was adjusted accordingly to accurately represent the system’s total revenues over the entire life of the project.
Fixed annual loan payments and taxes were then subtracted from the cash-flow, to determine the after-tax cash flow. Taxes were calculated as a percentage of the taxable income (i.e. the net cash flow minus depreciation of capital and interest paid on debt). Each year’s after-tax cash flow was discounted at the Target IRR and summed to determine the Net Present Value\(^4\) (NPV) of the project’s annual earnings. An iterative method was used to find the amount of revenue required for the NPV to equal zero, thus yielding an IRR equal to the Target IRR. The amount of revenue generated by the project was compared with the revenue requirement to determine whether or under what conditions the project would generate sufficient revenue to meet the Target IRR.

Investors often require different rates of return on their investments depending upon prevailing economic conditions, the perceived risk associated with the investment, and the investors’ own risk tolerance. Therefore, investors typically decide whether or not to make an investment by comparing their own Minimum Acceptable Rate of Return\(^5\) (MARR) against the potential rate of return for a project. However, it is also instructive to assume a rate of return that will be likely to attract investment in the project, and then determine what conditions will be necessary for the project to generate that rate of return. The model calculates the financial performance of the project under a set of assumed financial and performance conditions, but it can also be used to analyze the financial conditions and performance necessary to generate sustainable project investment.

**System Productivity**

The efficiency and effectiveness of the digester’s conversion of manure (and other feedstocks in co-digestion scenarios) to biogas is a central factor in determining economic feasibility. The amount of electricity, heat and/or biomethane that can be generated by the project will determine the revenues that the project can earn. In addition, the type and quantity of other digester co-products (e.g. solid and liquid fertilizers) will likely add additional project revenues. All else being equal, greater biogas production will increase the system’s revenue potential and hence cost-effectiveness.

Currently, on-site electricity generation is the predominant use of the biogas produced at dairies in California. Heat is also produced and captured either as part of a combined heat and power system (CHP) or by a dedicated boiler system. Some of the captured heat can be used to maintain higher temperatures in the anaerobic digestion processes, which can improve biogas production efficiency. However, heat is often produced in excess of what is needed by the digester and other on-farm activities. Therefore, unless there are large nearby industrial heat demands, most of the generated heat will not be used. Consequently, the base scenario analyzed by the model does not include heat as a revenue stream, but the energy consumed to heat the digesters is similarly not included as a cost. Electricity consumed by the digester will be embedded in the electricity generation rate used to calculate the dairy digester’s productivity.

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4 Net Present Value (NPV) is value of a project’s future net cash flows minus the initial investment adjusted into current dollar terms (i.e. adjusted for inflation/time value of money).

5 MARR is the Minimum Internal Rate of Return (IRR) that a developer may be expected to require to proceed with project development.
Alternatively, biogas can be upgraded to biomethane for either pipeline injection or conversion to Liquified Biomethane Gas (LBG) or Compressed Biomethane Gas (CBG). LBG and CBG can be used as a transportation fuel either on or off-site. Due to its much higher energy density, LBG is generally the preferred form for transportation or storage. However, LBG must be kept at very low temperatures and therefore its transportation and storage require larger scale applications than CBG to achieve adequate economies of scale.

Table 2-1 provides per cow production assumptions for an average dairy digester systems operating in the Central Valley. The biogas and byproduct production quantities are combined in the Economic Model with projected resource values to determine the digester’s revenue potential.

**TABLE 2-1**

<table>
<thead>
<tr>
<th>Production Measure</th>
<th>Units</th>
<th>Per Cow per Day</th>
<th>Per Cow per Year</th>
<th>Notes (Sources)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manure Weight</td>
<td>(lbs)</td>
<td>150</td>
<td>54,750</td>
<td>Raw manure as produced by the animal (ASABE, 2005)</td>
</tr>
<tr>
<td>Water Content</td>
<td>(lbs)</td>
<td>130.5</td>
<td>47,632</td>
<td>(ASABE, 2005)</td>
</tr>
<tr>
<td>Volatile Solids Content</td>
<td>(lbs)</td>
<td>17.0</td>
<td>6,205</td>
<td>(ASABE, 2005)</td>
</tr>
<tr>
<td>Biogas Production</td>
<td>(cubic feet)</td>
<td>47.1</td>
<td>17,192</td>
<td>(NRCS, 2007)</td>
</tr>
<tr>
<td>Methane Content</td>
<td>(cubic feet)</td>
<td>30.6</td>
<td>11,169</td>
<td>65% purity (NRCS, 2007)</td>
</tr>
<tr>
<td>Methane Weight</td>
<td>(lbs)</td>
<td>1.37</td>
<td>500</td>
<td>(NRCS, 2007)</td>
</tr>
<tr>
<td>Energy Value</td>
<td>(thousand Btu)</td>
<td>30.9</td>
<td>11,279</td>
<td>Methane energy value of 1,010 Btu/ cubic feet (EPA, 2005)</td>
</tr>
<tr>
<td>Electricity Production</td>
<td>(kWh)</td>
<td>2</td>
<td>730</td>
<td>Assuming 25% efficiency, 90% run-time so that 66.6 kWh per 1,000 cubic feet of methane (EPA, 2005)</td>
</tr>
<tr>
<td>Biogas Production</td>
<td>(cubic feet)</td>
<td>27.8</td>
<td>10,150</td>
<td>Assuming 90% methane recovery in biogas upgrading to pipeline quality levels.</td>
</tr>
<tr>
<td>Digestate (solid and liquid)</td>
<td>(lbs)</td>
<td>144</td>
<td>52,560</td>
<td>Based on the mass balance, 4% of the wet mass is converted to biogas. The rest leaves the digester as digestate. This assumes no evaporative losses.</td>
</tr>
<tr>
<td>Solid Digestate</td>
<td>(lbs)</td>
<td>61.1</td>
<td>22,292</td>
<td>Assuming 75% solids recovery efficiency in a screw press.</td>
</tr>
<tr>
<td>Liquid Digestate</td>
<td>(gal)</td>
<td>9.9</td>
<td>3,614</td>
<td>Assuming all manure enters the digester without dewatering and the moisture content of the solid digestate is 65%.</td>
</tr>
<tr>
<td>Carbon reduction for GHG credits</td>
<td>(kg/ CO₂ equivalent)</td>
<td>20.4</td>
<td>7,450</td>
<td>Assumes baseline carbon emissions from uncovered anaerobic lagoons as per the Climate Action Reserve Livestock Protocol 2009. Project emissions were calculated for a complete mix digester and rich burn IC engine, without fossil fuel use for manure or biogas transport. Does not include fossil energy offsets.</td>
</tr>
</tbody>
</table>

**Revenues**

The revenues generated by a digester are central for its economic viability. Typically, it is more difficult to project future revenues than it is to estimate future costs which are easier to specify. This is
particular true in the case of a new or emerging products and markets (e.g., such as for biomethane uses) where the potential customers and future product applications are difficult to identify and fully evaluate. Furthermore, the renewable energy sector is changing rapidly as new technologies develop, policies are implemented, and non-renewable energy prices fluctuate.

Table 2-2 shows the variety of significant revenue sources potentially available to digester developments. Representative prices are also shown in the table to provide an approximate sense of the comparative magnitude of each revenue component’s potential value. More specific revenue values are determined for each analyzed digester configurations as appropriate for their circumstances. Each digester configuration’s total revenues will also be determined based on the system’s expected productivity performance (as discussed above). The project’s energy revenues will be estimated and supplemented by the additional revenues expected from sales of the system’s other by-products.

**TABLE 2-2**

<table>
<thead>
<tr>
<th>Revenue Source</th>
<th>Unit</th>
<th>Value</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Electricity Production</td>
<td>($/kWh)</td>
<td>$0.09 to $0.20</td>
<td>Sales to utilities are subject to regulatory restrictions and approval. Value will vary depending on whether Feed-In Tariff and time-of-delivery pricing are available. On-farm use may be valued at the typically higher retail electricity price as an “avoided cost” savings.</td>
</tr>
<tr>
<td>On-Farm Use</td>
<td>($/kWh)</td>
<td>$0.09 to $0.20</td>
<td></td>
</tr>
<tr>
<td>Net Electricity Sales</td>
<td>($/kWh)</td>
<td>$0.09 to $0.20</td>
<td></td>
</tr>
<tr>
<td>Heat Production</td>
<td>($/therm)</td>
<td>$8.50</td>
<td>California 2009 industrial natural gas price (EIA) adjusted for 75% conversion efficiency. Typically, on farm heat needs are very limited and therefore heat production offers little value.</td>
</tr>
<tr>
<td>Biomethane (Pipeline Injection) (a)</td>
<td>($/1,000 cu. ft.)</td>
<td>$4.17</td>
<td>Based on 2009 California City Gate price (EIA). Sales to utilities are subject to regulatory restrictions and approval.</td>
</tr>
<tr>
<td>Renewable Energy Credits</td>
<td>($/kWh)</td>
<td>$0.02 to $0.05</td>
<td>Net revenues to producers may be reduced by administration costs.</td>
</tr>
<tr>
<td>Biogas Production Incentive Credit</td>
<td>($/mmBTU)</td>
<td>$4.27</td>
<td>Based on 2009 Biogas Production Incentive Act (inflates annually).</td>
</tr>
<tr>
<td>GHG Credits</td>
<td>($/ton CO₂ equivalent)</td>
<td>$11</td>
<td>Based on 2010 ClimateSmart rates. Net revenues to producers may be reduced by administration costs.</td>
</tr>
<tr>
<td>Solid Digestate</td>
<td>($/ton)</td>
<td>$10</td>
<td>Net revenues for use of digester projects may be negligible – esp. if manure otherwise would be used on farm and/or significant processing costs / regulations for use of digester byproducts for fertilizer replacement or bedding material. Potential benefits and revenues from land application of digestate relative to untreated manure have been suggested but subject to regulatory restrictions.</td>
</tr>
<tr>
<td>Liquid Digestate</td>
<td>($/gal)</td>
<td>To Be Determined</td>
<td></td>
</tr>
<tr>
<td>Tipping Fees (Co-Digestion only)</td>
<td>($/ton)</td>
<td>$10</td>
<td>Net revenues based on fee paid by feedstock provider and transportation cost to digester</td>
</tr>
</tbody>
</table>

*a The economic assessment evaluates the use of Biomethane for Pipeline Injection due to the similarities in their biogas upgrading requirements and the relatively limited markets for Compressed and Liquefied Biomethane.*

The revenue analysis for the economic model identifies and separately values the digester system’s environmental attributes such as Renewable Energy Credits (REC) and Greenhouse Gas (GHG or carbon) Credits. As a result, the resource value for the electricity or biomethane will be closely
related to their commodity prices (due to the ready availability of substitute power from local utility providers). Effective carbon markets and accounting methodologies have begun to develop only very recently and remain an uncertain, although potentially valuable, source of revenue for dairy digesters.

**Cost of Production**

It is very difficult to develop reliable and generally applicable “ground-up” estimates due not only to the wide range of potential technologies and design approaches for potential digester developments, but also due to the cost effects of site specific requirements and operating conditions. Therefore, a simplified total system cost approach was used based on existing cost data to develop the cost assumptions for the individual digester configurations to be analyzed in their subsequent economic assessment.

“Order of magnitude” cost estimates for digester system construction are based on research of published digester feasibility studies and discussion with industry experts to ensure their reasonableness and consistency with the corresponding productivity assumptions. Table 2-3 identifies that primary cost components that will be estimated for each digester configuration analyzed in the Economic Assessment. Given the wide variance in systems configurations and costs, no representative costs are presented below in Table 2-3. Specific cost estimates will be for each of the specific digester system configurations analyzed.

<table>
<thead>
<tr>
<th>TABLE 2-3</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Units</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Construction Cost</td>
<td>($)</td>
<td>The developer’s capital cost will be a primary driver of economic feasibility. Grant funding is also likely a key mechanism for government assistance to developers.</td>
</tr>
<tr>
<td>Grant Funding</td>
<td>($)</td>
<td></td>
</tr>
<tr>
<td>Developer Capital Cost</td>
<td>($)</td>
<td></td>
</tr>
<tr>
<td>Operating &amp; Maintenance Cost</td>
<td>($)</td>
<td>Cost may vary depending on the technology complexity and equipment operating life. Electricity costs typically assessed as parasitic energy demand requirements.</td>
</tr>
<tr>
<td>Annual Debt Cost</td>
<td>($)</td>
<td>Debt cost determined by the applicable financial parameters and developer’s equity contribution.</td>
</tr>
<tr>
<td>Taxes</td>
<td>($)</td>
<td>Tax cost based on the applicable financial parameters estimated by the model.</td>
</tr>
</tbody>
</table>

In most cases, net revenue estimates have been used to account for any additional indirect operating costs. For example, in the subsequent economic assessment for co-digestion, the tipping fees revenues for the digester operator is adjusted for any transportation and handling costs it incurs to obtain the feedstock.

The initial economic feasibility assessment will be based on the total construction cost (i.e. assuming no grant funding or production credits). However, if public capital support (i.e. government grants) for any digester configurations is determined to be readily available, the total construction cost can
be reduced in the Model to determine the developer’s capital cost. Any such reduction to the developer’s capital cost can be expected to improve the monetary return to the developer and hence the project’s economic feasibility.

Financial Parameters

Unlike the other components discussed above, the financial parameters are mostly external and independent from the project. The financial parameters represent the financial context for digester development and most of the factors are determined by general underlying economic circumstances and financial market conditions. Consequently, these factors are mostly independent and common to the various digester system configurations. Furthermore, the values of these factors are likely to be largely beyond the control of developers or public agencies. Irrespective, these market conditions may have an important role in determining the digester system’s economic feasibility.

Table 2-4 presents the key financial parameters included in the economic model. Most of the financial parameters presented below are relatively standard and straightforward in their application to the economic feasibility assessment. Inflation represents the rate and extent that costs and revenues may be expected to appreciate in nominal terms annually for the foreseeable future.

<table>
<thead>
<tr>
<th>Factor</th>
<th>Value</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inflation</td>
<td>2.5%</td>
<td>Based on the 20 year Consumer Price Index average</td>
</tr>
<tr>
<td>Debt Ratio</td>
<td>50:50</td>
<td>Higher than standard commercial loan rates</td>
</tr>
<tr>
<td>Interest Rate</td>
<td>7.5%</td>
<td>Higher than standard commercial loan rates</td>
</tr>
<tr>
<td>Debt Term (a)</td>
<td>10 - 20 years</td>
<td>Longer debt term improves feasibility</td>
</tr>
<tr>
<td>Target IRR (b)</td>
<td>Prime + 12% (c) to Prime + 15%</td>
<td>Represent the developer’s expected earnings requirement</td>
</tr>
<tr>
<td>Tax Rate</td>
<td>40.34%</td>
<td>Marginal combined federal (35%) and state (9%) corporate tax rate. Applied to the project’s taxable income (i.e. its net cash flow minus depreciation of capital and interest paid on debt)</td>
</tr>
<tr>
<td>Depreciation Period/Terms</td>
<td>5-year MACRS</td>
<td>IRS determined – accelerated depreciation will improve feasibility</td>
</tr>
</tbody>
</table>

The debt ratio expresses the likely proportion of loan funding that a developer might be expected to obtain for a digester project. Generally, bank lenders will only be willing to fund a limited portion of the cost for a new commercial project such as digester projects since it relies on comparatively untested technologies and faces relatively complex and uncertain regulatory and market conditions. Furthermore, interest rates for any borrowed money may be expected to be higher than for more standard commercial loan rates. Estimates for the economic life for digester facilities vary from
10 year up to 20 years (ECOregon, 2010; California Biomass Collaborative, 2008). A longer useful life estimate will generally improve the facility’s feasibility performance.

The Modified Accelerated Cost Recovery System\(^6\) (MACRS) is the current methodology in the U.S. tax system for recovery of capitalized costs of depreciable property investment. Under MACRS, the capitalized cost is recovered over a specified life by annual deductions for depreciation. Such “accelerated depreciation” of a capital investment will lower the near term tax liability for the project developer which will improve the economic feasibility of the project since the project debt can be more rapidly paid down. The federal tax code allows agribusinesses to utilize the 5-year MACRS depreciation schedule.

**Presentation of Findings**

The economic model has been constructed to determine the project’s estimated IRR for the project based on its projected revenues, costs and financial parameters. The IRR represents the proportion of earnings the project developer is expected to make on its equity investment over the life of the project.

Based on comparisons with other similar industry projects and discussions with industry experts it is determined that a 15 to 18% Target IRR is suitable for future digester projects. However, for more innovative and larger scale projects (e.g. such as pipeline injection), a higher Target IRR is applied recognizing the higher risk premium and difficulty in acquiring capital investment.

For each of the digester configurations, the economic model is used to estimate the project’s IRR under its specified development and operating conditions (i.e. productivity assumptions, revenue projections etc.). If the project’s IRR is greater than the Target IRR then the project will be expected to be feasible.

If the project’s IRR is less than the Target IRR, the economic model will be used to estimate the monetary subsidy necessary for the project to meet the Target IRR. The additional monetary support for the project could be achieved by increased revenues and this revenue requirement is identified as the Cost of Production (COP) value for the system’s primary product (i.e. electricity or biomethane). Additionally or alternatively, the project could meet its Target IRR requirements with the aid of additional capital funding (development grant assistance). The necessary additional capital funding (without revenue enhancement) is identified in the model as the Required Grant Subsidy (RGS).

Based on the nature and level of additional development support estimated to be required to ensure that the prototypical digester and co-digester systems are economically feasible, the nature and extent of future dairy manure digester and/or co-digester within the Central Valley over the foreseeable future will be evaluated.

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\(^6\) MACRS is an IRS approved accelerated depreciation schedule permitting qualified businesses faster recovery of their capitalized investment costs over a specified life by reducing its federal tax liability. The federal tax code allows agribusinesses to utilize the 5-year MACRS depreciation schedule.
Analysis Caveats

The economic model is based on research performed during a highly dynamic period for the digester and other renewable energy industries. There are many unknown variables facing the industry – both technological and regulatory. Consequently, quantitative analysis of the industry economics is particularly challenging and, if imbedded assumptions or factors are not recognized, any finding can be misleading or highly prone to misinterpretation.

Furthermore, most digester analyses are very site and technology-specific. In addition, most operating digester projects have been pilot or demonstration projects that have received considerable government assistance. As a result, there is extensive complexity associated with any efforts to normalize the design, costs and performance of digesters operating under very different circumstances.

Consequently, we have used a predominantly general and speculative approach since the primary purpose for this economic model and analysis is to provide a framework by which the general feasibility of digester and co-digester development can be evaluated and the role of the key economic factors determining dairy digester feasibility can be identified and assessed.

2.3 Proposed System Configurations to be Analyzed

The following four digester system configurations are suggested as illustrative representations of the key economic feasibility opportunities and constraints facing future dairy manure digesters within the Central Valley. These configurations have been selected to reflect both production/technology considerations as well as current market conditions for both dairy producers and potential biogas/biomethane consumers. These scale and constraint defined configurations have also be identified to provide a framework by which the economic and cost-effectiveness issues can be most easily identified and assessed.

- **Farm-scale biogas production for on-site electrical generation.** The revenue and cost performance for a manure-only digester operating with a 1,000-cow dairy producing electricity with air quality compliant internal combustion engines.

- **Pipeline injection scale biomethane production.** This configuration represents a large scale, high investment, technology intensive, low environmental impact scenario. The potential for such a facility (serving 10,000 cows) within close proximity to transmission will be assessed. This is the most market secure scenario for biomethane. The scale and biogas upgrade components are expected to be broadly representative of currently practiced biomethane production.

- **Co-digestion of manure with available organic feedstocks.** The biogas production gains and tipping fees for co-digestion within a complete mix digester will be evaluated for a 1,000-cow dairy importing food waste from a nearby processor. Cost impact associated with any biogas quality changes as well as nitrogen and salt loading management issues will be identified and assessed.

- **Centralized biomethane upgrade system with biogas transportation.** Most farms would not produce enough biogas to justify the cost of upgrading it to biomethane. Therefore, the financial feasibility of transporting biogas from ten 1,000-cow dairy digesters to a centralized biomethane upgrade unit will be evaluated. The potential for diseconomies of scale at a centralized facility will be considered.
The feasibility findings for these various prototypical digester and co-digester facilities will provided key information on the potential extent that future dairy digester development may be expected to occur within the Central Valley. If one or more configurations are determined to be economically feasible then it may be expected that such digester development would be expected to occur. However, if major revenue shortages, cost hurdles, development limitations or other obstacles are identified then digester or co-digester development will be dependent on public financial support and far less likely to occur in the foreseeable future.

Our initial investigations and discussions with stakeholders and industry experts suggest that distinguishing between a near term and long term perspective for assessing the economic feasibility of manure digesters is necessary. Although anaerobic digestion is not a new technology, successful commercial development of dairy biogas production still has to be proven in the United States. As discussed in the previous “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-digester Facilities” technical report, a large number of inter-related variables and factors contribute positively and negatively to manure digesters’ financial performance and their development potential as renewable resource industry.

Preliminary analysis and review of the published industry literature indicates that, at least for the near future, generally most digester systems have insufficient revenue potential to justify the full investment and operating cost for biogas production. This suggests that public financial support will remain important for fostering dairy biogas production as a future renewable resource. This is especially true for biomethane, which requires major additional costs and scales of production. The Economic Analysis Findings report to be prepared will estimate (to the extent possible based on the study’s assumptions) the magnitude of necessary public investment or other economic developments that may be necessary to provide necessary future industry support.

It is also apparent that separate feasibility tiers face future development of dairy manure digesters. Development of viable biogas production, markets, and beneficial uses could be recognized as an important initial stage for subsequent (or parallel) development of a biomethane market. The initial first tier of financial feasibility does not require any major technological improvements and can be pursued with relatively low levels of investment and on an individual farm by farm basis. Combined with viable on-site biogas uses for electricity generation, biogas production would be more likely to occur with relatively limited public support.

Such an initial “first tier” of biogas development could be an important prerequisite for development of the more capital intensive, “higher tech” and larger scale requirements for biomethane production and related use. Development of the dairy biomethane industry will involve far higher risk and greater public support for its successful future commercialization. Currently, this “second tier” of development will likely require technological improvements for the scale and cost-effectiveness improvements before adequate profitability can be achieved without continued public support.

In any case, both tiers of biogas/ biomethane development can be pursued in parallel and as complementary approaches for future successful development of dairy manure digesters within the Central Valley.
2.4 References


Report 3
Economic Feasibility Model
Findings
3.1 Methodology

As discussed in the Economic Feasibility Model Approach report, a simplified total system cost approach is used to develop the cost assumptions for the individual digester configurations analyzed in the economic assessment. The “order of magnitude” cost estimates for digester system construction used in the economic feasibility analysis are based on research of published digester feasibility studies and discussion with industry experts to ensure their reasonableness and consistency with the corresponding productivity assumptions.

The economic feasibility assessment analysis is based on the total construction cost (i.e., assuming no grant funding or production credits) with the revenue values and financial parameters assumptions identified in previous Economic Feasibility Model Approach report (ESA, 2010). The economic performance of the four generic digester facilities are estimated by the economic model and the key findings are identified and summarized. A sensitivity analysis is also performed to evaluate the comparative role that the economic factors and assumptions contribute to the model results.

3.2 System Configurations

The following four digester system configurations are used as illustrative representations of the key economic feasibility opportunities and constraints facing future dairy digesters within the Central Valley. The manure collection, digester productivity, and biogas conversion rates (detailed in the Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report) were typical of well-managed dairies collecting all of the available manure for treatment in a well-designed and operated heated, mixed digester. These configurations have been selected to reflect both production/technology considerations as well as current market conditions for both dairy producers and potential biogas/biomethane consumers. These scale and constraint defined configurations have also been identified to provide a framework by which the economic and cost-effectiveness issues can be most easily identified and assessed.

- **Farm-scale biogas production for on-site electrical generation (Manure-Only - System A).** The revenue and cost performance for a Manure-Only digester operating with a 1,000-cow dairy producing electricity with air quality compliant internal combustion engines or other “clean” electrical generation system.

- **Co-digestion of manure with available organic feedstocks (Co-digestion - System B).** The biogas production gains and tipping fees for co-digestion within a complete mix digester for a 1,000-cow dairy importing food waste from a nearby processor. Compared with the Manure-Only facility (System A), primary capital cost impacts include additional feedstock
3. Economic Feasibility Model Findings

Handling facilities, larger electrical generation system and possibly additional biogas processing equipment. Operating cost impacts higher operating and maintenance as well as possibly additional costs for feedstock acquisition and/or digestate disposal. Biogas productivity assumed to increase by 200 to 300 percent.

- **Pipeline injection scale biomethane production (Pipeline Injection – System C).** This configuration represents a large scale, high investment, technology-intensive, low environmental impact scenario. This is the most market secure scenario for biomethane. The facility would serve manure from approximately 10,000 cows. The scale and biogas upgrade components are broadly representative of currently practiced biomethane production. The facility is assumed to be in close proximity to both numerous farms supplying sufficient biogas and a suitable natural gas utility pipeline interconnection. Biogas upgrading, quality monitoring, and pipeline injection equipment is included in system cost.

- **Centralized biomethane upgrade system with biogas collection by pipeline (Centralized Biogas Collection – System D).** Similar to the biomethane upgrading facility (System C) but with distributed biogas production and transmission to the biomethane upgrading facility. Additional costs for biogas pipeline construction between numerous dairy digester facilities added to system cost.

The feasibility findings for the various prototypical digester and co-digester facilities provide key information on future dairy digester development potential within the Central Valley.

### 3.3 Findings

The financial assumptions used by the economic model are shown in Table 3-1. The same financial assumptions were applied to all four system configurations to facilitate economic performance amongst the different systems.

<table>
<thead>
<tr>
<th>TABLE 3-1</th>
<th>FINANCIAL ASSUMPTIONS FOR ECONOMIC ANALYSIS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Financial Factors</td>
<td></td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>= 2.5%</td>
</tr>
<tr>
<td>Equity to Debt Ratio</td>
<td>= 50:50</td>
</tr>
<tr>
<td>Project Life / Debt Term</td>
<td>= 15 Years</td>
</tr>
<tr>
<td>Interest Rate</td>
<td>= 7.5%</td>
</tr>
<tr>
<td>Tax Rate</td>
<td>= 40.3%</td>
</tr>
<tr>
<td>Depreciation</td>
<td>= 5 Year MACRS</td>
</tr>
<tr>
<td>Target Internal Rate of Return</td>
<td>= 18.5%</td>
</tr>
<tr>
<td>(Target IRR)</td>
<td>(Prime + 15 Percentage Points)</td>
</tr>
</tbody>
</table>


For each of the prototypical biogas systems, the above financial factors have been applied with the system performance, cost and revenue estimates to assess each system’s economic performance. The findings for each of the four digester-system configurations are presented below.

### Manure-Only - System A

The Farm-scale biogas production for on-site electrical generation represents a Manure-Only digester operating with a 1,000-cow dairy producing electricity with air quality compliant internal combustion
engines or micro-turbine generator systems (100 kW in size). This “Manure-Only” digester system represents the simplest digester system and biogas use configuration. Table 3-2 shows the system performance, cost and revenue estimates assumed for the prototypical farm sized Manure-Only digester system.

Co-digestion - System B

The Co-digestion system is largely comparable to the Manure-Only facility (System A) discussed above except that the system is modified for co-digestion of food and agricultural waste. The construction cost for System B is estimated to be approximately $200,000 higher as a result of the larger electrical generation system (200 kW in size) and additional construction of feedstock handling facilities. It is projected that the addition of 15 tons of agricultural and food waste could double the biogas production of the digester system compared to System A without altering the size of the digester.

The operating and maintenance cost for System B is expected to be greater than that applicable for the Manure-Only system to recognize the greater attention and management necessary for procuring and processing the co-digestion feedstock. A small cost has also been added to recognize the potential necessity for management of the additional liquid digestate generated by the added feedstock (approximately 1 million gallons per year). It is presumed that the liquid digestate could be used by nearby farmers or the current dairy with an increase land base (hence an added land lease cost) at a relatively small expense to the digester operator ($2,000 per year).

Table 3-3 shows the system performance, cost and revenue estimates assumed for the prototypical farm sized co-digestion system.

Pipeline Injection - System C

The high costs for biogas upgrading to biomethane (both for the necessary equipment and significant energy requirements) ensure that biomethane production requires significant economies of scale for economic feasibility. Pipeline injection of produced biomethane into the utility grid is currently the simplest and most reliable market for biomethane sales available to potential digester operators.

System C represents a “best case” location for both the necessary large-scale biogas production (10,000 cows) and very close proximity to a suitable natural gas utility pipeline interconnection. In contrast, System D represents a more common scenario of distributed and smaller scale individual biogas production. As shown in the System D analysis, pipeline delivery requirements for either the upgrade facility’s biogas input or produced biomethane will add additional production costs that will reduce the system’s economic feasibility.

The electricity requirement cost is included in the annual expenses and is based on supplying all of the system’s electrical demand with grid electricity to conservatively recognize the challenges of meeting air quality compliance standards with any use of biogas/biomethane for on-site electrical generation. Table 3-4 shows the system performance, cost and revenue estimates assumed for a
best case large scale biomethane production for pipeline injection which assumes large scale biogas production on or near the site.

### TABLE 3-2

FARM-SCALE BIOGAS PRODUCTION FOR ON-SITE ELECTRICAL GENERATION

#### MANURE-ONLY - SYSTEM A

<table>
<thead>
<tr>
<th>Capital Cost (b)</th>
<th>$1,500,000</th>
</tr>
</thead>
</table>

#### Annual Expenses

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating &amp; Maintenance</td>
<td>% of capital cost</td>
</tr>
<tr>
<td>Annual Debt Payment</td>
<td>$85,000</td>
</tr>
<tr>
<td>Total Annual Expenses (c)</td>
<td>$145,000</td>
</tr>
</tbody>
</table>

#### Annual Revenues

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas Production</td>
<td>17,200,000 cu.ft. (d)</td>
</tr>
<tr>
<td>Electricity Production</td>
<td>744,000 kWh (e)</td>
</tr>
<tr>
<td>Onsite Farm Use Offset</td>
<td>372,000 kWh (f)</td>
</tr>
<tr>
<td>Sales to Utility</td>
<td>372,000 kWh (g)</td>
</tr>
<tr>
<td>Renewable Energy Credits (REC)</td>
<td>0 kWh</td>
</tr>
<tr>
<td>Digestate (Solid)</td>
<td>3,400 tons (i)</td>
</tr>
<tr>
<td>Digestate (Liquid)</td>
<td>5,600,000 gallons (i)</td>
</tr>
<tr>
<td>Carbon Reduction (GHG Credits)</td>
<td>7,450 tonnes CO2e (j)</td>
</tr>
<tr>
<td>Total Annual Revenues</td>
<td>$127,000</td>
</tr>
</tbody>
</table>

#### Model Results

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required Annual Revenues for Adequate Profitability</td>
<td>$262,000</td>
</tr>
<tr>
<td>Annual Surplus (Shortage) Compared to Projected Total Annual Revenues</td>
<td>($135,000)</td>
</tr>
<tr>
<td>Cost of Energy ($ / kWh)</td>
<td>$0.28</td>
</tr>
<tr>
<td>Current Energy Price Shortfall ($ / kWh)</td>
<td>($0.21)</td>
</tr>
<tr>
<td>Productivity Increase Required</td>
<td>283%</td>
</tr>
</tbody>
</table>

**Notes:**

a. Generator sized assuming 15% downtime for generator maintenance.
b. Capital Cost includes design, construction, installation, permitting and utility connection costs. Electrical generation related system components estimate to be approximately $350,000.
c. "Total Annual Expenses" does not include taxes or "cost of capital" to digester investor.
d. Biogas production assumes 2.8 cu.ft. / lb VS (175 l / kg VS) biogas yield at 65% CH4.
e. Electrical production assumes 10% parasitic and flare loss.
f. Represents cost savings to dairy operations from typical "retail" utility prices.
g. Market Price Referent (MPR) for 15 year project starting in 2011 = $0.09 per kWh. Price shown is in 2010 dollars and has been adjusted for inflation.
h. Project's REC values transferred to utility under its Feed In Tariff sales.
i. Assumes 20% volatile solid destruction with 75% solids recovery with 65% moisture content.
j. Future GHG Price of $3 / tonne CO2e reduced to account for bi-annual verification costs of $11,000. All costs and revenues in the nearest thousand dollars. Totals may not add up exactly due to rounding.

**SOURCE:** ESA, 2010.
TABLE 3-3  
FARM-SCALE CO-DIGESTION FOR ON-SITE ELECTRICAL GENERATION

<table>
<thead>
<tr>
<th>CO-DIGESTION – SYSTEM B</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,000 cows dairy farm facility with air quality compliant 200 kW electrical generation system</td>
</tr>
<tr>
<td>27,375 tons of wet manure processed annually (75 tons per day)</td>
</tr>
<tr>
<td>5,475 tons of agricultural and food processing waste processed annually (15 tons per day)</td>
</tr>
<tr>
<td>4,137 tons/yr of volatile solids processed by digester (75% from manure, 25% from food waste)</td>
</tr>
<tr>
<td>Biogas / energy yield projected to double with limited system expansion required (a).</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Capital Cost (b) $1,700,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Expenses Quantity Value Total</td>
</tr>
<tr>
<td>Operating &amp; Maintenance (c) % of capital cost 8% $136,000</td>
</tr>
<tr>
<td>Annual Debt Payment $96,000</td>
</tr>
<tr>
<td>Total Annual Expenses $232,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Annual Revenues Quantity Value Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas Production 34,400,000 cu.ft.</td>
</tr>
<tr>
<td>Electricity Production 1,488,000 kWh</td>
</tr>
<tr>
<td>Onsite Farm Use Offset 372,000 kWh (d) $0.13 / kWh $48,000</td>
</tr>
<tr>
<td>Sales to Utility 1,116,000 kWh $0.074 / kWh $83,000</td>
</tr>
<tr>
<td>Renewable Energy Credits (REC) 0 kWh $0.035 / kWh $0</td>
</tr>
<tr>
<td>Digestate (Solid) 3,800 tons (e) $10 / ton $38,000</td>
</tr>
<tr>
<td>Digestate (Liquid) 6,600,000 gallons (f) (2,000)</td>
</tr>
<tr>
<td>Tipping Fees (Feedstock Purchase) 5,475 tons $10 / ton $55,000</td>
</tr>
<tr>
<td>Carbon Reduction (GHG Credits) 9,100 tonnes CO2e $2.50 / tonne CO2e $23,000</td>
</tr>
<tr>
<td>Total Annual Revenues $245,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Model Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required Annual Revenues for Adequate Profitability $365,000</td>
</tr>
<tr>
<td>Revenue Surplus (Shortage) Compared to Required Revenue ($120,000)</td>
</tr>
<tr>
<td>Cost of Energy ($ / kWh) $0.17</td>
</tr>
<tr>
<td>Current Energy Price Shortfall ($ / kWh) ($0.09)</td>
</tr>
<tr>
<td>Productivity Increase Required 128%</td>
</tr>
</tbody>
</table>

a. Biogas yield from food waste assumed to be three times higher than manure  
b. Additional construction cost for feedstock blending / storage facilities, higher electrical generation system capacity. Electrical generation related system components estimate to be approximately $500,000.  
c. Operation & maintenance cost (as % of capital cost) doubled to reflect added complexity of co-digestion  
d. On-farm electricity use assumed identical to System A  
e. Assumes 80% volatile solid destruction from the food waste fraction.  
f. Additional expense for transfer or land lease to manage net increased liquid digestate (1,000,000 gallons).  
All costs and revenues in the nearest thousand dollars. Totals may not add up exactly due to rounding.  

TABLE 3-4
LARGE-SCALE BIOMETHANE PRODUCTION FOR PIPELINE INJECTION

PIPELINE INJECTION – SYSTEM C

10,000 cows dairy farm manure digester facility with pipeline quality upgrading and injection.
Industrial sized on-site biomethane production injecting into nearby Natural Gas transmission system
273,750 tons of wet manure processed annually (750 tons per day)
31,030 tons of volatile solids in manure processed by digester annually (11% VS in manure)

Capital Cost
Digester System (a) $5,750,000
Biogas Upgrading, Testing, and Injection Systems (b) $3,250,000
Connection to Utility Natural Gas Pipeline $700,000
Total Construction Cost $9,700,000

Annual Expenses
Operating & Maintenance (c) $612,000
Electricity Required for Upgrading (d) $143,000
Annual Debt Payment $578,000
Total Annual Expenses $1,333,000

Annual Revenues
Biomethane Production (e) $394,000
Renewable Energy Credits (REC) $432,000
Digestate (Solid) $340,000
(Liquid) $0
Carbon Reduction (GHG Credits) $224,000
Total Annual Revenues $1,390,000

Model Results
Required Annual Revenues for Adequate Profitability $2,059,000
Revenue Surplus (Shortfall) Compared to Required Revenue ($720,000)
Cost of Energy ($ / 1,000 cu.ft.) $10.79
Current Energy Price Shortfall ($ / 1,000 cu. ft.) ($6.62)
Productivity Increase Required 159%

a. Digester system cost based on System A costs (without electrical generation), adjusted for economies of scale.
b. Typical PSA system at this scale costs $2-3 million, installed. Additional cost for pipeline injection and emission controls.
c. System operating and maintenance costs rate projected to be 50% higher than System A.
d. PSA biogas upgrade system rated to use 6-8 kW of electricity per 1,000 cu.ft. of biogas treated.
e. Biomethane production assumes 5% parasitic use for heat, and 95% methane capture efficiency.
f. REC credits based on 980 BTU / cu.ft. biomethane heat content and 45% power plant electrical conversion efficiency.
All costs and revenues in the nearest thousand dollars. Totals may not add up exactly due to rounding.


Centralized Biogas Collection and Upgrade - System D

System D represents a more commonly possible configuration of the biogas production necessary
to support a large scale biogas upgrade facility than the major onsite digester facilities assumed
for System C. Under System D, numerous farm scale digester systems (similar to the System A
digester facility) would transmit their biogas by pipeline to the centralized biogas upgrade facility
that would performance similar to the System C upgrade facility.
However, in addition to the additional cost for biogas collection and delivery, the numerous individual farm scale digesters would not achieve any major economies of scale and consequently would have a considerably higher cost of production for their biogas although they would achieve some savings over System A since they would not require any onsite electrical generation facilities.

Table 3-5 shows the system performance, cost and revenue estimates assumed for the large scale centralized biogas upgrade facility for pipeline injection primarily supplied by off-site farm scale dairy digesters with pipeline delivery.

### TABLE 3-5

**CENTRALIZED BIOMETHANE UPGRADE FACILITY WITH PIPELINE COLLECTION OF BIOGAS**

<table>
<thead>
<tr>
<th>CENTRALIZED BIOGAS COLLECTION AND UPGRADE – SYSTEM D</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-site digester (2,000 cow capacity) with large-scale centralized biomethane upgrading facility (like System C)</td>
</tr>
<tr>
<td>Biogas transferred by pipeline from 8 additional off-site farm-sized digesters (like System A).</td>
</tr>
<tr>
<td>Biomethane injected into nearby Natural Gas transmission system.</td>
</tr>
<tr>
<td>Biomethane and energy production projected to match System C performance.</td>
</tr>
</tbody>
</table>

#### **Capital Cost**

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Digester System (a)</td>
<td>$11,200,000</td>
</tr>
<tr>
<td>Biogas Upgrading and Testing Systems</td>
<td>$3,250,000</td>
</tr>
<tr>
<td>Utility Connection</td>
<td>$700,000</td>
</tr>
<tr>
<td>Pipeline Connection (b)</td>
<td>$1,050,000</td>
</tr>
<tr>
<td><strong>Total Construction Cost</strong></td>
<td><strong>$16,200,000</strong></td>
</tr>
</tbody>
</table>

#### **Annual Expenses**

<table>
<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Value</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating &amp; Maintenance</td>
<td>% of capital cost</td>
<td>6%</td>
<td>$612,000</td>
</tr>
<tr>
<td>Electricity Required for Upgrading</td>
<td>1,100,100 kWh</td>
<td>$0.13 / kWh</td>
<td>$143,000</td>
</tr>
<tr>
<td><strong>Annual Debt Payment</strong></td>
<td></td>
<td></td>
<td>$946,000</td>
</tr>
<tr>
<td><strong>Total Annual Expenses</strong></td>
<td></td>
<td></td>
<td>$1,701,000</td>
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#### **Annual Revenues**

<table>
<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Value</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas Production</td>
<td>94,400,000 cu.ft.</td>
<td>$4.17 / 1,000 cu.ft.</td>
<td>$394,000</td>
</tr>
<tr>
<td>Renewable Energy Credits (REC)</td>
<td>12,335,000 kWh</td>
<td>$0.035 / kWh</td>
<td>$432,000</td>
</tr>
<tr>
<td>Digestate (Solid)</td>
<td>34,000 tons (d)</td>
<td>$10 / ton</td>
<td>$340,000</td>
</tr>
<tr>
<td>(Liquid)</td>
<td>56,000,000 gallons (d)</td>
<td>$0 / gallon</td>
<td>$0</td>
</tr>
<tr>
<td>Carbon Reduction (GHG Credits)</td>
<td>74,500 tonnes CO2e</td>
<td>$3 / tonne CO2e</td>
<td>$224,000</td>
</tr>
<tr>
<td><strong>Total Annual Revenues</strong></td>
<td></td>
<td></td>
<td>$1,390,000</td>
</tr>
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</table>

#### **Model Results**

<table>
<thead>
<tr>
<th>Item</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required Annual Revenues for Adequate Profitability</td>
<td>$2,933,000</td>
</tr>
<tr>
<td>Annual Surplus (Shortage) Compared to Projected Total Annual Revenues</td>
<td>($1,543,000)</td>
</tr>
<tr>
<td>Cost of Energy ($ / 1,000 cu.ft.)</td>
<td>$20.52</td>
</tr>
<tr>
<td>Current Energy Price Shortfall ($ / kWh)</td>
<td>($16.35)</td>
</tr>
<tr>
<td>Productivity Increase Required</td>
<td>392%</td>
</tr>
</tbody>
</table>

---

a. Digester capital cost assumes construction cost of 8 one-thousand cow systems plus 1 two-thousand cow system. Cost adjusted slightly for economies of scale.
b. Pipeline cost assumes 8 dairies require 6 miles of pipeline at $175,000 / mile.

All costs and revenues in the nearest thousand dollars. Totals may not add up exactly due to rounding.

SOURCE: ESA, 2010
System Comparisons

Table 3-6 provides a summary comparison of the findings from the initial economic modeling for the four digester-system configurations. The table shows both the key characteristics, cost and performance estimates for the individual systems.

Sensitivity Analysis

Figure 3-1 presents the results of a sensitivity analysis performed on each of the four system configurations. The sensitivity analysis provides a measure of the extent that the system’s economic performance is directly dependant on each economic assumption independently. A high sensitivity indicates that small changes in the value of the indicated economic factor result in large changes in the project’s financial performance (i.e., net present worth).

Consequently, factors with high sensitivity are more influential in determining the digester system’s economic performance and therefore need to be valued more accurately to reduce risk and ensure success. The most highly sensitive values are also those which engineers and project designers should focus on when trying to improve the financial feasibility of the project.
### TABLE 3-6
COMPARISON OF DIGESTER SYSTEMS ECONOMIC FEASIBILITY

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Size</td>
<td>1,000 Cows</td>
<td>1,000 Cows</td>
<td>10,000 Cows</td>
<td>10,000 Cows</td>
</tr>
<tr>
<td></td>
<td>Facility</td>
<td>100 kW Generator</td>
<td>200 kW Generator</td>
<td>Near site Biogas Production. Biogas Upgrade and Pipeline Injection</td>
<td>Off site Biogas Produced by Farm sized digesters. Pipeline to Centralized Upgrade Facility and Pipeline Injection</td>
</tr>
<tr>
<td></td>
<td>Energy Production</td>
<td>744 MWh</td>
<td>1,488 MWh</td>
<td>94.4 million cu. ft.</td>
<td>94.4 million cu. ft.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>(12,600 MWh)</td>
<td>(12,600 MWh)</td>
</tr>
<tr>
<td>Economic Performance</td>
<td>Cost</td>
<td>$1.5 m</td>
<td>$1.7 m</td>
<td>$9.7 m</td>
<td>$16.2 m</td>
</tr>
<tr>
<td></td>
<td>Digester</td>
<td>$1.15 m</td>
<td>$1.2 m</td>
<td>$5.7 m</td>
<td>$11.2 m</td>
</tr>
<tr>
<td></td>
<td>Energy Conversion</td>
<td>$350 k</td>
<td>$500 k</td>
<td>$4 m</td>
<td>$5 m</td>
</tr>
<tr>
<td></td>
<td>O&amp;M</td>
<td>4%</td>
<td>8%</td>
<td>6%</td>
<td>6%</td>
</tr>
<tr>
<td></td>
<td>Annual Expenses</td>
<td>$145 k</td>
<td>$232 k</td>
<td>$1.33 m</td>
<td>$1.7 m</td>
</tr>
<tr>
<td></td>
<td>Annual Revenues</td>
<td>$127 k</td>
<td>$245 k</td>
<td>$1.4 m</td>
<td>$1.4 m</td>
</tr>
<tr>
<td></td>
<td>Energy Sales</td>
<td>$76 k</td>
<td>$131 k</td>
<td>$826 k</td>
<td>$826 k</td>
</tr>
<tr>
<td>Model Findings</td>
<td>Required Annual Revenues</td>
<td>$262 k</td>
<td>$365 k</td>
<td>$2.06 m</td>
<td>$2.93 m</td>
</tr>
<tr>
<td></td>
<td>Revenue Surplus (Shortage) vs. Required Revenue</td>
<td>($135 k)</td>
<td>($120 k)</td>
<td>($670 k)</td>
<td>($1.54 m)</td>
</tr>
<tr>
<td></td>
<td>Revenue Increase Required</td>
<td>106%</td>
<td>49%</td>
<td>48%</td>
<td>110%</td>
</tr>
<tr>
<td></td>
<td>Cost of Energy</td>
<td>$0.28 / kWh</td>
<td>$0.17 / kWh</td>
<td>$10.79 / 1,000 cu. ft.</td>
<td>$20.52 / 1,000 cu. ft.</td>
</tr>
<tr>
<td></td>
<td>Current Energy Price Shortfall</td>
<td>$0.21 / kWh</td>
<td>$0.09 / kWh</td>
<td>$6.62 / 1,000 cu. ft.</td>
<td>$16.35 / 1,000 cu. ft.</td>
</tr>
<tr>
<td></td>
<td>Productivity increase required</td>
<td>283%</td>
<td>128%</td>
<td>159%</td>
<td>392%</td>
</tr>
</tbody>
</table>

**SOURCE:** ESA, 2010.
None of the digester systems are economically viable (i.e., meet the minimal acceptable internal rate of return on investment) for their developer under the current assumed values. The sensitivity analysis also shows that no single economic factor, even when changed by 50%, would ensure the economical viability of any of the digester systems analyzed.

However, as shown in Figure 3-1, certain economic factors had a greater sensitivity than others. In order for these projects to become economically viable, it is likely that substantial improvements will have to be gained in several areas. Every system’s financial performance was most sensitive to capital cost and revenues. As a result, increasing revenues while reducing capital costs will be the most impactful way to improve financial performance. For the co-digestion and large-scale biomethane systems (B and C, respectively), reducing expenses will also be an important factor for improving the economic viability of these digester systems. However, since their financial performance is less sensitive to expenses than revenues, it will generally pay to invest more capital if greater energy production can be achieved.

It is believed that future development costs could decrease with large-scale deployment of the digester and energy conversion technologies. Digester construction costs could be reduced by standardizing construction methods and utilizing improved materials. However, due to their large size and potential safety issues (as well future increases in compliance requirements), reductions in digester construction costs may not be sufficient to significantly improve the economics.

However, energy conversion equipment costs could decline significantly as new technologies are developed to reduce emissions and improve conversion efficiency. More efficient energy conversion systems would also generate greater revenues. This study assumed a small electricity generator with a conversion efficiency of 25 percent. Future fuel cells may be able achieve 40-50 percent efficiency, which would double energy-related revenues.

In addition, the model assumed a relatively low biogas yield from manure. Improvements in manure and digester management could improve the biogas gas and energy yield by 50-100 percent. Nonetheless, the economic model shows that energy revenues accounted for about half of the total revenues projected for these digester systems. Increased non-energy revenues from digestate products as well as incentive programs such as carbon trading markets, higher feed-in tariffs and REC credits will also likely be needed to ensure future financial feasibility of digester systems in the Central Valley. Carbon markets along with cap-and-trade policies could dramatically increase these non-energy revenues for anaerobic digesters.

With the recent proposal of cap-and-trade legislation under California’s Global Warming Solutions Act to take effect by the beginning of 2012, the value of carbon reduction credits is likely to increase. Some estimates have predicted prices for carbon of up to $15 per tonne of CO2 equivalent (although the net value of the credits will have to be reduced to account for the fixed annual compliance and certification costs). As an example of the effect of carbon credits on financial viability, if the net carbon reduction credit revenues were increased by five times (equivalent to a net value of 11.25 $/tonne CO2e) the revenues for the four scenarios would increase by 54%, 38%, 64%, and 64%, respectively. This would provide enough additional revenue to make the large-scale Pipeline Injection Project (System C) financially feasible, and it would provide half to three-quarters of the needed...
revenue for the remaining projects. However, carbon prices will be volatile and difficult to predict, especially in light of the lack of relevant historical data. Thus, currently, additional revenues streams may be required.

For the energy revenues, a combination of increased biogas yield, conversion efficiency, and feed-in tariffs would increase the energy revenues additively (although on-farm electricity offset values would not be expected to be affected by the feed-in tariff). For example, 20% increases in digester and generator performance along with a 10% increase in mean energy value would increase energy revenues by 50%. If the non-energy revenues (i.e., digestate value and carbon credits) increased by 50% as well, the total revenue stream would also increase by 50%. From the required annual revenues and revenue shortfall calculations, the total revenue streams would need to be increased by 30-50% without considering reductions in construction and operating costs in order to achieve the target IRR.

The regulatory framework for providing non-energy revenues is currently being reviewed in rate setting rulemaking at the California Public Utilities Commission (CPUC). CPUC is instituting rulemaking to continue implementation and administration of the California Renewables Portfolio Standard Program (Rulemaking 08-08-009). Three dairy-digester TAG participants (Sustainable Conservation, Agricultural Energy Consumers Association [AECA] and Inland Empire Utilities Agency [IEUA]) have filed briefings on that matter with the CPUC to obtain better prices for electricity generated from biogas. Their briefs indicate that the CPUC should follow the directions in Senate Bill (SB) 32 to expand the existing Feed-In Tariff Program so that customers can install small, renewable, distributed generating facilities (i.e., farm scale biogas digesters), interconnect those facilities quickly to the electrical grid, and be paid a price that includes factors dictated in SB 32 to internalize the environmental benefits of renewable energies. For example, the brief states the following:

"The primary obstacle to effective commercialization of biogas energy projects in California is the lack of a price signal which recognizes the full array of renewable and environmental benefits provided by the technology. Implementation of SB 32 provides the Commission an important opportunity to address both the high environmental compliance costs and the unique benefits in setting a rate for energy generated by renewable biogas projects."

AECA and IEUA have proposed that the CPUC reserve 150 MW of the total 750 MW program to incubate biogas generation projects at California dairy, food processing and wastewater treatment facilities. They state this would be fully consistent with legislative intent and already established state strategic energy goals and policies.

### 3.4 Conclusions

The economic model was developed to provide a framework to facilitate simple comparisons and understanding of the key economic inter-relationships between system costs, performance and revenue potential. Most of the past economic feasibility studies on dairy digesters provide detailed
financial analyses of specific proposed digester systems generally supplemented with extensive preliminary design and engineering.¹

However, this feasibility analysis instead aims to provide a more general and “high level” overview of the relative opportunities and hurdles facing future and greater development of dairy digester systems within the Central Valley. As such the analysis does not intend to be representative of any specific dairy digester technologies. Instead, the analysis aims to demonstrate of the key factors that determine the potential economic viability of dairy digester systems in the Central Valley.

The analysis’s more general and generic approach nonetheless clearly shows the underlying fundamental revenue challenges facing future dairy digesters and provides preliminary evidence and some “order of magnitude” indications of the factors that need to be addressed for future greater economically successful dairy digester development to occur more widely within the Central Valley. The model’s findings on the cost-of-energy, productivity and revenue shortages of dairy digesters can provide a useful indication of the supplemental funding that that would be necessary to ensure that system would be economically viable. Because the systems’ total revenue requirements are presented, the current findings can be used to compare these scenarios with alternate values for digester productivity and revenues.

The principal conclusions are summarized below:

**The costs of energy produced from digester biogas are substantially higher than current “retail” prices for electricity and natural gas.** Currently the potential revenue sources from the positive environmental attributes of manure-derived biogas are insufficient to offset the higher production costs for digester development and operation. Conventional energy prices are critical underlying revenue constraints for dairy digesters. Currently most potential customers are unlikely to purchase biogas or biomethane at prices much above the conventional produced market price.

**Current Feed-In Tariff (FIT) prices are too low to support electrical generation with biogas.** Under the current Market Price Referent (MPR) rate setting process, renewable energy projects such as dairy digesters are offered an average purchase price far below “retail” utility prices. Furthermore, dairy digesters are unable to manage their electrical production to take full advantage of “time of delivery” price factors that offer higher peak time prices for supplied electricity. In addition, under current regulation, dairy digesters also forego any Renewable Energy Credits (REC) revenues as these are bundled under the FIT program.

¹ Review of the existing research literature on digester systems reveals a very wide variety in the design, technology, costs and performance of the systems that have been proposed and/or construction to date. As a result, it is difficult to derive precise system cost and performance estimates and consequently the cost, price and performance assumptions used for the Economic Model are intended to provide reasonable “ball-park” estimates to facilitate analysis of these factors’ inter-relationships and the other environmental issues facing future dairy digester development within the Central Valley.
Uncertainty in the future revenue potential for carbon or renewable energy credits to support dairy digester development. Although the environmental benefits of anaerobic digestion over current manure treatment practices has been well documented, economic mechanisms for incorporating the value of environmental stewardship into the balance sheets of anaerobic digesters have yet to fully evolve. The development of carbon markets or governmental agency mandated support for renewable energy and alternative manure management practices are likely necessary to ensure economic viability of manure digesters.

High development costs for dairy digester in the Central Valley decrease the economic feasibility of dairy digesters. Construction and permitting costs in California are generally higher than other agricultural regions. As a result, dairy digesters are more expensive to build. In addition, since most Central Valley dairies are located in ozone non-attainment areas, air quality emission controls required for electrical generators (i.e., to comply with NOx standards) add additional development costs. Water quality requirements on digester and dairy operations may also add to facility development costs. In the absence of any offsetting governmental grant funding or other government support, the capital costs for dairy digesters is higher than the capital costs for similar dairy digester systems built outside of California.

Capital availability. Private funding for digester developments in California is scarce and costly - particularly while the technology and regulatory environment is uncertain and relatively complex. It is also unclear when the loan markets for such projects will improve sufficiently to offer debt financing. The System A through D scenarios assumed that 50 percent debt financing would be possible at a 7.5 percent rate of interest. However, if such debt financing remains unavailable, the economic feasibility of the digester systems will be further weakened.

Investor return on investment requirements. While greater “commercialization” could reduce future development costs, in the meantime private investors generally will require comparatively high returns on their equity investment for digester projects. The Target Rate of Return for their investment is 18.5 percent which reflects a substantial return premium that acknowledges the comparative risk of the venture. Some investors may require even higher returns, depending on their relative risk tolerance. As a result, this adds considerable additional economic burden to the digester projects compared with more standard business ventures.

Co-digestion offers substantial improvements in economic viability. Comparison between the Manure-Only (System A) and Co-digestion (System B) suggest that potential major gains in biogas productivity may be obtainable at a relatively minor additional cost. However, the economic analysis presumes that adequate feedstock can be obtained and that the digester operator will still “net out” tipping fee revenues from the producers of the food and agricultural waste that would be used as the co-digester feedstock. In addition, the economic model also assumes that the excess liquid digestate can be disposed of relatively easily and at a
minor annual cost ($2,000 per year). Loss of the tipping fee revenues and/or higher digestate disposal costs would reduce the economic feasibility of the co-digestion.

**Co-digestion is likely to be important for economically feasible biomethane production.** The model results identify the substantial costs for the utility pipeline injection systems and for biogas pipeline delivery. Because of the limited biogas productivity of Manure-Only digesters, co-digestion (due to the increased gas production) will likely be important for any successful future biomethane production projects. Furthermore, at the larger scale, digester projects may be more likely to have access to co-digestion feedstocks. Although co-digestion was not included in the financial analysis for biomethane producing digesters, the Manure-Only Biomethane System C had the lowest revenue increase requirement, and thus may become financially viable with co-digestion.

**Technological advances alone may improve economic feasibility but appear unlikely to ensure the viability of dairy digesters.** Given the scale of the current revenue gap facing the dairy digester systems, even relatively substantial improvements in technology (either in productivity or cost reductions) will also require additional improvements in other economic factors or public funding support for greater dairy digester development to occur within the Central Valley.

**A combination of technical and economic improvements will be necessary.** Although dairy digesters may not be financially feasible today, a combination of technological improvements and regulatory conditions that simultaneously reduce costs (both initial and ongoing) and increase revenues could drive dairy digesters toward financial stability. For example, the Manure Only (System A) digester would generate a 15% IRR if the life of the system were extended by 5 years, the capital and operating costs were reduced by 25%, and the revenue was increased by 25%.

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However, there are concerns that co-digestion could potentially add impurities (i.e. siloxanes) to the biogas that might in turn required in additional and substantially higher biomethane upgrading costs.
Appendix A
Compilation of Comments Received for the Economic Reports
## APPENDIX A
Compilation of Comments Received for the Economic Reports

### Comments on April 2010 Version 1 of Key Factors Report

<table>
<thead>
<tr>
<th>Commentator</th>
<th>Date</th>
<th>Page</th>
</tr>
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<tbody>
<tr>
<td>John Fiscalini (Fiscalini Farms)</td>
<td>April 9, 2010</td>
<td>A-1</td>
</tr>
<tr>
<td>Ross Buckenham (Calbioenergy)</td>
<td>April 23, 2010</td>
<td>A-3</td>
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<tr>
<td>John Menke (SWRCB)</td>
<td>April 26, 2010</td>
<td>A-8</td>
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<tr>
<td>Ramon Norman (SJVAPCD)</td>
<td>April 28, 2010</td>
<td>A-14</td>
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<tr>
<td>Andy Freeman (Ingersoll Rand)</td>
<td>April 28, 2010</td>
<td>A-15</td>
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<tr>
<td>Cheryl Lee (CPUC)</td>
<td>April 30, 2010</td>
<td>A-70</td>
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<tr>
<td>Ken Brennan (PG&amp;E)</td>
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<td>A-120</td>
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<tr>
<td>Jackson Lehr (Calbioenergy)</td>
<td>April 30, 2010</td>
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<td>Jackson Lehr (Calbioenergy)</td>
<td>May 3, 2010</td>
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<tr>
<td>Eugene Cadenasso (CPUC)</td>
<td>May 3, 2010</td>
<td>A-184</td>
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<tr>
<td>Jeffrey G. Reed (SDG&amp;E and SoCalGas)</td>
<td>May 5, 2010</td>
<td>A-188</td>
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</table>

### Comments on May 2010 Version 2 of the Key Factors Report

<table>
<thead>
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<th>Commentator</th>
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<tbody>
<tr>
<td>Larry T. Buckle (Organic Energy Corp.)</td>
<td>May 17, 2010</td>
<td>A-239</td>
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<tr>
<td>Allen Dusault (Sustainable Conservation)</td>
<td>May 17, 2010</td>
<td>A-249</td>
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<tr>
<td>Dave Warner (SJVAPCD)</td>
<td>May 17, 2010</td>
<td>A-252</td>
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<tr>
<td>Kevin Maas (Farm Power)</td>
<td>May 23, 2010</td>
<td>A-258</td>
</tr>
<tr>
<td>Daniel Mann (MT-Energie)</td>
<td>May 24, 2010</td>
<td>A-260</td>
</tr>
<tr>
<td>Neil Black (Calbioenergy)</td>
<td>May 24, 2010</td>
<td>A-264</td>
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<tr>
<td>Martha Davis (Inland Empire Utility Agency)</td>
<td>May 24, 2010</td>
<td>A-267</td>
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<tr>
<td>Jeff Cox (Fuel Cell Energy)</td>
<td>May 24, 2010</td>
<td>A-269</td>
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<tr>
<td>Michael Boccadora (Agricultural Energy Consumers Association)</td>
<td>May 24, 2010</td>
<td>A-274</td>
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<tr>
<td>Daniel Mann (MT-Energie)</td>
<td>May 24, 2010</td>
<td>A-277</td>
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<tr>
<td>Ken Brennan (PG&amp;E)</td>
<td>May 25, 2010</td>
<td>A-280</td>
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### Comments on August 2010 Economic Feasibility Model Report

<table>
<thead>
<tr>
<th>Commentator</th>
<th>Date</th>
<th>Page</th>
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<tbody>
<tr>
<td>Daryl Maas (Pixley Biogas)</td>
<td>August 12, 2010</td>
<td>A-285</td>
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<tr>
<td>Allen Dusault (Sustainable Conservation)</td>
<td>August 12, 2010</td>
<td>A-288</td>
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<tr>
<td>Dave Warner (SJVAPCD)</td>
<td>August 17, 2010</td>
<td>A-291</td>
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### Comments on October 2010 Economic Feasibility Model Findings Report

<table>
<thead>
<tr>
<th>Commentator</th>
<th>Date</th>
<th>Page</th>
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<tbody>
<tr>
<td>Ken Brennan (PG&amp;E)</td>
<td>October 27, 2010</td>
<td>A-294</td>
</tr>
<tr>
<td>Daryl Maas (Pixley Biogas)</td>
<td>October 27, 2010</td>
<td>A-296</td>
</tr>
<tr>
<td>Dan Geis (Agricultural Energy Consumers Association)</td>
<td>November 11, 2010</td>
<td>A-298</td>
</tr>
<tr>
<td>Tracy Goss (South Coast Air Quality Management District)</td>
<td>November 12, 2010</td>
<td>A-301</td>
</tr>
</tbody>
</table>
Ms. Jennifer Tencati,

I am writing to express my support of allowing dairy farms with digesters to bring in offsite substrates to add to material produced on farms for anaerobic digestion. As an owner of a digester, and I believe I have the last digester to be installed in California on a dairy farm, I am most aware of the tremendous costs associated with the installation of a state-of-the-art digester system. Under the current rules, the digester on my dairy farm will very likely never pay for itself. The cost of the initial design and installation of the system, monthly and annual maintenance, and compliance costs consume all of the income generated by the sale of the electricity produced from the CHP unit (combined heat and power). I have a twenty year lease from my financing institution for the initial installation costs, and I am told that the engine’s life expectancy is less than ten years, so before half of the load is paid I will expect to buy a new engine at a cost of $600,000 to $1,000,000, which will also need to be financed. This is the true economic situation with my current system. Almost 40% of the project was paid for with three different grants, and without the grant money, there would be no point to even thinking of such an investment.

Given the overall environmental benefit the digester provides: renewable power, improved air quality, improved water quality, marketable solid material for soil building, and heat for sanitation or other uses, allowing the use of currently landfill-bound biomass materials, to be diverted through anaerobic digesters to produce renewable energy makes more sense. By allowing this offsite "waste" to be digested, it also addresses the growing problem of rapidly filling landfills. The economic feasibility is great; one can charge a "tipping fee" for the offsite products, additional energy is produced which equals additional revenue in power sales and heat recovery, and the biological solids from the digester can be sold as soil amendments. There are many different substrates that can be used in digesters, many of which are currently disposed of by either dumping on agricultural land and then disking into the soil, or by sending to landfills.

I understand that the concern about allowing the offsite co-digestate onto a dairy is the possibility that these additional materials may end up on farm ground as excessive nutrients. What we do not have at this time is good scientific evidence of what happens to materials as they are processed through an anaerobic digester. There are processes available to reduce the nutrient load if it is indeed necessary. I strongly urge the Water Board to allow co-digesting and perform testing on the incoming products as well as the digester effluent to determine the total effect on the land where the end products are applied.

As a matter of interest, we at Fiscalini Farms have been awarded a research grant through the USDOE (United States Department of Energy) to test for water quality, air quality, and economic feasibility. We are currently watching for additional research grants to further our knowledge of digestion inputs and outputs, and also for grants to fund the installation of a water treatment post digester system.

John Fiscalini
Fiscalini Farms
Fiscalini Cheese Company
7231 Covert Road
Modesto CA 95358
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KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES - COMMENTS

1) Please emphasize that the EIR should also be focused on facilitating “manure only” digester development – not just co-digestion. There was a comment that developers are not interested in manure only digester projects. This is not true, the early adopters will for sure be manure only digesters and they need to be helped by this EIR.

2) There is currently NO net metering available to a dairy producing electricity from biogas. The NEMBIO net metering terminated 12-31-2009 and no new connections will be considered. The ONLY opportunity to sell dairy biogas electricity is currently pursuant to a Feed in Tariff which for PG&E is done using the E-SRG PPA where they pay the MPR price based on fossil fuel natural gas with no value being assigned to renewable electricity.

3) AB920 is purely a Solar net metering provision and does not apply to any digester electricity.

4) A major problem dairy biogas electricity generation that needs to sell to a utility using the FIT (discussed in 2 above) this requires an interconnect using a FERC process that although they require a fast track process for small renewable generators these projects are...
being treated by utilities as a “non-fast track” projects and these interconnects are taking up to a year or more (rather than a few months) to obtain and the costs are huge. The whole interconnect process needs to be streamlined.

5) Attached is a Kern County letter that shows a good practice at the County level that should be made part of the EIR for “manure only” digesters in other counties to acknowledge up front that dairies have a by-right to develop up to a 10MW electric biogas fueled generation project.

Comments on the Economic Feasibility paper will be handled on the upcoming phone call requested by the CPUC. Please invite me to that call.

From: Jennifer Tencati [mailto:j.tencati@circlepoint.com]
Sent: Thursday, April 22, 2010 8:34 PM
To: Jennifer Tencati
Cc: 'Paul Miller'; 'Stephen Klein'
Subject: 2nd Presentation for April 23rd Dairy Digester TAG Meeting

Hello TAG members,

Attached, please find a PDF of a CalRecycle presentation that will be given at tomorrow’s TAG meeting.

If you have any questions, please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x131.

Kind regards,
Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131
November 10, 2009

Mr. John Schaap, P.E.
Provost & Pritchard Consulting Group
130 N. Garden Street
Visalia, CA 93291

Re: Determination of Similar Use Request – Biogas Recovery and Electricity Production

Dear Mr. Schaap,

This Office has completed its review of your request to determine that biogas recovery operations and related electricity production should be deemed to be a permitted accessory use in the County's A (Exclusive Agricultural) District. The applicable provisions in the Kern County Zoning Ordinance to consider this request relates to a "Determination of Similar Use" performed by this Department as set forth in Section 19.08.030 et seq. of that ordinance. After our review of the purpose and intent of the County's "A" District, the range of uses permitted therein, and the available information pertaining to biogas recovery systems, this Department has determined that electrical power plants powered by methane produced from an on-site biogas recovery system should be classified as a permitted use in that Zoning District, provided that the electrical power plant and biogas recovery system is accessory to an on-site confined animal facility.

Specifically, the following language will be recommended to be added to Section 19.12.020.E of the Kern County Zoning Ordinance the next time text amendments will be considered by the Kern County Planning Commission and the Kern County Board of Supervisors:

Electrical power generating plant (or cogeneration plant when heat recovery is provided) in conjunction with a biogas recovery system associated with a confined animal facility, subject to the following criteria:

1) The rated capacity of the power plant shall not exceed ten (10) Megawatts.

2) There are no off-site dwellings located within 500 feet of the proposed plant site.

Appendix A-6
3) The power plant is predominately powered by methane gas produced through a biogas recovery system using an anaerobic digester system (e.g., covered lagoon, complete mix digester, plug flow digester or sequencing batch reactor).

4) The generating plant will be constructed on, or immediately contiguous to, a confined animal facility and the biogas used to power the power plant will be produced exclusively from the recovery of biogas from that confined animal facility.

5) All pre-digested animal waste is stored in covered lagoons or other completely enclosed structures.

6) The internal combustion engine(s) powering the generator are gas-driven.

7) Hydrogen sulfide produced from the biogas recovery process is either treated or burned efficiently enough so as to not be a detectable source of nuisance odor, as determined by the applicable Air Pollution Control District.

This determination shall become effective on November 17, 2009, unless, prior to that date, an appeal to this determination is filed with this Department, along with the required $420 appeal fee, in which case this determination will be scheduled for consideration by the Kern County Board of Supervisors, as provided for in Section 19.08.060 and 19.08.070 of the Zoning Ordinance. On the effective date of this determination, this Department may authorize this use of property in the A District as provided herein until such time as the Board of Supervisors formally considers and takes action on a formal amendment to the text of the Kern County Zoning Ordinance.

Should you have any questions, please contact me at (661) 862-8620.

Sincerely,

Jim Ellis, AICP
Operations Division Chief

[Signature]

CC: Ted James, Interim Director, RMA
    Matt Constantine, Director of Public Health
    Agricultural Commissioner
    Chuck Lackey, Director, ESS
    Lorelei Oviatt, Division Chief
    Kathe Malouf, Supervising Planner
    Matt Hall and Shawn Beyeler
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Paul Miller

From: Jennifer Tencati [j.tencati@circlepoint.com]  
Sent: Tue 5/4/2010 11:38 AM  
To: Paul Miller  
Cc:  
Subject: FW: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report  
Attachments: Comments on Economic Study Report.jlm.doc (65KB)

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From: John Menke [mailto:jmenke@waterboards.ca.gov]  
Sent: Monday, April 26, 2010 4:45 PM  
To: Jennifer Tencati  
Cc: 'Paul Miller'; Clay Rodgers; Syed Ali; Stephen Klein  
Subject: Re: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Given the limited time available between announcement of the conference call and the time of the call this morning, I was unable to review the report and prepare comments in time for the call. Attached are my written comments; please distribute them as appropriate. Also, I assume that notes were made during the conference call and will be distributed. Please ensure that I receive a copy of those notes.

I am curious to know if RWB staff are reviewing the draft reports before the reports are sent to all TAG members. It appears to me that the documents would benefit from a RWB staff review before they are sent out.

John Menke  
State Water Resources Control Board  
Division of Water Quality  
P.O. Box 100  
Sacramento CA 95812-0100  
Voice: (916) 341-5587  
Fax: 341-5463  
jmenke@waterboards.ca.gov

>>> Jennifer Tencati <j.tencati@circlepoint.com> 4/23/2010 4:03 PM >>>

Dear TAG members,

In follow up to our third TAG meeting today, we have arranged for a call in number for the 10:30 a.m. call on Monday, April 26th to discuss the Administrative Draft Economic Feasibility report (attached).

https://exchange.csassoc.com/exchange/PMiller/Inbox/FW:%20Dairy%20Digester%20Mo...  7/24/2010

Appendix A-8
The call in number is: (605) 475-4900
ID number: 501775#

You may also join the meeting in person. It will be held at CPUC's San Francisco office at 505 Van Ness Avenue in the Golden Gate Room. You may enter the building on Golden Gate Avenue, next to the ATM machine and go directly to the Golden Gate Room.

Parking is available on the street (metered) or at a lot on Golden Gate and Franklin (Franklin is a one way street) or Opera Plaza across from CPUC.

If you need to contact CPUC in the morning, please call Eugene Cadenasso at (415) 703-1214.

If you have questions or comments about the report or other elements of the project, please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x131.

Jennifer Tencati, Project Manager
I have reviewed the Administrative draft report “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities” (the Report) dated April 2010. Specific comments are presented below. Two general statements about the Report are:

1. The Report contains many generalizations and speculations that are not clearly related to preparation of a Programmatic Environmental Impact Report (PEIR) for anaerobic digesters at dairies in the Central Valley of California (CV).

2. The report lacks references to identify specific regulatory agency requirements applicable to the construction and operation of anaerobic digesters at dairies in the CV, and is unclear on how some identified regulatory requirements will affect the PEIR.

Please contact me to discuss those general statements or the following specific comments.

Page 5:

It is not clear how many digesters are currently operating at dairies in California. The Report states: “As of October 2009, 21 major anaerobic digester systems had been constructed and are currently operating within California.” The associated footnote states “In 2009 six operating digester systems have recently suspended or closed their operations due to financial difficulties or regulatory compliance issues.” Does that mean 15 digesters are currently operating at dairies in the State? Is there a reference that identifies those dairies?

Under “Covered Lagoon Digesters,” the Report states: “Covered lagoon digesters generally are unheated (mesophilic) and are not well suited for co-digestion.” Given that statement and the fact that lagoon systems have a potential to leak and thus pose a potential threat to water quality, under what conditions, if any, can covered lagoon digesters be used for co-digestion?

Page 6:

The Report states: “However, as result of recent imposed manure management regulations for Central Valley dairy farms, depending on their land and groundwater conditions, many farmers are required to construct more expensive Tier 1 lagoon systems. In such cases, the added costs for double lining or reinforcing the lagoons represent a significant additional cost and will make complete mix and plug flow systems more attractive and cost-effective digester systems for biogas production.” That statement does not appear to be completely true. The effluent from complete mix and plug flow systems also needs to be stored in ponds prior to application to cropland, and lining requirements apply to those ponds too. Also, a reference should be provided to clarify what is meant by the term “Tier 1 lagoon system.”

Page 7:

Under “Centralized Digester”, the Report states: “Only a few studies have assessed the economic feasibility of centralized digesters within the United States,” and identifies reports by Bothi, Reindl, and DeVore. However it does not identify a report titled “Clustering of Independent Dairy Operators for Generation of Bio-Renewable Energy: A Feasibility Analysis Report” dated 31 July 2006 and prepared by Sean Hurley, James Ahern, and Douglas Williams of the California Polytechnic State University - San Luis Obispo. That report appears relevant and should be listed and discussed.
Also, there is no discussion of nutrient management associated with centralized digesters. The centralized site must apply the digester effluent to sufficient cropland to accommodate the nutrients in the effluent, must return the nutrients to the feedstock origin site, or must market the nutrients to farmers or other end users. The cost for the selected option must be considered as part of the economic feasibility of centralized digesters.

Page 8:

Under “Electrical Generation”, the third paragraph states: “Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas,” and then, relative to emission of oxides of nitrogen (NOx), states: “Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas, conforming with 9 - 11 ppm (NOx) is infeasible with the current available technology… although others state that existing systems such as the SCS-Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm.” The paragraph should be rewritten to clarify that the statement about 9 - 11 ppm NOx being infeasible is applicable to IC engines, but not to micro-turbines. Also, if it is determined that, even with exhaust treatment, IC engines cannot realistically meet the NOx emission limits, then there should be some discussions on how the inability to use IC engines for producing electricity from biogas affects the feasibility of siting digesters on dairies.

Page 10:

Given the limitations (see Report Page 8) that apply to using biogas for on-site production of electricity, information about the Vintage Dairy should be evaluated relative to characteristics of other dairies. With the need to clean up biogas and the need for the digester to be near a natural gas pipeline, under what conditions (based on experiences at the Vintage Dairy) do biogas injection projects appear feasible? Approximately how many dairies in the Central Valley meet those conditions?

Page 14:

Under “Digestate Use Values,” the Report states: “digestate can be spray applied to crops as a fertilizer supplement / replacement, (or) used as compost material or livestock bedding material.” As defined in the Report, digestate is a high-solids material and cannot be spray applied. It should also be noted that the use options for digestate are essentially the same as for manure prior to digestion and that digestate cannot be used directly on crops intended for human consumption.

The Report also states “Currently, single crop farming in the region can typically accept approximately 2,000 lbs of manure or digestate per acre annually while double cropped fields can receive 3,000 lbs per year… the quantity of digestate that will remain after anaerobic digestion will be approximately… 1,200 lbs per cow per year” and cites “Clear Horizons, 2006” as an information source. I could not locate the identified report (“Clear Horizons, Craven Brothers Farm Digester Project Feasibility Study, January 2006”) on the internet in order to assess the basis for that statement. The statement makes it appear that the manure produced by five cows will fertilize two acres of double-cropped land. That ratio is inconsistent with application rates typically used in California. When assessing application rates, it is necessary to evaluate the amount of nitrogen and other nutrients applied to land, not the mass of manure produced. The information should be reassessed and the paragraph rewritten as necessary to be accurate.
The Report states “Some analysts argue that most digestate uses should not be recognized as an additional revenue source unless manure or other feedstocks (if co-digestion is occurring) has been imported (Hall, 2010).” Importing feedstocks will result in costs to manage the resulting increased volume of digestate, and those costs may offset any increased revenues from marketing the digestate. For example, although digestate solids can be sold and exported, digestate liquids (effluent) will likely remain at the digester site and will result in increased costs (for access to additional cropland) to manage. The report should be modified to discuss both the pros and cons of managing digestate associated with imported feedstocks.

Under “Effluent Use,” there is a similar discussion about imported feedstocks, but the Report does identify the need to have sufficient cropland (“onsite capacity”). However, subsequent paragraphs state “the high costs of fertilizer ensure that effluent can have reuse value to the dairy and other nearby farms” and “it can be reasonably expected that on a per cow basis, new net effluent gains would have some positive revenue value for the dairy.” Given the limitations of digester effluent (potential pathogens, transportation costs, etc.), those statements should be qualified.

A subsequent paragraph states “effluent treatment to separate out the nitrogen, phosphorous and other salts could generate highly valuable organic fertilizer byproducts” and then notes “Such an additional effluent processing component… would be costly.” The Report should be edited to clarify which technologies associated with operating a digester at a dairy actually exist and are practical to implement.

Under “On-site Electrical Generation,” the Report states: “It is currently unclear whether the use of on-site electrical generation equipment can be cost-effectively applied in the near term for dairy digester systems in the Central Valley… given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically infeasible in the Central Valley until major improvements in the technical capabilities and costs for new microturbines or fuel cells are achieved.” If on-site generation of electricity using an IC engine powered by biogas is infeasible in the CV, the Report should clearly present that situation and not discuss on-farm electricity production that cannot be accomplished.

Report Table 2 “Capital Costs For Dairy Digester Developments In California” has a column listing “Capital Cost ($/kWh).” It is unclear how the values shown were developed; they do not in all instances equal the value obtained by dividing the corresponding “Capital Cost” by the “Annual Energy Production” value.

The Report states: “CVWB estimates that a typical 1,000 herd dairy produces approximately 3,600 tons (dry weight) of manure per year containing 180 tons of nitrogen.” That value does not appear to reflect nitrogen losses that occur during storage, treatment, and application. The value should be updated using current CVWB records using actual nitrogen production and application data.

The Report states: “Unless, landowners can prove that their farm’s specific site conditions will not result in water quality impacts, the primary compliance approach will be construction of more expensive Tier 1 lagoon systems.” As previously noted, a reference should be provided to clarify
what is meant by the term “Tier 1 lagoon system.” Also the Report should discuss the process that landowners should follow to assess the site-specific conditions.

The Report states: “Currently, the CVWB is in the process of completing a comprehensive salinity management program with the State Water Board to address salinity problems within the Central Valley. However, until the new plan and program is completed, there are no general salt standards. Consequently review of dairy farm waste discharge compliance plans are performed on a case by case basis and the salt impacts of co-digester digestate are poorly understood, making it more difficult and costly for dairy farmers to comply with the water quality requirements. Given that the PEIR will be completed before the “new plan and program” are completed, the Report should provide additional information on how to assess salt management relative to digesters.

The Report states: “While exportation of solid manure and/or digestate to other farms is permitted with little water quality regulatory oversight, a similar transfer of digestate effluent requires the recipient farm to comply with the WDR manure management testing and verification procedures.” The regulations that require a recipient farm to comply with the WDR manure management testing are not identified. Also, there is no reference to the Irrigated Lands Regulatory Program that can impose requirements on the use of solid manure or digestate on cropland. References or additional information should be provided to clarify what specific regulations apply to the use of solid manure and digestate and the use of effluent that is exported.

The Report states: “In particular, wet system digesters (e.g., covered lagoons) that can not use all their digestate on site will likely have to reduce the water content of their effluent if the dairy farmer needs to export some of the material to meet the water quality standards.” No discussion of any practical way to reduce water content of effluent is provided. Either a reference or excerpt should be provided or the suggestion deleted as being impractical.

Page 33:

The Report states: “Mr. Norman also provided a list of suppliers of equipment that may be able to satisfy the District’s BACT requirement for NOx from power generating equipment that combusts biogas.” The associated citation is a 4 February 2010 e-mail “to Tim Morgan at ESA.” The list should be incorporated into the Report.

Page 36:

The Report states: “There is considerable hope within the renewable resource industry that fuel cells, “micro-scrubbers,” or other new technological improvements may be possible that could reduce unit production costs for biogas and/or biomethane production or enable affordable on-site electrical production that complies with air quality requirements.” That statement and subsequent statements in the same section do not appear to contain factual information useful in developing a PEIR. The Report should focus on topics directly applicable to development of a PEIR and not present opinions and predictions that are not supported with currently available data / facts.
From: Ramon Norman [mailto:Ramon.Norman@valleyair.org]
Sent: Wednesday, April 28, 2010 8:20 AM
To: Jennifer Tencati
Subject: Quick Comment On Email about difference requirements

Hello,

I have one quick comment related to the 2010 email that I sent regarding requirements for dairy digesters in the San Joaquin Valley Air District. I was trying to get the email out quickly and made a mistake. In the email I accidently said that the 8-hour ozone standard was revoked but actually the 1-hour ozone standard was revoked and replaced with the 8-hour standard. Please correct this so that everyone has accurate information regarding the current ozone standard. Thanks

Ramon Norman
Air Quality Engineer
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg Ave
Fresno, CA 93726-0244
Phone: (559) 230-5909
FAX: (559) 230-6061

Healthy Air Living
www.healthyairliving.com
Make one change for clean air!

5/4/2010
From: Freeman, Andy [mailto:Andrew_Freeman@irco.com]
Sent: Wednesday, April 28, 2010 12:34 PM
To: Jennifer Tencati
Subject: RE: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Jennifer,

Thanks again for the opportunity to participate on the TAG. Please distribute the attached to the author of the Economic Feasibility Report, Nick Carlson of ESA.

My intention in making these comments is to provide present day accurate information about microturbines, emissions, costs, turbine inlet cooling to boost efficiency, and overall economic viability. This is based on 2010 product and market research, Ingersoll Rand operating site data, and feedback from banks and financiers that we are engaged with to invest in our San Joaquin Valley dairy digester gas to energy projects.

I would welcome any questions, and I can be used as a reference in the report if needed, my full contact info is below.

Respectfully,

Andy Freeman
National Sales Manager
Ingersoll Rand Energy Systems

From: Jennifer Tencati [j.tencati@circlepoint.com]
Sent: Tue 5/4/2010 11:39 AM
To: Paul Miller
Cc:  
Subject: FW: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report
Attachments:

https://exchange.csassoc.com/exchange/PMiller/Inbox/FW:%20Dairy%20Digester%20Mo... 7/24/2010
Hi Andy,

We did not have a court reporter at today's meeting, but we did take notes. I will talk with the project managers to confirm we'll be sending those out and let you know.

If you have any comments to the Economic Feasibility Report, you may send them to me and I will make sure the appropriate project team members have copies.

Thank you,

Jennifer

Jennifer Tencati
Jennifer,

Thank you for providing the link. I had to disconnect from the line 30 minutes in. Is there a transcript or recorded version available?

Also...I am interested in providing written comments to the Economic Feasibility Report in order to update the accuracy of information regarding microturbines. Where should I send these comments so that they get implemented?

Thanks,

Andy
Dear TAG members,

In follow up to our third TAG meeting today, we have arranged for a call in number for the 10:30 a.m. call on Monday, April 26th to discuss the Administrative Draft Economic Feasibility report (attached).

https://exchange.csassoc.com/exchange/PMiller/Inbox/FW:%20Dairy%20Digester%20Mo...  7/24/2010

Appendix A-18
The call in number is: (605) 475-4900

ID number: 501775#

You may also join the meeting in person. It will be held at CPUC’s San Francisco office at 505 Van Ness Avenue in the Golden Gate Room.

You may enter the building on Golden Gate Avenue, next to the ATM machine and go directly to the Golden Gate Room.

Parking is available on the street (metered) or at a lot on Golden Gate and Franklin (Franklin is a one way street) or Opera Plaza across from CPUC.

If you need to contact CPUC in the morning, please call Eugene Cadenasso at (415) 703-1214.

If you have questions or comments about the report or other elements of the project, please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x131.

-Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

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KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Prepared for the
California Regional Water Quality Control Board, Central Valley Region

April 2010
KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Prepared for the
California Regional Water Quality Control Board, Central Valley Region

April 2010
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Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-digester Facilities

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KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Executive Summary

Extensive research and review was conducted on published industry analyses on anaerobic digestion and the use of dairy manure for bioenergy within California and elsewhere within the United States. Numerous factors are identified as key contributors influencing the future economic viability of the potential development of dairy manure digesters and co-digesters within the Central Valley. The factors determined to be important economic drivers (both positive and negative) are summarized below:

- **Energy Prices.** Most fundamentally, current and projected future commodity prices of natural gas and electricity are critical revenue constraints for dairy digesters. Natural gas is a readily available substitute for dairy digester produced biogas and biomethane. Consequently, most potential customers will be unlikely to buy biogas or biomethane at prices much above their commodity price for natural gas. Similarly, the value of biogas generated electricity will be limited by the prices of utility supplied power alternatives. Currently, long term natural gas and electricity prices are not forecast to increase (adjusted for inflation) due to recent discoveries of new domestic shale gas reserves. Consequently, biogas can not expect substantially improved feasibility from future commodity price escalation.

- **Air Quality Regulation of On-site Electrical Generation.** On-site generation of electricity represents a potential direct, “lower tech” and inexpensive beneficial use option for biogas. However, air quality restrictions within the Central Valley may preclude this use. If cost effective compliance technologies or mitigation can be developed, digester systems could be greatly enhanced – especially if adequate feed-in tariffs or other utility support increases the revenue potential for small scale distributed energy production.

- **Public Sector Support.** Federal and state grant funding, low interest loans and other public sector support (e.g., tax incentives and pilot programs) have played a vital role in past digester development. Both the amount and form of future public sector support can have a strong positive role in fostering manure digester implementation within the Central Valley. Future government support is expected to remain essential for continued development of manure digester systems.

- **Access to Capital and Third Party Developers.** The current financial difficulties facing most dairy farmers and the generally tight credit market will ensure that funding for digester developments will be scarce and costly for the foreseeable future. While increased participation by third party developers may provide some technical and financial assistance, private capital...
Key Factors Determining Economic Feasibility

will be relatively costly. The potential “capital crunch” constraints will be especially acute for those biomethane production projects that require major construction, involve new technical applications and/or supply biomethane to less established and developing non-utility markets.

- **Biogas Upgrading for Biomethane Production.** Biogas scrubbing and conditioning for biomethane production is currently costly and can only be cost effectively performed at production levels significantly greater than most individual dairy operations can support. Combined with biogas upgrade system costs, system design and location requirements represent key factors limiting the feasibility of digester biogas sales for the foreseeable future.

- **Role of Utilities.** Local utilities represent a key potential customer for surplus energy production from dairy digesters. Local utilities are the predominant energy producers and wholesalers in the market and therefore can most effectively and efficiently manage the sale, distribution and use of digester produced energy. Currently, utilities are understandably wary of such distributed energy projects since they represent emerging competition. In general, the administration of small scale production (from dairy digesters) provides limited financial return for utilities. Utilities also face regulatory restrictions that limit both their involvement and, most importantly, the prices that they can pay for dairy digester energy. However, innovative and constructive partnerships between digesters and utilities offer a key potential mechanism for greater and more cost-effective development of biogas as a renewable resource.

- **Technological Change.** Although many of the core digester and biomethane technologies are fairly well established, future commercialization of dairy manure digester systems may be expected to result in some cost effectiveness improvements. However, currently most foreseeable improvements appear to be incremental rather than fundamental. Consequently, most analysts suggest that per unit production costs for biomethane and related electrical generation will remain higher than commodity energy prices and hence public support for production will remain necessary. Key technology breakthroughs that could dramatically improve future dairy digester profitability include cost-effective on-site electrical generation with biogas (e.g., very low emission micro-turbines or fuel cells) or inexpensive and/or farm sized biogas upgrading systems.

- **Proximity to Feedstocks and Energy Markets.** The location of potential dairy digester and co-digester systems can be critical to the facility’s ability to obtain sufficient manure (and possibility feedstocks for co-digesters) and/or supply its biogas and other facility products to potential buyers at an attractive price.

- **Permitting.** Facility development design and permit costs to comply with state and local regulations can represent major delays, risks and financial expenses that may discourage potential digester development.

Many other factors will also contribute to the profitability of dairy digester systems. Generally, the effects of the other factors are relatively minor compared to the economic drivers identified above. For example, many analyses have investigated the potential for revenues gains from digester byproducts (e.g., digestate sales), tipping fees (for co-digester), or the environmental attributes of anaerobic digesters (renewable energy credits and carbon offsets) as important feasibility factors. However, the magnitude of these often speculative revenues will remain secondary to the value of the digester’s primary product, which is biogas.
Introduction

The technological feasibility of biogas production from manure digesters and co-digesters is well established. Generally, digester produced biogas has been used for on-site generation of electricity and/or heating to meet the farm needs. Farm digester systems typically can produce three or four times the amount of energy that their farm’s need. This surplus biogas production represents a significant renewable energy resource with considerable potential economic value and environmental benefits.

However, to understand and evaluate the economic and environmental trade-offs associated with future manure digester and co-digester systems in the Central Valley of California, the key factors determining the economic feasibility need to be determined. Three basic types of economic factors can be identified: revenue factors, cost factors and implementation/development issues.

The balance and interrelationships of these factors under the specific project circumstances will determine the project’s overall feasibility. Most simply stated, if the average revenues (i.e., on a per unit basis) are greater than the digester’s average cost of production, then the project will have a positive benefit-cost ratio and will, in a basic sense, be economically feasible. However, to fully assess the project’s feasibility, implementation factors should also be considered to determine the likelihood that successful future development can occur.

Revenue and costs naturally face tradeoffs in the project’s feasibility as increased costs are usually necessary to generate higher revenues. The key for improving a project’s feasibility occurs when the marginal revenues are greater than the marginal cost required for the revenue growth.

Each factor will have both technical and financial components determining the magnitude and nature of its effect on the system’s feasibility. Generally, economies of scale associated with greater production efficiencies will result in a lower production cost per unit. Similarly, at a fixed rate of production, higher sale revenues (or reduced production costs) will increase the revenues per unit. In both cases, the system’s economic feasibility will be improved.

The following analysis provides a brief description of the key factors affecting the economic feasibility of digester systems. The nature and extent of each factor’s contribution or role to the economic feasibility is also identified and evaluated. The central purpose of the analysis is to identify those economic or technological “drivers” that play a major role in determining the viability of digester system development. Expected future trends that might alter the system’s overall economic feasibility are discussed.

The analysis generally discusses manure digesters and unless explicitly noted otherwise, should be read as also applicable to and inclusive of co-digester systems. In addition the report maintains an important distinction between biogas and biomethane. Biogas is generally synonymous with raw biogas (i.e., the unrefined biogas produced by anaerobic digesters that has a methane content of 50 to 65 percent). Biomethane refers to refined biogas with higher methane content, typically 95 percent or more.

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1 Except in cases where equipment of facility requirements or cost / revenue thresholds may result in a “step-function” cost.
Finally, it should be noted that this analysis primarily addresses “economic” feasibility issues and as such considers the general costs and benefits of manure digesters. Strictly speaking, “financial” feasibility analysis typically refers to a more specific and comprehensive determination of the revenues and expenditures for a well-defined and site specified project. As such, a financial feasibility analysis would typically provide a more detailed description and estimates of project costs and revenues, consider its business cash-flow and include greater characterization of applicable market conditions and other considerations – primarily from the perspective of the potential owner/investor.

Nonetheless, financial and economic factors are often used interchangeably. Unless specified otherwise, references to financial issues will refer to a more general economic assessment of cost and revenue issues.

The economic feasibility for specific systems will depend not only on general feasibility factors but may also depend upon site- or system-specific considerations. Nonetheless, important general observations can be identified and assessed.

Revenue Factors

The revenues generated by a future digester are central for its economic viability. Typically, it is more difficult to estimate future revenues than it is to estimate future costs which are easier to specify. This is particularly true in the case of a new or emerging market (e.g., such as biomethane) where the potential customers and future product applications are difficult to identify and fully evaluate.

The following section provides a brief overview and assessment of the various factors that will influence the potential revenue performance of future anaerobic digester development in the Central Valley of California. When possible, the relative magnitude and any significant future revenue variables are also reported so that those factors that are current and future revenue “drivers” can be identified and their inter-relationships with cost and implementation better understood.

Biogas Productivity

The efficiency and effectiveness of biogas / biomethane production of manure digesters and other related production processes is a central factor in determining economic feasibility. All else being equal, greater biogas production will increase the system’s revenue potential and hence cost-effectiveness.

Currently, most dairy digester produced biogas is used on-site for energy generation. Electrical production is generally the primary use of the produced biogas although heat is frequently also produced for use in the anaerobic digester either as part of a combined heat and power system (CHP)\(^2\) or separate dedicated boiler systems. Consequently many of the feasibility studies for manure digesters report their productivity and costs in terms of the system’s electricity production.

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\(^2\) The thermal energy recovered in a CHP system can be used for heating or cooling farm facilities. Since CHP captures the heat that would otherwise be lost in traditional electrical generation, the efficiency of an integrated system is much greater (up to 85%) than the separate systems combined efficiency (45%) (ACEEE, 2010).
Overall System-wide Estimates

There is a wide variance in the methane and electrical production rates estimated for manure power systems. The potential biogas production will not only depend on the anaerobic digestion process used but also on both the volume of biodegradable organic materials in the collected manure and the length and type of manure collection and storage used. Similarly, the amount of electricity that can be produced by the digester system will also depend on the electrical generation system used.

The California Energy Commission (CEC) conservatively estimates an average 36 cu.ft. of methane per cow\(^3\) per day (with an energy content of 36,000 Btu/day) which can generate 0.107 kWh of electricity. The EPA estimates that manure digesters can typically produce 38.5 cu.ft. of methane per cow per day (EPA, 2004).

Actual daily electrical generation performance at Hilarides Dairy was substantially less at 0.055 kWh per cow (though partly due to substantial biogas flaring during the evaluation period) (WURD, 2006). Craven Farms reported achieving daily energy values of 34,500 Btu/cow with a 0.096 kWh per cow electricity generation rate that is comparable to CEC estimates. Other studies suggest 0.14 kWh per cow (Electrigaz, 2008), and 0.1 kWh per cow (Black & Veatch, 2007) as reasonable daily electrical productivity projections. Other analysts have more optimistic estimates of the per cow energy values. PG&E has estimated that each cow may generate 1,640 kWh annually (equivalent to 0.187 kWh per cow).

Within these biogas production parameters, it is generally agreed that adequate biogas capacity can be attained by larger dairies for development of dairy digesters to be technically feasible, and to be potentially economically viable with sufficient revenue assistance.

Specific Digester Systems

**Manure Digesters**

Three primary anaerobic digester system approaches are commonly used to treat dairy manure. The system most suited for a specific dairy operation will generally depend on its manure management system. As of October 2009, 21 major anaerobic digester systems had been constructed and are currently operating within California.\(^4\) The digester systems vary from relatively small dairy farm facilities processing the manure wastes for approximately 200 head of cattle to very large dairies with up to 5,000 cattle.

- **Covered lagoon systems** are the most basic and traditionally the most inexpensive anaerobic digester systems to construct and operate. These systems require the manure to be highly diluted (typically with a 3% or less total solid content) roughly consistent with “flush” manure handling. Covered lagoon digesters generally are unheated (mesophilic) and are not well suited for co-digestion with other feedstock. The average retention times for processing the manure is 45 to 60 days. The biogas conversion rates for covered lagoon

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\(^3\) Whenever possible, production and cost projections have been normalized for a 1,000 lb dairy cow.

\(^4\) In 2009 six operating digester systems have recently suspended or closed their operations due to financial difficulties or regulatory compliance issues.
systems are generally 35% to 45% (Burke, 2001). Covered lagoon systems are currently the most widely constructed and operated dairy digester systems in California.

- **Complete mix systems** consist of a tank constructed of either reinforced concrete or steel. The digester contents are periodically mixed and frequently heated to maintain an optimal temperature for methane production. As a result, complete mix systems are more expensive to construct and require applied energy to operate. These systems work best with slurry manure with a total solids content of 3% to 10%. As a result they can be used by managed flush manure management dairies or scrape manure dairies if water can be added to the collected manure. Complete mix systems are well suited for co-digestion and have a relatively short retention time of 15 to 20 days. Consequently they are also able to handle higher processing loads. Heated digestion (thermophilic) with a complete mix system can be expected to increase biogas conversion rates to 45% to 55% (Burke, 2001). Currently, there only a few complete mix digester systems are operating within California.

- **Plug Flow Digesters** consist of a long relatively narrow tank often built below ground. The digester requires semi-solid manure (i.e., with a total solid content between 11% and 13%) consistent with “scrape” manure management systems. Plug flow systems can be operated heated or unheated. The costs and biogas conversion rates for plug flow digesters are comparable to similar complete mix systems. Typical retention time for plug flow digesters are 20 to 30 days (Burke, 2001). Also, plug flow digesters are less well suited for co-digestion use. Currently, 6 plug flow digesters currently operate or recently operated within California.

Until recently, the price performances of these three digester systems were roughly comparable. The higher biogas production from managed digester systems (i.e., complete mix and plug flow) covered the additional construction costs. As a result, the costs per cow for these systems were approximately the same (Martin, 2010). However, as result of recent imposed manure management regulations for Central Valley dairy farms, depending on their land and groundwater conditions, many farmers are required to construct more expensive Tier 1 lagoon systems. In such cases, the added costs for double lining or reinforcing the lagoons represent a significant additional cost and will make complete mix and plug flow systems more attractive and cost-effective digester systems for biogas production.

Wider adoption and commercialization of digester systems may be expected to reduce system costs and improve performance – both from facility design improvements and better system management. However, the biogas productivity improvements will be relatively limited and incremental.

**Co-digesters**

The biogas productivity of dairy manure digesters can be greatly increased by the addition of other non-manure organic feedstocks. The proportional increase in biogas production will depend on the quality and suitability of the added feedstock. Food or agricultural wastes with higher oil or grease contents will generally release a greater amount of methane than other feedstocks with lower potential energy values. There is considerable variation amongst analyses in the amount of additional methane that co-digesters can produce. A conservative analysis for the CEC observed approximately a 35% improvement in methane production by co-digestion (CH2M Hill, 2007). Other commenters suggest that high energy feedstocks (e.g. fats, oils and greases or municipal...
organic wastes) could result in a doubling or even tripling of biogas production by dairy digesters (Hintz, 2010). Such industry analysts projected that the potential for major gas productivity improvements (supplemented by tipping fee revenues with longer term contracts for handling the municipal green wastes) will make a substantial improvement in the economic feasibility of biogas production (Best, 2010).

Co-digestion is more management intensive and could add greater reporting and oversight requirements to comply with water quality and solid waste regulations. However, the additional equipment costs for enhanced production should be minor (presuming the feedstock handling, preparation and storage requirements are limited). Consequently, many analysts suggest that co-digestion can provide cost effective biogas production gains.

However, availability of suitable feedstock will be important for determining the practicality and cost effectiveness of co-digestion. Many analyses identify potential tipping fee revenues for the digester operator from the feedstock sources as an important additional revenues source. However, as discussed later under the discussion of by-product revenues, most potential agricultural wastes are only seasonally available and may be located too far from specific digesters to be cost-effectively transported. Feedstocks also may become a commodity so that co-digester operators will likely have to obtain a variety of different feedstocks.

**Centralized Digester**

Only a few studies have assessed the economic feasibility of centralized digesters within the United States. Feasibility studies for centralized digester systems in New York state, southern Wisconsin and Oregon concluded that the proposed systems were uneconomical (Bothi, 2005; Reindl, 2006; DeVore, 2006). Analysis for a centralized manure digester in Dane County, Wisconsin projected significant cost efficiencies compared to individual systems but still required major public and private sector support.

A few large centralized manure digesters have been constructed and operate in the United States. The Inland Empire Utilities Agency’s (IEUA) Chino Basin project in South California was the first centralized anaerobic digester to be developed in the United States and is the only centralized digester facility currently operating in California. The IEUA project came online in 2002 and processes 225 tons of manure per day from 6,250 dairy cows, plus food waste from local food industries. The manure is trucked to the facility from six farms located within 6 miles of the digester (Davis, 2009).

However, currently all of these centralized digesters are in effect demonstration projects having received major funding assistance and have faced significant operational difficulties. The Chino Basin facility itself received approximately $5 million of its $8.5 million construction cost from the USDA’s Natural Resource Conservation Service (NCRS) for watershed protection. The CEC provided approximately $2 million in funding with the remainder provided by the Inland Empire Utilities Agency (IEUA) that owns and operates the facility. The energy generated from the biogas powers the agency’s off-site groundwater desalinization plant and wastewater facilities.

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5 It is presumed that co-digestion will not substantially alter the value or use of the resulting digestate except for the negative aspects from potential net nitrate and salt increases associated with the feedstock importation to the dairy.
Large scale biomethane production requirements are a primary rationale for centralized digester systems. Although there are potential limited economies of scale for the centralized digester, manure transportation and handling costs can offset the economic savings if there are not sufficient suitable dairies willing to participate in close proximity to the proposed facility. Given the limited and geographical constraints on such facility’s economies of scale, the centralized digester systems represent a secondary factor for digesters’ economic feasibility. Currently, there are only limited future system enhancements foreseen that would improve their cost-effectiveness.

**Electrical Generation**

Electrical generation is currently the primary use of digester biogas within California. Biogas (and biomethane) can be used to generate electricity using a variety of technologies including reciprocating engines (e.g., such as internal combustion), microturbines, gas turbine and fuel cells. Electrical generation with digester gas represents a promising distributed generation (DG) technology offering not only the environmental benefits of offsetting fossil fuel use but also has the additional benefit of destroying methane which otherwise would have major greenhouse gas impacts.

Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in the determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. This emission standard has been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards.

Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, currently properly operated “clean burn” IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations (Joblin, 2010). While additional selective catalytic reduction can in some cases be used to further reduce emissions, the necessary secondary emission controls are expensive and difficult to operate on lower energy fuels such as unrefined biogas. Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 - 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the SCS-Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010).

Microturbines are a newer technology that is becoming increasingly available. While potentially well suited for low emission electrical generation using biomethane, microturbines generally do not operate well under hot climate conditions (e.g., such as during summer months within the Central Valley). Recent implementation efforts at dairy digesters have been mostly unsuccessful as...
reliability issues could not be solved for on-farms (Dusault, 2010). Analysts also suggest that at comparable implementation scales, the thermal conversion efficiency of microturbines will typically be 5% less than internal combustion (IC) engines.

<table>
<thead>
<tr>
<th>TABLE 1</th>
<th>COMPARISON OF ELECTRICAL GENERATION TECHNOLOGIES FOR BIOMETHANE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Factors</td>
<td>Microturbines</td>
</tr>
<tr>
<td>Cost ($/kW)</td>
<td>$300 - $1,000 / kW</td>
</tr>
<tr>
<td>Commercially Available</td>
<td>Yes</td>
</tr>
<tr>
<td>Size Range</td>
<td>30-500 kW</td>
</tr>
<tr>
<td>Efficiency</td>
<td>20 – 30%</td>
</tr>
<tr>
<td>Emissions</td>
<td>Low (&lt;9 – 50 ppm) NOx</td>
</tr>
<tr>
<td>CHP Possible</td>
<td>Yes</td>
</tr>
<tr>
<td>Commercial Status</td>
<td>Small Volume Production</td>
</tr>
</tbody>
</table>

All dollar amounts in 2007 dollars. SOURCE: California Energy Commission; ESA.

Combustion turbine engines are a mature technology but scale issues for their implementation preclude their use with dairy digesters except for the relative large or centralized community systems. At the lowest end of the scale, at least 5,000 dairy cows would likely be necessary to generate sufficient biogas production. The conversion efficiencies for combustion turbines are also expected to be reduced at the scales likely to be applicable for any on-site or community system.

Fuel cell technology is currently at an early stage of development and consequently the costs for fuel cells are many times greater than for comparably sized micro-turbine, turbine or IC engines. Even though the efficiency of fuel cells are considerably better than the other technologies, given this very large production cost differential, until major technological improvements and/or large scale commercialization is achieved, fuel cells will remain dramatically less cost-effective for implementation.

EPA estimates that the maximum thermal conversion efficiency of biogas to electrical output by a standard reciprocating engine (internal combustion) is 28.5%. However, due to the difficulty in sizing engine-generator sets for optimal efficiency as well as a likely on-line operating condition, electrical output for biogas is estimated to be 66.6kWh / 1,000 cu.ft. of methane. Consequently, the thermal efficiency conversion to electricity is between 18% and 25%.

Electrical production with biogas will remain an important potential alternative use for digester systems. Consequently, the electrical generation productivity will have a direct revenue effect by determine the amount of energy that can be sold or used from the system. But, as discussed below, the reduced efficiency rates for biogas electrical generation compared to natural gas reflect the biogas's lower methane and higher impurities content.

9 The reduced efficiency rates for biogas electrical generation compared to natural gas reflect the biogas's lower methane and higher impurities content.
other factors such as pricing structures with local utilities will have a greater influence on the system’s overall economic feasibility than its electrical generation performance. However, it is possible that major technological advances could provide major improvement in the cost-effectiveness and/or environmental performance of future biogas electrical generation systems.

Commodity Prices of Energy

Natural Gas

Generally speaking, biomethane is a more valuable energy commodity to utilities than biogas generated electricity since the biomethane can be more readily stored for later use. Consequently, it is easier for utilities to use the biomethane as an energy resource during periods of higher energy demand (i.e., when its value as an energy resource will be higher).

In a fundamental way, the commodity price of natural gas constrains the economic value and sale price for digester system produced biogas and biomethane. Natural gas is a substitute energy alternative for on-site biogas use, off-site commercial sale or upgrading to biomethane. If the renewable and environmental attributes of the produced biomethane are considered separately (i.e., Renewable Energy Credits [RECs] and greenhouse gas [GHG] credits), then the core value of biomethane will be largely limited to the substitution cost for potential purchasers (e.g., such as industrial users or utility) to use natural gas to meet their energy needs.

In past years, the price of natural gas has fluctuated greatly. The price variability had been partly due to the major international oil price fluctuations and global economic instability. Current natural gas prices are approximately $5.40 /1,000 cu.ft.10 Extensive future supplies of domestic natural gas are currently believed to be available and ongoing technological improvements in natural gas recovery are expected to enable natural gas production to increase over the next 25 years. During that period, natural gas prices are expected to remain unchanged in real terms (USEIA, 2010).

While long term stable natural gas prices (in real terms) are good for the general economy, the absence of any significant future natural gas commodity price increase will undercut the future economic feasibility of biomethane production. If the sales prices for biomethane are restricted to current natural gas prices, any future production costs increases can be expected reduce the profitability of biogas production unless offsetting technological improvements are achieved.

Currently, biomethane pipeline injection is only permitted into PG&E’s transmission pipelines due to insufficient and inconsistent demand within its distribution network. Furthermore, to meet the utilities flow requirement, any biomethane injection to the transmission pipeline must occur near urban areas that have adequate and consistent natural gas demand.

An initial pilot project at the Vintage Dairy near Fresno is currently operating and processes manure from approximately 3,000 cows into biomethane. The dairy has successfully upgraded its biogas to meet PG&E’s gas quality requirements. Vintage Dairy is located along a natural gas transmission

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10 City Gate Price for November 2009 (U.S.E.I.A, 2010).
line and therefore in able to inject on-site. In PG&E’s experience, biogas injection projects more than 4 to 5 miles from a transmission pipeline are less economically viable (PG&E, 2009). Other studies and analysts have also concluded that proximity to interconnection locations are a major limiting constraint for the feasibility of biomethane pipeline injection (Goodman, 2010). Consequently, the existing natural gas transmission system infrastructure is considered a key feasibility constraint for future development of any dairy biomethane pipeline injection within the Central Valley.

Biomethane could potentially be piped to local industry or commercial customers with sufficient energy needs. Again however, due to the relatively high cost of construction for delivery pipelines, proximity to the biomethane production facility will be a key feasibility constraint. Furthermore there are likely to be only a limited number of industrial or commercial users with adequate power demand.11

Alternatively, biomethane can be compressed or liquefied for truck transportation and/or transportation fuel use. The biogas conditioning requirements for compression biomethane (CBM) or liquefied (LBM) are comparable to those required for pipeline quality biomethane although specific users or fuel use may accept higher carbon dioxide levels.12 As is discussed in the assessment of production costs, the purified biomethane must not only be compressed or liquefied, but on-site storage is also likely to be necessary until it can be truck transported to its end customers. Given their very similar chemical composition, the market prices for compressed CBM and LBM are expected to be highly comparable to compressed natural gas (CNG) and liquefied natural gas (LNG) prices.13

The commercial sales potential for CNG and LNG are currently relatively limited. However, CNG offers substantial fuel cost savings as prices are currently averaging approximately $2.25 per gallon gasoline equivalent compared to diesel’s current $2.70 per gallon gasoline equivalent (cngprices.com 2010; CEC, 2010). The current market is primarily focused on sales as a “clean” transportation fuel for vehicle fleets. While municipal or government agencies have been major initial adopters of CNG vehicles, private companies are also considered potential customers. Presently, the main operational limits to CNG powered vehicles use is their horsepower constraints which make them less well suited for trucking us over major gradients. The greatest market demand for CNG fuel is within California’s major urban areas where the negative air quality effects of diesel trucks are highest and the CNG supply infrastructure can be most cost effectively developed.

Although, there are existing and future sales opportunities for CBM and LBM, it remains an emerging market that is constrained by the higher cost of conversion or purchase of CNG/LNG powered vehicles and the need for expansion of the fueling infrastructure. Consequently, the value of both CNG and LNG are expected to remain closely related to natural gas prices with a relatively limited potential for any price “premium” for biomethane.

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11 Under some circumstance and pending local air quality issues, it may be viable for “raw” biogas to be used for industrial or commercial heating systems. In which cases, if the relatively costly biogas upgrading are avoided, it could be economically viable to pipe the biogas further distances to commercial customers.

12 Acceptance of higher carbon dioxide proportion will offer some production cost savings.

13 If the biomethane’s environmental attributes (e.g., renewable energy credits [RECs]) are valued separately. Given the nascent CBG and LBG markets it should be conservatively assumed that no major premium biogas price would be obtainable – especially given the relatively small production levels likely for the foreseeable future.
Electricity

Similar to natural gas, electricity prices have a central influence in determining the economic performance of digester systems. The “retail” electricity price that farmers currently pay to meet their on-farm needs determines a maximum economic value for their potential electric cost savings earned by self generation. The avoided cost for purchasing electricity at the utility’s retail price will offer direct economic benefit for dairies that can self generate electricity on-site to meet their electricity needs. Electrical generation for on-farm use and/or net metering plays a vital role in the economic performance of current operating dairy manure systems (PERI, 2009).

Net Metering

Retail electric rates in California are comparatively higher than elsewhere in the United States and consequently will increase the potential economic attractiveness of alternative energy sources. Currently, the typical base “retail” electricity price facing farmers within the PG&E service area is $0.12 kWh to $0.14 kWh. However, during peak periods electricity prices can increase to more than $0.25 kWh (PG&E, 2010).

In 1995, the California State Legislature passed SB 656 (Alquist), which required all electric utilities to buy back any electricity generated by a customer-owned solar and wind systems system. This buy-back program is known as “net metering” because the electricity purchases of the customer are netted against the electricity generated by the customer’s renewable system. The customer’s utility bill is calculated on the net quantity of electricity bought from the utility. However, the utilities were not required to purchase any surplus generated by the customer and it was only the subsequent Assembly Bills 2228 (passed in 2002) and 728 (passed in 2005) that required the utilities to offer net metering to dairy farms that generated electricity with biogas.

Past net metering regulations did not encourage digesters operating as electricity “exporters” since the program only allowed them to “bank” their energy production in the utility grid. As a result, biogas producers often chose to flare excess biogas rather than generate electricity for which they would receive no compensation from their local utility. In addition, dairy farmers do not receive the full retail price for their self generated electricity but still incur tariff charges for transmission and distribution, demand charges, public purpose funds. These additional costs can be considerable – averaging $0.055 / Kwh (in 2005 dollars) for a typical dairy (Krich, 2005).

However, recent passage of AB 920 has amended the net metering provisions to require utilities after January 2011 to compensate customers for any surplus electrical production. This improves the future revenue potential for dairy’s self-generating electricity.

Feed-In Tariffs

Following the passage in 2006 of Assembly Bill (AB) 1969 (and subsequent CPUC rulings), PG&E and other California utilities are now required to buy excess energy generated with renewable sources from qualified customers. Dairies that generate electricity can choose to sell their surplus...
electricity to their local utility under a Small Renewable Generator Power Purchase Agreement (PPA) provided they sell less than 1.5 MW of power (which at average of 0.107 kWhr / cow would be equivalent to surplus power production by 14,000 cows). This “feed-in tariff” program is in some ways a more sophisticated net metering program as the dairy’s usage and exports to the grid are both measured for quantity and by time of delivery. Under the feed-in tariff program, small renewable energy producers are able to obtain long-term contract for their energy production at a very low transaction cost which should assist in raising capital investment. This is a primary benefit offered by the feed-in tariff program to potential dairy digester developers.

Under the feed-in tariff program the purchase price for excess power is set by the CPUC according to the market price referent (MPR) determined as part of the State’s renewable portfolio standard proceedings. The MPR values offered under the feed-in tariff program are based on the comparable costs for electrical production at large scale utility power plants. As such, the MPR is unrelated to the actual cost of renewable energy production and therefore does not provide any subsidy to encourage specific renewable resources.15

The prices paid for the surplus power is also adjusted for its “time of delivery” which recognizes the higher value of power supplied during on-peak periods and its lower value during off-peak hours. Current MPR values are approximately $0.09/kWh and producers can enter into 10, 15 or 20 year contracts with the utility (PG&E, 2010).

The feed-in tariff programs provide an improved mechanism for dairy digester to sell surplus electricity. However, the set price for the MPR price and low off-peak rates can nonetheless result in average electricity prices that may be insufficient to fully compensate for the electrical generation system costs. Furthermore, the long term contracting terms lack escalation provisions and this can be a disincentive for electrical producers deciding between participating in the feed-in tariff or net-metering programs. However, it may also be possible with suitable gas storage and design that a digester system could be operated beneficially as a peak power operation under the feed-in tariff program so that the dairy sells most during peak or partial peak periods (PERI, 2008).

While the feed-in tariff program improves the revenue potential for on-site electrical production, it does not maximize the economic benefits to the dairy. Under the current feed-in tariff programs, Californian utilities are prohibited by regulation from “wheeling” electricity from the dairy – even amongst the dairy’s own electrical accounts. For example, a dairy farm with several electrical accounts (e.g., for refrigeration, irrigation systems, lighting and home use) will have to sell the power in excess of that it consumes on its producing electrical line (i.e., that connected to the generator system). Under the PPA agreement terms with the utility, the dairy would earn revenues (which may be near to a wholesale price) while at the same time being charged at a higher retail price for the electricity it is consuming on its other electrical accounts. Under this arrangement,

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15 Some industry experts suggest that the MPR is too low to provide sufficient financial support for the development of new renewable energy projects. Consequently, the CPUC is currently also considering the implementation of “reverse auction” as future funding. If approved, potential renewable energy producers could bid the rates at which they would supply electricity. The major utilities would then select the lowest cost bids from qualified producers. Such an approach could enable the producers to contract for renewable energy at higher than MPR rates.
the dairy loses some of its potential avoided cost savings that it could earn if it was able to fully
serve its own electrical needs from its own electrical production.

The feed-in tariff program is available on a first-come, first served basis and PG&E’s obligation
for the program serving manure digesters and other non-water/wastewater customers will end when
104.6 MW of installed renewable generation will operate under the program. As of February 2010,
only the Castelanelli Bros Dairy has enrolled in the program (PG&E, 2010).

The most recent analysis by the CEC predicts that California’s system-wide average retail electricity
price will not increase in real terms between 2010 and 2016 (CEC, 2007). If electricity prices
remain stable, then there will be reduced economic incentives for on-site electric generation use
of dairy digester biogas.

In summary, electricity prices are a direct and fundamental driver of dairy digester feasibility. The revenue boundaries for digesters systems are determined by both the retail prices paid by
electrical consumers and the wholesale prices and contract terms by which utilities will purchase
any on-site surplus electrical production using biogas / biomethane. The terms of any feed-in tariffs,
PPA and other price factors (e.g., time of delivery pricing) will determine and incentivize the dairies’
production levels and use/sale of their biogas. Currently, much of these terms are set by the CPUC
regulations and policy which determine not only the MPR but also authorize the utilities’ prices to
its consumers and their ability to “pass on” any electrical purchase costs. Similar to other distributed
generation and renewable resources, these financial factors may be expected to have an important,
albeit complicated role, influencing the economic feasibility for manure digesters in the Central Valley.

**Byproduct Values**

*Digestate Use Values*

Most feasibility studies of dairy digester systems estimate an economic value for use of the digestate
by-products. Depending on its water content, the digestate can be spray applied to crops as a
fertilizer supplement / replacement, used as compost material or livestock bedding material.

The quantity and form of the digestate will be related to the anaerobic process used. Lagoon digesters
will result in predominately liquid digestate while the complete mix digesters typically produces a
denser slurry digestate. The plug-flow process results in a wet solid digestate material. The digestate
can be heated or otherwise dewatered to separate the solid fraction for use as a compost material or
bedding. If a dairy farmer has insufficient land to accept all its digestate, the material can generally
be transported short distances to other nearby farm operations. In many cases, the digester owner
will earn a small payment for the effluent (Martin, P., 2010)

The extent that the digestate by-product can be used as a soil supplement or fertilizer replacement
will depend on the farmland soil conditions and crop types as concerns about salt and nitrate loading
limit its land application rates within the Central Valley. Currently, single crop farming in the region
can typically accept approximately 2,000 lbs of manure or digestate per acre annually while double
cropped fields can receive 3,000 lbs per year. Given that a cow will produce approximately one
ton (2,000 lbs) of manure solid a year, the quantity of digestate that will remain after anaerobic digestion will be approximately 60% or 1,200 lbs per cow per year (Clear Horizons, 2006).\(^{16}\)

Some analysts argue that most digestate uses should not be recognized as an additional revenue source for the digester since the dairy’s manure would otherwise be similarly reused on-site. In which case it may be argued that no new net revenue has been generated unless manure or other feedstocks (if co-digestion is occurring) has been imported (Hall, 2010).

In any case, the potential value of avoided bedding costs will be very minor. Although bedding sales of digestate are commonly estimated to be approximately $20 - 25 per ton (Clear Horizons, 2006), according to USDA statistics, less than 0.28 percent of the total dairy budget was spent on bedding and litter materials for the average California dairy operation (USDA, 2005). Consequently the avoided cost of digestate use for bedding or revenues from their sales can be expected to have a minimal if not negligible effect on the economic feasibility of any manure digester systems.

The compost value of digestate is considered to be potentially significantly higher if it can be sold commercially.\(^{17}\) Green waste recyclers report sales of up to $18 per cubic yard ($90 per ton) (SAIC, 2002). However, wholesale values of the digestate may be far lower. In an analysis of a large centralized digester system Hurley estimates that the net value of the digestate would be $5/ton which was consist with several other studies (Hurley, 2007).

Again, given the relatively minor net value of the bulky digestate and recognition that it is arguable that any net material gain has occurred (and in actuality likely to have been a 40% loss in biomaterial material weight in the manure to digestate conversion), the value of the solid digestate as a compost revenue may be expected to have a minimal contributory effect to the digester feasibility.

**Effluent Use**

Digester effluent is typically applied to dairy farmers’ fields for feed crop production. As discussed above for the solid digestate, it is arguable whether any revenues or avoided costs associated with the use of the effluent by-product will represent a net revenue contribution. Unless organic feedstock material has been imported (which would increase the effluent quantity and/or fertilizer value), then the farmer’s fertilizer expenditure would be expected to relatively unchanged. Consequently, only co-digesters or centralized manure digester systems would be expected to generate net revenues from digester effluent use that would represent additional revenues potentially improving the project’s feasibility. Furthermore, if the location of the digester has insufficient onsite capacity to accept on-field applications of all the generated effluent (or solid digestate), then disposal of the effluent could add costs that would further decrease the project’s economic feasibility.

The potential applied fertilizer cost savings with effluent use will have greater potential economic than solid digestate uses. Furthermore, unlike the quantity of manure solids which is substantially

\(^{16}\) Assuming substrate volatile solid content of approximately 65% (i.e., manure with bedding) of which 60% would be converted to methane.

\(^{17}\) Technically, the digestate is not actually compost material since it has not been aerobically decomposed, however it has very similar uses and nutrient value for soil application as compost.
Key Factors Determining Economic Feasibility

reduced by the anaerobic digestion process, most of the nitrate, phosphorus and, to a lesser extent, potassium content will remain in the effluent and digestate. As a result, any use of imported feedstock will likely add additional nutrients. While such nitrogen and other salt accumulation can present potential water quality concerns if improperly managed, the high costs of fertilizer ensure that effluent can have reuse value to the dairy and other nearby farms.\(^{18}\) Farm studies indicate that the fertilizer value of untreated manure can be significant – conservative estimates from a 1997 study estimate the annual value of untreated manure to be over $100 / cow (in 1997 dollars) (Hart, 1997). However, these fertilizer cost saving are also more applicable to higher value commercial crops rather than feed crops. Nonetheless, it can be reasonably expected that on a per cow basis, new net effluent gains would have some positive revenue value for the dairy.

It has been suggested by some industry analysts that large scale effluent treatment to separate out the nitrogen, phosphorous and other salts could generate highly valuable organic fertilizer byproducts that would be suitable for use by drip feed irrigation systems. Such an additional effluent processing component to the dairy digester facility would be costly with developer costs and economies of scale similar to those necessary for biogas upgrading systems. However, given the high costs for fertilizer purchases, the high concentrate organic byproduct would have significant value which according to some experts could be a major economic driver for the digester system (Best, 2010). Furthermore, such a digester effluent treatment system would sequester nitrogen and salt thereby improving the dairy’s water quality management practices.

In general, net effluent gains for co-digesters or community digester systems may represent a positive albeit relatively minor supplemental economic factor for system feasibility (subject to local farmland soil conditions).\(^{19}\)

**Tipping Fees (Co-digesters only)**

Most co-digester studies argue that that tipping fees for the feedstocks processed by co-digesters are important revenue sources. Several studies have concluded that tipping fees can be crucial factors is determining the viability of the digester project (Moffatt, 2007).

However, it is essential that the net revenues for sourcing co-digester feedstocks are understood so that the net revenues to the digester project can be correctly determined. “Tipping fees” generally refer to the price paid for disposal of the organic wastes. In some cases, the waste producer may also incur additional transportation costs for removal of the waste. Co-digester operators sourcing feedstocks for their facilities will similarly need to recognize the costs for transportation (and possibility storage) of the feedstock to determine the cost-effectiveness of feedstock additions for their biogas production.

In most cases, waste-to-energy facilities are able to obtain a disposal or tipping fee for feedstocks that increase biogas production and add revenues that assist in offsetting facility construction and operating cost expenses. Such disposal fees currently range from about $50 to $60 / ton in California.

\(^{18}\) It should be noted though that the site-specific soil and groundwater conditions may reduce the effluent’s value if the land application rates of local farmland are too restrictive.

\(^{19}\) Not including the development of major effluent processing component.
However, most of the feedstocks are potential commodities for which supply, demand and prices are susceptible to change. Relatedly, most commercial feedstocks (e.g., agricultural or food processor wastes) are expected to be available only seasonally and on a short-term contract basis. Digester operators will likely have to obtain a variety of different feedstock materials from numerous sources. Municipal green waste is currently identified as one of the more reliable potential feedstocks. As competition increases for these resources this trend may reverse and tipping fees may decrease.

Costs for collection, transporting and storing agricultural residues uses are typically in the range of $25 to $50 per dry ton. Transportation costs of $0.20 to $0.60 per mile per ton are typical for feedstock delivery (Jenkins, 2006). Other analyses have identified loading and unloading costs of $0.40 / ton (2007 dollars) with a $0.18 / ton / mile transportation cost (Moffatt, 2007).

Tipping fees can offer additional revenues for co-digester systems but transportation and storage costs may reduce the net revenues for the digester operator. Given the uncertainties and geographic considerations associated with current and future feedstock commodity values, it is conservatively considered that tipping fees should be recognized as at most a minor secondary supplemental revenue source solely for co-digester systems.

**Greenhouse Gas Emission Reduction Credits**

There are two types of potential greenhouse gas (GHG) credits that many be derived from digester systems: (1) Credits for methane destruction (carbon offsets); and (2) Credits for Fossil Fuel Displacement (renewable energy credits).

Methane has 23 times the greenhouse gas impact of an equivalent weight of carbon dioxide (CO₂). Consequently, each ton of methane that is intentionally destroyed will have an equivalent GHG reduction value of approximately 23 tons of carbon dioxide. Use of renewable fuels for power generation also has a secondary benefit that carbon currently stored in fossil deposits is not added to the environment. Renewable Energy Credits (RECs) in effect account for the fossil fuel displacement effects and are discussed separately below.

A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” (i.e., the offset provider must prove that the project would not have happened without its financial investment and that the project goes beyond “business as usual” activity).

The methane collection and use associated with anaerobic digesters systems can result in considerable reductions in GHG releases. Flaring of collected biogas will result in a net GHG impact reduction as the more volatile methane is converted to carbon dioxide which has less than a twentieth of the climate change effect. Productive use of anaerobic digester biogas will result in additional GHG benefits as the biogas generated energy will reduce the corresponding utility generated GHG emissions that would otherwise be necessary.
Currently, there is an emerging international and domestic market for greenhouse gas emission offset credits (often referred to as carbon credits). Both the European Union (EU) and Chicago Stock Market (amongst others) operate “carbon markets” for the purchase and sale of certified carbon credits. In addition, potential GHG credits have to be certified to verify their effectiveness. Numerous organizations operate GHG verification programs both within the U.S. and internationally (e.g., the Voluntary Carbon Standard Association and Gold Standard Foundation). Within California, the California Climate Action Registry (CCAR) has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters.

Presently participation in GHG markets is voluntary within the United States. Nonetheless, many businesses are currently purchasing carbon offsets to support projects that reduce GHG levels. Consequently sales of carbon offsets may be an additional revenue source for future digester projects. However carbon offset prices are subject to market conditions and price volatility. Between 2005 and 2007, carbon reduction credit values were as high as $50 per ton of CO$_2$ equivalent. More recently, carbon values have been considerably lower - typically in the range of $10 per ton. Since the market is based on both the supply and demand for carbon credits, it is difficult to project the future carbon credit values.

PG&E currently operates its Climate Smart program which allows participating customers to elect to pay an additional monthly premium to fund CPUC-approved projects that reduce GHG emissions. Climate Smart acquires 1.5 million tons of carbon credits annually and as such is the largest single carbon credit purchaser in California. Residential, businesses and municipal customers participating in the Climate Smart program are purchasing GHG offset credits which fund renewable energy purchases and development. PG&E estimates a current carbon reduction price of approximately $7 per metric ton of CO$_2$ for its Climate Smart program. Given an annual GHG impact equivalent to 4.6 tons of carbon per year, the current potential carbon offset value for qualified dairy digesters would be approximately $32 per cow (Brennan, 2009).

A central issue for carbon credits is “additionality.” Additionality considers whether the GHG reduction is discretionary and whether the carbon offset purchase actually ensures carbon reductions, or whether the reductions would have occurred regardless. If the carbon offset purchase is a key factor in making the reductions happen, the reductions can be considered to be “additional” to the business-as-usual case. If anaerobic digesters become the Best Available Control Technology (BACT) for dairies’ waste management, then digester collection of methane would no longer represent “additional” carbon reductions and so would no longer qualify as carbon credits. Under such circumstance, existing GHG credits would remain valid until the end of their ten year term but new credits would not be authorized (CCAR, 2007).

**Renewable Energy Credits**

Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.
Renewable Energy Credits (RECs), as statutorily defined, are not created until electricity is generated. Therefore biogas digesters, unlike wind turbines and geothermal facilities, in and of themselves have no RECs to convey. However, if the digester biogas end use will replace the use of fossil fuels for energy production then the digester can qualify for fossil fuel displacement credits.20 As a renewable resource that can directly substitute for natural gas use, biomethane or biogas used for electrical generation or injection into the utility grid will qualify for REC credits.

The value of the fossil fuel credits also depends on the fossil fuel use that would be displaced. Consequently, California fossil fuel displacement credit values for electrical generation use are lower than elsewhere within the most of the United States due to the fact that no coal fired power plants operate within the state. Under the State of California’s Renewable Portfolio Standards (RPS) requirements, there is an emerging market for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters. The generation of renewable energy from the dairy digester systems can be quantified and certified for sale as a renewable energy credits.

A digester system developer retains the RECs for self-generated power used on site while the utility receives the remaining REC credits for any surplus electricity it has purchased. Utilities and other entities that need these “green tags” to comply with California’s Renewable Portfolio Standard would be potential purchasers of digester RECs. In addition, other businesses wishing to support renewable energy might also be interested in purchasing digester power RECs. REC prices are subject to market conditions but could be expected to be $0.002 to $0.005/kWh (CH2M Hill, 2006).

Currently, most RECs within California are sold bundled with the associated renewable energy. Consequently, utilities such as PG&E that are negotiating long term renewable energy purchases acquire the REC values with the resource’s material value as a fuel. Consequently, the sale price for the renewal resource has a price premium component for the included REC. However, the REC values for self-generated energy used by the dairy will be retained and would be potentially available for sale and purchased.21

There are no established REC values for biomethane use as a transportation fuel. However, future implementation of the California Low Carbon Fuel Standard (LCFS) is expect by many industry experts to encourage the future of REC values applicable for future use of biomethane (either as CBM or LBM) as a replacement for diesel and gas fuel (Price, 2010). Although very difficult to value at this point in time, some industry experts maintain that the future REC values for biofuels could add additional revenues for digesters systems producing CBM or LMB.

**Other Economic Benefits of Sustainable Farm Production**

Currently, several of the farms with operating digester systems receive significant attention for their pioneering sustainability improvements and use of biogas as a renewable energy source. Hilarides Dairies use of cow power for its trucks and Fiscalini Farm’s use of its biogas for its

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20 Consequently, biomethane production for use as transportation fuel will not qualify for RECs.
21 The sale and purchase of tradeable REC’s for utility compliance with RPS is currently under agency review and consideration by the CPUC.
cheese production are two notable examples. Similarly, the Straus Family and Gallo Farms also differentiate their dairy operations by their implementation of more sustainable farming practices.

However, as yet there is no appreciable market or economic value to these and other California dairies rewarding them for adopting more sustainable business practices. While “greener” businesses in other sectors may be able to leverage their sustainability commitments for an improved market position or marketing benefit, there is currently little potential for dairy farms to capture any such similar benefits. Due to California’s regulated milk sales market and relatively few dairy producers that sell directly to retailers, most dairy farmers are “price-takers” (LaMendola, 2010). Dairies such as Straus Family Farms that have a brand identity and sell their dairy goods to consumers are very few in number and represent a very small portion and niche of the dairy market. Premium prices for “greener” dairy producers are unlikely to be achievable in the foreseeable future particularly during a depressed economy and relatively low public awareness of the potential for more sustainable production practices such as dairy digesters. Furthermore, due to the largely consolidated market for most dairy goods and the perishable nature of milk itself, emergence of any sales premium or selection preference for dairy products from “sustainable” dairy farmers will likely require a considerable increase in prevalence and/or accreditation labeling (i.e., a “green” stamp of approval) before wholesalers and/or other large customers can and will begin to select amongst dairy producers for those more sustainable producers.

As a result, it is considered unlikely that dairy farmers will be able to gain any significant economic premium for their dairy products from their digester operations.

**Government Grants and Assistance**

Currently most operating digester systems receive considerable government funding assistance. Anaerobic digester projects qualify for many of the federal and state programs promoting renewable resource development. Governmental assistance and support can be provided in the form of form grant funding, low-interest loans, tax incentives and/or technical support. The main forms of government support currently available for biomethane production by dairy manure digesters are identified below. Individual digester projects will have to qualify for assistance on a case by case basis and projects will typically receive assistance from only a few programs.

*Renewable Energy Production Tax Credit.* Under this federal program authorized by the 2005 Energy Policy Act, qualifying renewable energy producers can obtain $0.015/kWh in production incentives. The program is currently authorized to continue until 2026.

*USDA – Renewal Energy Program.* The program provides grants and loan guarantees to rural small businesses and agricultural producers for up to 25% of the cost to purchase and install renewable energy generation systems up to $500,000.

*Self-Generation Incentive Program for Renewable Fuel Cells.* Authorized by the CPUC, this utility administered program provides financial incentives for installation of new, self-

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22 The Feed-in Tariff program authorized by the CPUC is discussed previously under the electricity price section.
generation equipment installed to meet all or a portion of the user’s electric energy needs. The program was originally designed to complement the CEC’s Emerging Renewables Program (ERP) by providing incentive funding to larger renewable and non-renewable self-generation units up to the first 1 MW in capacity and subsequently increased for units up to 3 MW in capacity. Renewable fuel cell systems can receive a $4.50 /watt as a one time capital payment (but not to exceed 50% of the total cost). Non-renewable fuel cell systems can similarly receive a $2.50 /watt capital payment.

California Energy Commission - Renewable Energy Program. The Existing Renewable Facilities Program provides production incentives, based on kilowatt-hours generated, to support existing renewable energy facilities. In addition, the Emerging Renewables Program provides rebate funding for solar and fuel cells that use renewable fuels (such as biogas). The program has $65.5 million in funding until 2011.

State Assistance Fund for Enterprise, Business and Industrial Development Corporation: Energy Efficiency Improvements Loan Fund. This long standing state program offers low interest loans to small businesses in California for renewable energy systems. The maximum loan amount is $350,000 at 4% interest with a five year repayment period.

In addition to these current programs, the State of California (administered by the CEC) provided significant funding assistance to manure digester and other similar renewable resource projects through both its former Dairy Power Production Program and research conducted under its Public Interest Energy Research Program (PIER). As discussed previously in the Renewable Energy Credits discussion, the State of California Renewable Portfolio Standards (RPS) requirements also provides indirect support for manure digesters by fostering an emerging market within California for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters.

Recent economic analysis of dairy digester systems installed under the California Dairy Power Production Program determined that without government subsides, even the best constructed / operated digesters would have electrical production costs that are “high tending to be above market rates” (PERI, 2008). Even factoring in government subsides, the cost of energy for other digester systems were such that while several digesters were marginally profitable, several others operated at a negative rate of return.

Together these past and current programs illustrate the important role that state and federal programs contribute to fostering the development of manure digester systems. The financial and technical support is widely agreed to be an important and positive influence improving the feasibility of manure digester development. Furthermore, given the increasingly complex regulatory conditions facing dairy farms and renewable energy projects, as well as the financial challenges remaining before full commercialization of the manure biogas/biomethane production is expected to occur, continued governmental support is expected to remain an important and essential economic driver for future manure digester development for the feasible future.
Cost Factors

These costs typically will consist of both:

- Initial construction and equipment costs for development of the digester project. In many cases there may be significant economies of scale as the system capacity increases. The construction and/or equipment cost will also likely vary depending on the technology adopted.

- Operating and maintenance cost for the project. This will include the labor and input costs including required energy. Typically, these are variable costs and will vary with the level of production. The operating and maintenance cost may also vary depending on the technology adopted.

The following section identifies the major cost factors that influence the economic feasibility of biogas production by dairy manure digester systems. These factors are naturally inter-related with the revenue factors discussed above. Just as market conditions will determine the revenue potential for digester biogas and its other byproducts, technological and equipment supplier conditions will be key cost determinants on economic viability. Consequently, major technological improvements that greatly decrease unit production costs will enhance the economic feasibility of dairy digester development. Conversely, additional equipment / processing requirements (i.e., as result of new regulatory compliance requirements) that increase unit production costs will reduce the dairy digester system’s economic viability.

As will be discussed below, economies of scale can have an important role determining unit production costs and consequently the economic feasibility of the system. In some cases, scale issues will be limiting factors. Major equipment components may require minimum quantities of process throughput to operate adequately and in such cases these technological/operational constraints may dictate system design parameters.

Finally, it is worth noting that costs are generally easier to estimate than revenues which typically face more future variables. This is particularly apparent when the digester system’s operating assumptions and conditions are defined. Review of past digester studies offer far greater cost information than is provided for their revenue projections. In any case, care should be taken to ensure that estimated costs are properly matched with operational / output assumptions. It should also be recognized that site specific conditions can both positively or negatively affect the actual system development costs considerably.

Manure Collection / Preparation as Feedstock

The dairy manure collection costs for on-farm digesters are considered to be negligible since similar manure management practices are already a necessary component of existing dairy operations. Furthermore, the transportation distance within the farm will be very limited. In addition, relatively little pre-digester preparation is expected to be necessary for the manure. Any grinding or filtration necessary will be very minor in cost compared to the digester itself.
For a centralized or community digester system, manure transportation costs may be a limiting factor that could offset economies of scale that might be gained from larger anaerobic digester facilities. Manure from the individual farms could either be piped to the centralized digester through a sewer system or possibly be transported by trucks. Analysis by Ghafoori and Krich suggest that development of a piping system for dairy manure is prohibitively high from a construction cost basis (Ghafoori, 2005; Krich, 2005). Furthermore, such systems would incur major additional investment cost and could face significant additional difficulties with site and easement requirements.

**Anaerobic Digester Systems**

As discussed previously, anaerobic digester systems are relatively simple and well established technologies. Although there is potential for future productivity improvements, construction specifications and costs are relatively well defined. Most of the system components are relatively standard and readily available. Other construction costs (e.g., such as siting and land preparation) will be relatively straightforward.

The selection of specific anaerobic digester technologies will be primarily determined by the dairy’s manure management systems. While site specific requirements may necessitate some tailoring of digester configurations, construction costs should be relatively comparable between dairies located within the region. As a relatively simple and mature technology, future equipment and development costs for anaerobic digester systems are not expected to change substantially. Future technological improvements are expected to be predominantly incremental. Therefore, while digester system construction costs will represent a secondary factor in determining the economic feasibility of manure digester systems, this cost factor is expected to remain relatively constant and therefore represents a minor economic driver.

Operating and maintenance costs for digester systems remain largely under-analyzed. If feasibility studies consider the system operating and maintenance costs at all, most typically attributed a percentage cost of the project’s construction cost. While improved remote sensing and automated control systems can assist digester management tasks, many industry analysts agree that most studies do not fully recognize the labor likely involved to operate digester systems (Summers, 2010).

In any case, given the comparative simplicity and mature technology used for manure digester systems, operating and maintenance costs may be expected to make a very minor contribution to the digester overall economic feasibility. Furthermore, no significant cost improvements can be expected to the anaerobic digester process that would substantially improve overall system feasibility.

**On-site Heat/Boiler System**

On-site heat generation from biogas is predominantly used for heated complete mix or plug flow anaerobic digester systems. Otherwise, unless major milk processing is occurring on-site, most dairy’s heating demand will be relatively limited and can be met with standard boiler systems that can be fairly easily modified for use with biogas (although air quality compliance may be problematic). The capital cost for conversion or purchase of suitable heating systems will be relative minor. In most cases, heat generation will be limited and only a secondary use for dairies of any produced
biogas. Therefore, heating use of biogas will have a very minor influence on the digester’s economic feasibility. Furthermore, no major technological improvement or future significant cost savings can be expected related to biogas heating systems that would improve overall system feasibility.

If on-site electrical generation with biogas is planned, combined heat and power (CHP) designs typically can offer cost effective opportunities to use thermal energy that would otherwise be lost. However, given most farm’s limited heating needs it likely that surplus heat would still be generated. Consequently, while their may be opportunities for cost effective efficiency gains, the magnitude of the economic benefits will remain minor and will not be expected to be a significant economic driver of system feasibility.

**On-site Electrical Generation**

As discussed above, on-site electrical generation has generally been the primary use of biogas produced by on farm digester systems. Except for the Vintage Dairies facility which is producing biomethane for pipeline injection, all the other manure digester systems operating in California are using their biogas production to produce electricity on site.\(^{23}\) Electrical generation with internal combustion (IC) engines is a very well established technology that can be applied at both the full range of production scales and under a wide variety of operating conditions. Generally speaking, outside California, electrical production with internal combustion engines can be cost effectively performed to meet not only all on-farm needs but also to generate surplus electrical energy which can be exported to other users or to the grid under net-metering or distributed power arrangements with local electrical utilities.

The national average on-site electrical usage for dairies is 550 kW / cow / year (Barker, 2001). At a typical retail energy cost of $0.12 kWh, the annual electrical cost for each dairy cow would be $66. If it is conservatively projected that each dairy cow can generate 0.1 kW/hr, then an annual basis total value of the potential electrical production would be 876 kW/cow/year which would be worth approximately $105 per year per cow of which approximately $39 per year would be the potential value of the surplus electricity at average retail electricity prices.

Yearly operation and maintenance costs for electrical generation systems are typically estimated to be in the range of $0.015/kWh (Jewell et al., 1997; Hurley, 2007) which reduces the system operator net revenues/saving.\(^{24}\)

However, as discussed in more detail below, future electrical generation with biogas at dairies within the Central Valley is highly problematic due to recent air quality regulations that prohibit IC engine use unless NOx emissions can be reduced to 9 – 11 ppm or less. It is currently unclear whether the use of on-site electrical generation equipment can be cost-effectively applied in the near term for dairy digester systems in the Central Valley.

\(^{23}\) Hilarides Dairy also produces compressed biomethane with some of its digester biogas for use as a biofuel by its specially converted trucks.

\(^{24}\) Although as discussed under the Electricity price section, under the net metering program additional tariff costs for transmission and distribution, as well as demand charges may also be incurred. In addition, the interconnection process prescribed by CPUC Rule 21 can also require additional costs to the dairy.
On-site generation of electrical power is an important potential use option for dairy digester biogas/biomethane. As a form of distributed power, such on-site systems offer possible direct economic benefits and reduced overall environmental impacts. However, given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically infeasible in the Central Valley until major improvements in the technical capabilities and costs for new microturbines or fuel cells are achieved.

**Biogas Upgrading**

The fundamental purpose of biogas upgrading is to increase the proportion of methane from its 50 to 65% concentration to near pure methane (95-99%) while removing the corrosive H\textsubscript{2}S and CO\textsubscript{2} impurities.

The specific gas quality standards for biomethane to be accepted into the PG&E natural gas system are set in PG&E Gas Rule 21.C and by Rule 30 requirements for SoCalGas. Key utility specifications include less than 1% CO\textsubscript{2} and 4 ppm of H\textsubscript{2}S content.

The upgrading requirements for biomethane production to pipeline injection standards are comparable (and typically higher) than those required for CBM or LBM production. Therefore the primary economic differentiators between biomethane uses (e.g., pipeline injection, compressed biomethane or liquefied biomethane) will be associated with subsequent delivery and market requirements for the different uses.

There are three main processes necessary for refining biogas into biomethane. The technologies for each of the procedures are well established and widely used but generally are implemented at a scale far larger than the production levels that even large dairy digesters would be able to attain based on its own herd size.

**Scrubbing (H\textsubscript{2}S removal)**

Hydrogen sulfide (H\textsubscript{2}S) is a highly corrosive impurity within biogas as it readily combines with water to form sulfuric acid. Generally, H\textsubscript{2}S concentrations in raw biogas are typically 0.5% or less and can be problematic for many gas uses. However, for “lower tech” applications (such as boiler systems or internal combustion engines) regular and increased maintenance can be used to cost effectively manage most of the potential corrosion effects. Of the numerous potential scrubbing processes, iron sponge scrubbing is generally considered the most suitable for on-farm H\textsubscript{2}S removal (Krich, 2005).

**Conditioning**

Water removal from biogas to condense the water content is a relatively straightforward process. Using a relatively inexpensive commercial refrigeration unit and minor parasitic energy loss (2%), the water content in the biogas can be adequately reduced to acceptable levels.
Carbon dioxide is the most critical and expensive impurity to remove from biogas. Due to its relatively inert chemical composition and high concentration levels within the digester biogas, more extensive gas treatment is necessary for carbon dioxide removal. Water scrubbing is a relatively simple and low cost conditioning that is considered suitable for on-site dairy use. Although less efficient than other “higher tech” approaches, water scrubbing is most environmentally benign. Alternatively pressure swing adsorption (PSA), amine scrubbing and other technologies are available which offer some advantages for some applications (e.g., compatibility with LBM) but also present cost or environment byproduct disadvantages.

Biogas upgrading is likely necessary for any off-site use of digester biogas. The processing equipment, and to a lesser extent, the operating and maintenance costs, required for biomethane production will add considerable cost to the digester system. As a result, the unit cost for the biomethane will be increased substantially. While increasing the size of production levels can help to lower the unit cost of production, the volume of production necessary for most applications of the scrubbing and conditioning equipment remain relatively high due to the fixed cost of the technology. Furthermore, diseconomies of scale may begin to be incurred if the digesters can not be favorably located and clustered. Several previous feasibility studies have suggested that biogas upgrading systems would need to process the biogas of 10,000 cows although other suggest that full production cost efficiencies for pipeline injection would require 30,000 cows (Goodman, 2010).

As a result, unless future technology improvements can cost-effectively scale down biogas upgrading systems, it is likely that current biogas upgrading technology requirements will remain a major factor restricting economic feasibility.

**Distribution / Transmission System**

The construction costs for biomethane pipelines can vary considerably. Typically pipeline costs are estimated to range from $100,000 to $250,000 per mile. While the operating cost for pipeline delivery will generally be very low, the initial construction will represent a significant additional investment cost – especially compared to tanker truck delivery. Given the comparatively high cost for pipeline delivery, it has generally been judged that pipeline delivery of biomethane for any significant distance will not be economically feasible. Some analysts suggest that at most one or two miles in most cases would be a limiting distance for pipeline use (Krich, 2005). Others maintain that up to five miles may be viable under certain conditions (Brennan, 2010).

Pipe line distribution costs also will play a fundamental role determining the feasibility of a centralized biogas treatment facility serving several dairy digester systems. Cost effective development of a centralized biogas treatment facility will require the farms’ digester systems to be clustered close together. Furthermore, the combined biogas production must be sufficient to ensure an adequate supply to attain the necessary economies of scale for cost-effective biogas upgrading. Otherwise, the pipeline transmission costs to import the additional biogas from more distant producers may place additional cost burdens that undermine the collective enterprise’s overall feasibility.

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25 PVC like pipe materials are also available for raw biogas transmission. However, as an even lower-grade and less valuable fuel it is will be less economically feasible to transport than the refined biomethane.
One advantage of pipeline injection for biomethane is that only limited on-site gas storage facilities will be necessary. CBM and LBM production will require both storage and truck transfer facilities. Standard and relatively inexpensive propane tanks can be used for low pressure biomethane storage (i.e., up to 300 p.s.i.). This is most suitable as intermediate storage of the biomethane output from the upgrading facility. Biomethane must be further compressed to 3,000 to 3,600 p.s.i. (i.e., equivalent to CNG pressure) for delivery and use as a transportation fuel. LBM has to be liquefied at pressures of over 5,000 p.s.i and maintained at low temperatures. Such high pressure storage is expensive and relatively complex to maintain.

**Pipeline Injection**

Currently, although California utilities are willing and able to purchase biomethane produced by manure digesters, the supplying dairy must provide all the facilities necessary to deliver pipeline quality biomethane to the utility’s natural gas transmission system. Furthermore, the dairy (or third-party developer) must also perform the scrubbing and compression of the biomethane as well as install and operate the metering equipment and pipeline tap (Brennan, 20010). In addition, proximity to the natural gas transmission line will also be a major limiting factor. As discussed earlier, pipeline delivery costs will likely ensure that any biogas/biomethane production facilities for pipeline injection will have to be located at most a few miles from suitable connection locations to the transmission line.

Biomethane producers injecting biomethane into the existing natural gas transmission pipeline will incur an interconnection cost. Interconnection costs to the biomethane producer will vary depending on the utilities being served. Recent estimates for the connection cost for biomethane injection into PG&E transmission system are $0.265 million for biomethane producers injecting less than 500,000 cu.ft. per day. SoCalGas will charge biomethane producers the same rates as those for a tradition natural gas interconnection. Projects injecting up to 1 MM cu.ft. / day will pay approximately $0.8 million to access the SoCalGas transmission system (Anders, 2007).

The connection costs for pipeline injection are considerable and will require a greater scale of production so that the added costs can be adequately distributed to result in a manageable unit cost basis. In any case, the utility connection costs will represent a significant factor reducing the potential economic feasibility of biomethane production from dairy digesters. Furthermore, pipeline injection use of digester biomethane will be geographically constrained due to the high cost for any pipeline or vehicle transport of the biomethane between the digester and suitable injection points which must be along the natural gas transmission system.

**Compression / Liquefaction**

Methane requires 5,000 psi for liquefaction and it requires major applied energy to attain. Compression of biomethane only to 1,000 psi requires approximately 207 Btu of energy to compress each 1,000 Btu – a considerable parasitic energy “loss” or cost of 20.8 percent (Hansen, 1998). This does not include efficiency losses associated with the compression engines themselves.

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26 PG&E will provide the pipeline tap and metering equipment for large suppliers (i.e. those delivering 500 M cu.ft. or more per day).
There are major scale constraints for liquefaction and distribution of biomethane. Due to the cryogenic nature of liquid biomethane, significant energy must be used to maintain the produced LBM at very low temperatures to avoid the liquid “boiling off.” The potential energy losses for storage of LBM can be significant. Therefore, industry analysts suggest that liquefaction facilities should at a minimum be sized to produce adequate LBM to fill a standard tanker truck (approximately 10,000 gallons) every three or four days to reduce on-site storage losses.

**Biomethane for Fuel Use and Conversion Costs**

In recent years, the State of California has conducted extensive analyses and taken several actions intended to encourage the development of alternative vehicle fuels including Executive Order S-06-06 and most recently Executive Order S-01-07 (the Low Carbon Fuel Standard) requiring a 10 percent reduction in the carbon intensity of transportation fuels by 2020. Currently, compressed natural gas (CNG) is used as a petroleum alternative for cars and other light use vehicles. In addition, liquefied natural gas (LNG) is also being developed as a fuel source suitable for heavier industrial vehicles. While new CNG and LNG vehicles are available for commercial purchase, the existing market is relatively small and these alternative fuel vehicles are more costly. In addition, some diesel and other vehicles can be retrofitted to use a natural gas fuel. However, the costs are considerable and even high-use vehicles will have a long payback period from an economic feasibility perspective.

Compressed biomethane (CBM) and liquefied biomethane (LBM) are both potential substitute fuels for CNG and LNG vehicles. However, as with the CNG and LNG markets, although demand has been growing, this alternative fuels market is still at an early stage of development. Currently the majority of CNG and LNG vehicle fleets belong to municipalities. While this may offer some opportunities for partnerships, these will be geographically limited and will have a very finite demand until wider public adoption of CNG or LNG occurs. In addition, greater adoption of CNG and LNG as alternative fuels also faces strong competition from ethanol and biodiesel, which to date have received considerable and greater federal and state support.

Currently, nearly all of the LNG within California is imported over land in its liquid form by truck. Therefore, until planned LNG terminals in Southern California are completed, LBM produced in the Central Valley could have a transportation advantage over LNG. However, it is unclear whether the magnitude of this transportation cost savings will outweigh the higher production costs currently projected for LBM.

Consequently, the market potential for CBM and LBM is far from assured and participation as a fuel provider will face additional production costs (vehicle conversion, possible development of on-site fueling infrastructure). Therefore, given the absence of clear market demand and purchasers, the feasibility of production of CBM or LBM for bio-fuel sale is uncertain since it is difficult to determine the likely market price that producers would actually be able to obtain.

**Overall Digester System Construction Cost Estimates**

As discussed above, the capital costs for manure digester systems’ construction and equipment costs will vary depending on both the size and configuration of the planned system. Irrespective,
even the simplest of manure digester systems are relatively costly. Table 2 shows the costs and grant funding obtained for nine dairy digester systems in California. The cost estimates include the electrical generation facilities.

### TABLE 2
CAPITAL COSTS FOR DAIRY DIGESTER DEVELOPMENTS IN CALIFORNIA

<table>
<thead>
<tr>
<th>Dairy</th>
<th>Digester Type</th>
<th>Size (kW)</th>
<th>Annual Energy Production (KWh)</th>
<th>Debt Capitalization</th>
<th>Grant Equity</th>
<th>Capital Cost (a)</th>
<th>Capital Cost (a) ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hilarides</td>
<td>Covered Lagoon</td>
<td>500</td>
<td>3,383</td>
<td>0%</td>
<td>40%</td>
<td>60%</td>
<td>$1,392,000</td>
</tr>
<tr>
<td>Cottonwood</td>
<td>Covered Lagoon</td>
<td>300</td>
<td>2,133</td>
<td>0%</td>
<td>31%</td>
<td>69%</td>
<td>$3,132,000</td>
</tr>
<tr>
<td>Blakes Landing</td>
<td>Covered Lagoon</td>
<td>75</td>
<td>253</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
<td>$392,000</td>
</tr>
<tr>
<td>Castelanelli</td>
<td>Covered Lagoon</td>
<td>160</td>
<td>1,135</td>
<td>0%</td>
<td>57%</td>
<td>43%</td>
<td>$1,123,000</td>
</tr>
<tr>
<td>Koetsier</td>
<td>Plug Flow</td>
<td>260</td>
<td>540</td>
<td>0%</td>
<td>0%</td>
<td>100% (a)</td>
<td>$1,537,000</td>
</tr>
<tr>
<td>Van Ommering</td>
<td>Plug Flow</td>
<td>130</td>
<td>489</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
<td>$973,000</td>
</tr>
<tr>
<td>Meadowbrook</td>
<td>Plug Flow</td>
<td>160</td>
<td>1,100</td>
<td>0%</td>
<td>45%</td>
<td>55%</td>
<td>$1,185,000</td>
</tr>
<tr>
<td>IEUA</td>
<td>Modified Mix Plug Flow</td>
<td>943</td>
<td>7,572</td>
<td>0%</td>
<td>1%</td>
<td>99% (a)</td>
<td>$14,543,000</td>
</tr>
<tr>
<td>Eden-Vale</td>
<td>Plug Flow</td>
<td>180</td>
<td>457</td>
<td>0%</td>
<td>37%</td>
<td>63%</td>
<td>$904,000</td>
</tr>
</tbody>
</table>

*a Capital Costs have been adjusted for inflation into 2010 dollar terms.
*b Koetsier and IEUA received their subsidies as 5 year production payment instead of grant funding.


Other studies report similar cost estimates for developing dairy digester systems. Recent analysis for comparably sized dairy digester systems in Vermont reported capital costs between $4,000 to $7,800 per kWh in 2010 dollar terms (Dowds, 2009). Similarly, the approximate initial total cost for developing a 400kW digester system at Fiscalini Farms in Modesto California was reported to be over $2 million, equivalent to more than $5,000 per kW in 2010 dollar terms (Gannon, 2008). However, subsequent additional design and development requirements resulted in a final system cost of approximately $4 million of which only $1.4 million was obtained from grant funding (Dairy Today, 2010). The Gallo Farms Dairy estimates that the cost of its 700 kW digester system was approximately $3.5 million in 2010 dollar terms which is equivalent to a $5,000 per kWh capital cost (Pacific CHP Application Center, 2010).

As discussed above, digester systems developed for production of biomethane will require considerable additional upgrading equipment to remove the CO₂ and other impurities. In addition, compressor and storage systems will be needed if liquefied or compressed biomethane is to be produced. If the upgraded biomethane is to be injected to the utility pipeline then pipeline injection may require additional on farm (and possibly off-farm) pipeline to the utility’s natural gas transmission line as well as interconnection, controls and monitoring facilities to ensure the quality of gas supplied to the utility.

27 As discussed earlier, new digester development for electrical production will incur substantially higher equipment costs as more expensive generation system are now required to meet subsequent and more stringent air quality standards limiting NOx emission to 9ppm.
As discussed previously, most current biogas upgrading systems require relatively high gas throughput volumes for optimal performance. Consequently, biomethane production will incur additional costs from both increased scale of production as well as the additional facility and equipment requirements. Industry experts currently maintain that at a minimum manure for 10,000 cows would likely be necessary (without co-digestion) to generate sufficient biogas to supply a biogas upgrade facility to operate efficiently. While dairy farms would not need to invest in electrical generation systems, there would nonetheless be major additional cost for farm-sized biomethane production. Preliminary cost estimates for the CEC project interconnection costs of $250,000 and pipeline costs of at least $50,000 for the existing California digesters (PERI, 2009). The cost for biogas upgrading facilities was estimated to vary from $400,000 to over $750,000 (depending on the plant capacity). The saving from the reduced electrical generation capital cost also varied greatly from as high as $800,000 for Hilarides Dairy to just under a $100,000 for other dairies. Excluding the Blakes Landing and Castelaneli Dairies which were 5 miles or further from a suitable utility connection site, the total net additional capital cost for pipeline injections was generally $500,000 to $700,000 higher than for on-site electrical generation (PEIR, 2009). The study also projected that there would be a 15 percent loss of the original biogas quantity by the upgrading process.

Although preliminary and specific to the existing digester systems, the PERI cost analyses demonstrates the considerable additional capital cost involved in dairy digester development for biomethane production.

**Implementation Factors**

**Farmer Interest**

Dairy production is the core business for dairy farm owners most of whom also must manage some feed-crop production on their farms. Modern dairy farm management is itself a complex business requiring considerable time and expertise to successfully manage milk production and maintain regulatory compliance. This is particularly true during recent years as a poor national economy has adversely affected the California Dairy industry. Although 2008 was a year of record production with high milk prices, in the first half of 2009 dairy producers faced increased production costs – partly from increased feed costs resulting from reduced production as many Midwestern crop farmers shifted their production to feedstock crops for bio-ethanol production. For the first quarter of 2009, the average cost of production for California dairy farmers was $18.51 / cwt. More importantly, as a result of overproduction and reduced foreign demand, milk prices fell by early 40 percent between 2008 and 2009 to $10.47 / cwt - their lowest level since June 2003.

Furthermore, feed expenses represent the majority of the dairy farmer’s cost. In 2005, nearly 58 percent of the average Californian dairy farmer’s total cost of production was spent on feed while less than 3 percent of the total dairy budget was spent on electricity, fuel and lubrications for the farm operations (USDA, 2005). Consequently, the potential direct energy and/or fuel cost savings

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28 For farms located 5 miles from a suitable transmission utility connection site the pipeline cost was $1 million.
29 Except for Hilarides Dairy which had an unexplained but very major cost saving (approximately $788,000 in 2007 dollars terms) for replacement of its electricity generation equipment.
from a digester will represent, at best, a very minor benefit to the farm’s budget and any such savings may be easily outweighed by any feed price changes.

Not only must dairy farmers be willing to accept the necessary investment and operating risk to develop digester systems, farmers must develop the technical capabilities and have sufficient professional interest in assuming the secondary occupation of biogas production (Sempra, 2009).

In the face of such volatility and adverse economic conditions, without clearly attainable net financial earnings, few dairy farmers may be expected to assume the additional costs, risks and responsibilities necessary to develop dairy digesters.

**Capital Availability**

The interest rate associated with the initial capital investment (and to a lesser extent managing the operations cash flow needs) will play an important role in determining digester feasibility. Low interest loans and favorable tax depreciation allowances can have an important contribution in reducing the loan repayment burden that a facility must support.

The useful project life for digester systems will have an important role in affecting the economic feasibility of proposed digester and related biogas treatment facilities. A longer useful life will increase the period over which the facility’s capital investment can be earned back. However, due to the interest and inflation effects to the capital investment, future earnings at later periods in a facility’s operations typically will have a lesser contribution to offsetting the initial capital investment.

There are two key factors determining the availability of capital for farm digester systems. First, the dairy farm’s financial situation will be a fundamental determinant of its ability to borrow capital. The amount of equity that a dairy has in its business, its cash flow and the amount of the loan required will determine the likelihood that the farmer can qualify for a loan. Given the recent financial challenges facing the Californian dairy industry, it is expected that few dairies will be able to qualify for the necessary loans from commercial banks to fund the development of major digester facilities.

In addition to the dairy’s financial position, commercial banks must also be willing to provide the loans. Given the currently tight credit market facing the entire economy and the dairy industry’s current poor market conditions, it may be expected that many banks will be unwilling to provide lending for digesters – especially under relatively favorable terms.

Therefore, due to the challenges facing the dairy industry and the generally weak credit market, few dairies are expected to be in the financial position to fund digester development.

**Third Party Developer Assistance**

Third party developers can be expected to be important for the development of future on-farm or community digester facilities within the Central Valley. As discussed above, most dairy farmers are likely to be unwilling or unable to develop manure digesters systems themselves. Third party developers will likely be better able to collect and manage the investment and have the expertise necessary for effective digester development. The ability for third party developers to negotiate
and manage favorable Small Renewable Generator Power Purchase Agreement (PPA) with utility companies is also likely to be a key advantage for future digester system development.

The commercial interest rates and the related return on investment (ROI) sought by private developers will be important determinants of the economic viability and future development of digester facilities in the Central Valley. The ROI that developers will apply to digester systems will be a function of both commercial interest rates and the profit and risk premiums associated with any digester facility venture. The risk facing developers can be reduced by favorable market conditions (e.g., long term contracts with utilities or other biogas/biomethane consumers) and will also be related the supply conditions (such as the extent that the production technology and equipment is well established, widely adopted and/or transferrable to other commercial uses).

Due to the technological, market and regulatory risks associated with biogas/biomethane production, the returns on investment that potential venture capitalist or other third party developer will seek from any digester investment will be significantly above the returns required for other more established industries or businesses. Within the energy industry, potential investors typically seek payback periods of three to five years (Cheremisinoff, 2010; Best 2010). Within the published digester feasibility studies, the payback periods and return on investment rates applied vary considerable – partly given the differences between financial feasibility analyses (reflecting commercial investors’ profit requirements and capital terms) and economic feasibility studies (that represent agency or public policy perspectives) where the cost of money will be substantially lower and profit earning not applicable. Recent analyses for the California Energy Commission have applied rate of return estimates of 17% for their feasibility analyses (PERI, 2008).

While third party developer participation may be an important component of future digester development, their participation is fundamentally a reflection of the economic feasibility of dairy manure digesters and market context. Consequently, they may be considered to play an major role but will be an indirect economic driver since its will be the fundamentals of other market conditions that will determine the role and extent of their participation in the future digester development within the Central Valley.

**Environment Compliance and Regulatory Requirements**

In general, dairy operators face increasingly stringent state environmental regulations requiring dairy operators to adopt more advanced methods to manage their operations. The requirements of Senate Bill (SB) 700, San Joaquin Valley Air Quality Management District (SJAQMD) air quality regulations and Central Valley Water Board (CVWB) waste discharge regulations are examples of such rules. Anaerobic digesters, composting systems and other more costly waste management approaches are replacing traditional land application of dairy manure as accepted manure management practices. Consequently, if the economic returns of digester systems can be improved, then their greater implementation can be encouraged, which in turn will result in overall reduced air and water quality impacts.
**Water Quality Compliance**

Until relatively recently, most dairies located within the Central Valley Water Board jurisdiction operated under a waiver of waste discharge requirements. In May 2007, the Central Valley Water Board adopted Order No. R5-2007-0035 (Waste Discharge Requirements General Order for Existing Milk Cow Dairies). The order serves as general waste discharge requirements for discharges of waste from existing milk cow dairies and requires dairies to submit a Report of Waste Discharge prior to construction of an anaerobic digester.

The additional water quality requirements in the order have added considerable costs and restrictions. Farmers are now required to manage their applications of nutrients to their farmlands and otherwise protect their groundwater resources. The key water quality concerns for dairy digester systems are the potential for adverse groundwater impacts from dairy waste or digestate stored within farm lagoon systems and the added salt and nitrates from the importation of co-digester feedstock. The CVWB estimates that a typical 1,000 herd dairy produces approximately 3,600 tons (dry weight) of manure per year containing 180 tons of nitrogen and 235 tons of inorganic salts (CVWB, 2007).

Unless, landowners can prove that their farm’s specific site conditions will not result in water quality impacts, the primary compliance approach will be construction of more expensive Tier 1 lagoon systems. Currently, the CVWB is in the process of completing a comprehensive salinity management program with the State Water Board to address salinity problems within the Central Valley. However, until the new plan and program is completed, there are no general salt standards. Consequently review of dairy farm waste discharge compliance plans are performed on a case by case basis and the salt impacts of co-digester digestate are poorly understood, making it more difficult and costly for dairy farmers to comply with the water quality requirements.

Depending on the specific soil and groundwater conditions, some farms are required to install doubled lined lagoons (e.g., Tier 1) and/or reduce their application rates of liquid digestate or solid manure to comply with the state regulations. Salt accumulation issues within the Central Valley are likely to persist and there are currently limited management options for reducing the potential water quality impacts associated with accumulated salts.

Current regulatory differences between dairy and non-dairy farms also limit the ability for dairy farmers to export their manure or digestate to neighboring farms. While exportation of solid manure and/or digestate to other farms is permitted with little water quality regulatory oversight, a similar transfer of digestate effluent requires the recipient farm to comply with the WDR manure management testing and verification procedures. Although the recipient farmer could beneficially use the effluent to meet its fertilizer needs, faced with the regulatory requirements many farmers will instead elect to purchase and apply chemical fertilizer. The resulting outcome adds new nitrates locally (i.e., from the chemical fertilizer use) and reduces the options for manure digester operators to manage their nitrate load. In particular, wet system digesters (e.g., covered lagoons) that can not use all their digestate on site will likely have to reduce the water content of their effluent if the dairy farmer needs to export some of the material to meet the water quality standards. In which case, for the farmer to make the off-site transfer it will face added costs, energy use and water losses. Such offsite liquid

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30 Central Valley Salinity Alternatives for Long-Term Sustainability (CV-SALTS)
digestate transfer issues could potentially be an even more significant regulatory issue for a community digester or co-digester operation (Martin, P., 2010).

**Air Quality**

The California Air Resources Board (CARB) is responsible for regulating air emissions within the state. CARB is the lead agency for implementing the AB32 Scoping Plan which is the action plan for California to reduce it greenhouse gas emission substantially by 2020 with additional reduction by 2050. California farms were generally exempted from air quality regulations until the enactment of SB700 in 2003, which required most dairy farmers and other large confined animal feeding operations (CAFO) to obtain air quality permits for their operations from their local air district. Although rules vary between air districts, dairies that require air permits are now generally treated like other industries.

The San Joaquin Valley Air Pollution Control District has implemented several rules that apply to dairy operations including Rule 4550 (Conservation Management Practices [CMO] Plans), and Rule 4570 (Confined Animal Facilities). In the SJVAPCD new and modified dairies are subject to the New Source Review Rule – District Rule 2201, which requires Best Available Control Technology (BACT), Public Notice, Health Risk Assessment (HRA) & Ambient Air Quality Analyses (AAQA). For the SJVAPCD to issues permits, the projects are also required to comply with the California Environmental Quality Act (CEQA).

While the dairies are adapting to the new rules, the New Source Review Rule BACT requirements for NOx and SOx emissions from electrical generation equipment are cited as a real economic challenge for the dairies. There are several approaches to electrical generation but the systems are expensive to operate and poorly suited for dairy biogas or biomethane use.

The following is detailed updated information from Ramon Norman at the SJVAPCD describing the current requirements related to strict NOx emission limits (Norman, 2010). "For projects proposing to generate power from biogas in the San Joaquin Valley, the main pollutants that the District is concerned about are NOx and SOx. This is because these pollutants are precursors to ozone (NOx) and particulate matter (NOx and SOx). The San Joaquin Valley Air basin will soon be classified as extreme non-attainment for the Federal 1-hour ozone standard (and the now revoked Federal 8-hour ozone) standard - the worst classification. The San Joaquin Valley Air basin is also classified as non-attainment for the Federal PM2.5 standard. Because of the air quality problems in the San Joaquin Valley and reductions in NOx are critical to the District’s attainment strategy, the District is now requiring more stringent emission controls (such as catalysts) for biogas-fired engines and evaluating alternative equipment (fuel cells, microturbines, etc.) to further reduce NOx emissions down to 0.15 g/bhp-hr (around 9-11 ppmvd @ 15% O2) or less as BACT for these operations. This BACT level has been in place for fossil fuel-fired engines in the District for a number of years but the District is just beginning to apply this BACT level to biogas-fired engines. To meet the District BACT for NOx from these installations, controls (catalysts) would need to be added to an engine or an alternate technology, such as microturbines or fuel cells, would need to be used. Because the San Joaquin Valley is classified as non-attainment for the Federal PM2.5 standard and SOx is an important precursor for PM2.5, emissions of SOx must also be
Key Factors Determining Economic Feasibility

minimized. To meet the District BACT for SOx from these installations, scrubbing of the gas to remove H2S (down to 50 ppmv) prior to combustion will also be required. Because the San Joaquin Valley Air District is classified as attainment for the CO Ambient Air Quality Standard, BACT is usually not triggered for CO and engines would only be required to meet the 2,000 ppmvd CO limit from District Rule 4702.

At a minimum, any flares proposed for a digester system would need to satisfy the "Achieved in Practice" Category in the District's BACT Guidelines, which currently require a low-NOx flare with NOx emissions ≤ 0.06 lb/MMBtu. Any flares proposed for a digester would also need to satisfy the requirements of District Rule 4311, which requires enclosed flares to meet certain NOx and VOC emission limits and to be source-tested annually. Open flares (air-assisted, steam-assisted, or non-assisted) with flare gas pressure is less than 5 psig must be operated in such a manner that meets the control device requirements of 40 CFR 60.18. Emergency flares, which are exempt from the previous previsions, are required to maintain records of the duration of flaring events, the amount of gas burned, and the nature of the emergency. The requirements of District Rule 4311 can be found at the following link:


Any boilers or process heaters proposed for a digester system and rated 5.0 MMBtu/hr or greater would need to satisfy the requirements of District Rule 4320, which requires biogas-fired units to meet a NOx emission limit of 12 ppmv @ 3% O2 and also requires periodic source testing and emission monitoring. The requirements of District Rule 4320 can be found at the following link: http://www.valleyair.org/rules/currenrules/r4320.pdf.”

Mr. Norman also provided a list of suppliers of equipment that may be able to satisfy the District’s BACT requirement for NOx from power generating equipment that combusts biogas (Norman, 2010).

Inter-Agency Co-operation and Co-ordination

Fundamentally, there is a major challenge for finding a mechanism and forum for facilitating inter-agency co-operation and co-ordination. From a comprehensive cross resource perspective, manure digesters are generally recognized to offer significant net environmental benefits. However, since these benefits extend across several resource areas (i.e., air, water and energy use) and are not fully recognized by market mechanisms (e.g., odor and greenhouse gas reductions) balancing impact tradeoffs remains difficult. Currently methane emissions from dairy operations are not regulated.

As a result, while the negative air quality impacts of the N0x emissions are recognized, the corresponding (albeit different and less localized) air quality benefits of the methane destruction are not. Furthermore, there is not an easy mechanism for valuing the societal tradeoff of the beneficial energy capture (i.e., the produced electricity) from a resource that otherwise would have its entire energy resource value lost.

The complicated regulatory environment facing dairy operators is widely considered to be a major obstacle to future anaerobic digester development within the Central Valley. Several industry participants and analyses recommend that continued CEC and CPUC support to address technical and commercial risks is important for future development of manure digester systems in the Central Valley (Dusault, 2010). Improvement to the permitting process for complex projects with cross
resource impacts such as anaerobic digesters is generally recognized as important and necessary for encouraging future development of manure digesters. A centralized and stream-lined permit process that reduces the regulatory burden would greatly facilitate future dairy digester development.

**Utility Cooperation**

There is currently some mismatch between utilities interests and needs for digester development. Although there are some regulatory restrictions to utilities, there are many potential opportunities for a supportive utility role to bridge the existing market gaps and barriers to digester development. Support by utilities in this early stage of market development could have a significant positive role. Potential for utility participation in future projects is particularly important for the biomethane conditioning projects. SoCalGas is investigating the feasibility of potential cooperation and involvement in future biomethane production projects for pipeline injection with Sempra Energy (Goodman, 2010).

Several experts suggested that the market for future biogas would be improved if utilities such as PG&E were willing to invest, operate and maintain the necessary upgrading facilities required for pipeline injection. While such an approach would reduce the technical and investment burden on third party or dairy digester owners, the significant production costs for pipeline injection would remain high as only minimal savings would be potentially gained by reducing the utility need for verification of the non-utility injected biomethane quality.31 In addition, the location constraints of biogas acquisition in relative proximity to the utility transmission system would also remain.

Under the current market and regulatory conditions, there is little incentive for PG&E or other utilities to assume the additional costs, risks and responsibilities. Indeed, it may be expected that CPUC approval would be necessary for PG&E to undertake any such biogas development projects and pass on the costs to ratepayers.

**Emerging Technologies and Market**

As discussed above, the economic viability of future digester development appears currently to be primarily constrained by the comparatively low commodity prices for natural gas and electricity coupled by the relatively high costs of production. The complicated and cross resource impacts associated with dairy digester systems result in costly compliance requirements. Unless major breakthrough technological improvements are achieved, it is considered likely that manure digester production will remain economically unfeasible without government support for the foreseeable future. Furthermore, future improvements in feasibility would be expected to be minimal and incremental as long as natural gas and electrical prices remain relatively stable in real terms.

There is considerable hope within the renewable resource industry that fuel cells, “micro-scrubbers,” or other new technological improvements may be possible that could reduce unit production costs for biogas and/or biomethane production or enable affordable on-site electrical production that complies with air quality requirements.

31 It is likely that the utility would nonetheless need to evaluate biogas quality
Similarly, the economic feasibility for biogas production is presently reduced by the currently limited market for CBM and LBM as a transportation biofuel. Major growth in commercial and/or consumer natural gas vehicles (and the necessary related fueling infrastructure) would likely represent a new market and demand for CBM and/or LBM. In which case, dairy manure production of CBM and/or LBM might be able to take advantage of some comparative advantage of local production (especially over LBM which currently is mostly imported into California at some cost either by road or rail). However, until these biofuel markets develop or other major technical advances actually occur, the economic feasibility of dairy manure digesters can be expected to remain difficult without adequate governmental and/or regulatory assistance.

**Analysis Caveats**

The previous economic assessment is based on research and interviews during a highly dynamic period for the digester and other renewable energy industries. As outlined above, there are many unknown variables facing the industry – both technological and regulatory. Consequently, quantitative analysis of the industry economics is particularly challenging and, if imbedded assumptions or factors are not recognized, any finding can be misleading or highly prone to misinterpretation.

Furthermore, most digester analyses are very site and technology-specific. In addition, most operating digester projects have been pilot or demonstration projects that have received considerable government assistance. As a result, there is extensive complexity associated with any efforts to normalize the design, costs and performance of digesters operating under very different circumstances.

Consequently, we have used a predominantly qualitative approach since the primary purpose for this economic assessment has been to provide a framework by which the key economic drivers can be distinguished from the numerous variables and other factors that have a more indirect and lesser contribution to dairy digester feasibility.

**References**


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Acronyms

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<td>Assemble Bill</td>
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<td>ACEEE</td>
<td>American Council for an Energy Efficient Economy</td>
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<td>BACT</td>
<td>Best Available Control Technology</td>
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<td>PIER</td>
<td>Public Interest Energy Research Program</td>
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<td>PPA</td>
<td>Power Purchase Agreement</td>
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Glossary

Aerobic Bacteria: Bacteria that require free elemental oxygen to sustain life.

Aerobic: Requiring, or not destroyed by, the presence of free elemental oxygen.

AgSTAR: A voluntary federal program that encourages the use of effective technologies to capture methane gas, generated from the decomposition of animal manure, for use as an energy resource.

Anaerobic: Requiring, or not destroyed by, the absence of air or free oxygen.

Anaerobic Bacteria: Bacteria that only grow in the absence of free elemental oxygen.

Anaerobic Lagoon: A treatment or stabilization process that involves retention under anaerobic conditions.

Anaerobic: A tank or other vessel for the decomposition of organic matter in the absence of elemental oxygen.

Anaerobic Digestion: The degradation of organic matter including manure brought about through the action of microorganisms in the absence of elemental oxygen.
| **Best Management Practice (BMP)** | A practice or combination of practices found to be the most effective, practicable (including economic and institutional considerations) means of preventing or reducing the amount of pollution generated by nonpoint sources to a level compatible with water quality goals. |
| **Biogas** | Gas resulting from the decomposition of organic matter under anaerobic conditions. The principal constituents are methane and carbon dioxide. |
| **Biomass** | Plant materials and animal wastes used especially as a source of fuel. |
| **British Thermal Unit (BTU)** | The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. One cubic foot of biogas typically contains about 600 to 800 BTUs of heat energy. By comparison, one cubic foot of natural gas contains about 1,000 BTUs. |
| **Carbon Offset (Carbon Credit)** | A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be "additional" i.e. the offset provider must prove that the project would not have happened without its financial investment, and that the project goes beyond "business as usual" activity. |
| **Complete Mix Digester** | A controlled temperature, constant volume, mechanically mixed vessel designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery. |
| **Composting** | The biological decomposition and stabilization of organic matter under conditions which allow the development of elevated temperatures as the result of biologically produced heat. When complete, the final product is sufficiently stable for storage and application to land without adverse environmental effects. |
| **Covered Lagoon Digester** | An anaerobic lagoon fitted with an impermeable, gas- and air-tight cover designed to capture biogas resulting from the decomposition of manure. |
| **Demand charge** | The peak kW demand during any quarter hour interval multiplied by the demand charge rate. |
| **Digestate** | The sludge or spent slurry discharged from a digester. In this report digestate generally refers to the dewatered solids portion of the spent slurry, rather than the liquid digestate, which is referred to as the effluent. |
| **Digester** | A concrete vessel used for the biological, physical, or chemical breakdown of livestock and poultry manure. |
| **Discount rate** | The interest rate used to convert future payments into present values. |
| **Down payment** | The initial amount paid at the time of purchase or construction expressed as a percent of the total initial cost. |
| **Drystack** | Solid or dry manure that is scraped from a barn, feedlane, drylot or other similar surface and stored in a pile until it can be utilized. |
| **Effluent** | The discharge from an anaerobic digester or other manure stabilization process. |
| **Energy Charge** | The energy charge rate times the total kWh of electricity used. |
| **Fats** | Any of numerous compounds of carbon, hydrogen, and oxygen that are glycerides of fatty acids, the chief constituents of plant and animal fat, and a major class of energy-rich food. "Fats are a principal source of energy in animal feeds and are excreted if not utilized."

**Fixed Film Digester**

An anaerobic digester in which the microorganisms responsible for waste stabilization and biogas production are attached to some inert medium.

**Flushing System**

A manure collection system that collects and transports manure using water.

**Greenhouse Gas**

An atmospheric gas, which is transparent to incoming solar radiation but absorbs the infrared radiation emitted by the Earth's surface. The principal greenhouse gases are carbon dioxide, methane, and CFCs.

**Hydraulic Retention Time (HRT)**

The average length of time any particle of manure remains in a manure treatment or storage structure. The HRT is an important design parameter for treatment lagoons, covered lagoon digesters, complete mix digesters, and plug flow digesters.

**Inflation Rate**

The annual rate of increase in costs or sales prices in percent.

**Influent**

The flow into an anaerobic digester or other manure stabilization process.
Key Factors Determining Economic Feasibility

Internal Rate of Return  The discount rate that makes the NPV of an income stream equal to zero.

Kilowatt (kW)  One thousand watts (1.341 horsepower).

Kilowatt Hour (kWh)  A unit of work or energy equal to that expended by one kilowatt in one hour or to 3.6 million joules. A unit of work or energy equal to that expended by one kilowatt in one hour (1.341 horsepower-hours).

Lagoon  Any large holding or detention pond, usually with earthen dikes, used to contain wastewater while sedimentation and biological treatment or stabilization occur.

Land Application  Application of manure to land for reuse of the nutrients and organic matter for their fertilizer value.

Liquid Manure  Manure having a total solids content of no more than five percent.

Loading Rate  A measure of the rate of volatile solids (VS) entry into a manure management facility with methane recovery. Loading rate is often expressed as pounds of VS/1000 cubic feet.

Loan Rate  The percent of the total loan amount paid per year.

Manure  The fecal and urinary excretions of livestock and poultry.

Mesophilic  Operationally between 80°F and 100°F (27°C and 38°C).

Methane  A colorless, odorless, flammable gaseous hydrocarbon that is a product of the decomposition of organic matter. Methane is a major greenhouse gas. Methane is also the principal component of natural gas.

Minimum Treatment Volume  The minimum volume necessary for the design HRT or loading rate.

Mix Tank  A control point where manure is collected and added to water or dry manure to achieve the required solids content for a complete mix or plug flow digester.

Natural Gas  A combustible mixture of methane and other hydrocarbons used chiefly as a fuel.

Net Present Value (NPV)  The present value of all cash inflows and outflows of a project at a given discount rate over the life of the project.

NPV Payback: The number of years it takes to pay back the capital cost of a project calculated with discounted future revenues and costs. Profitable projects will have an NPV Payback value less than or equal to the lifetime of the project.

Nutrients  A substance required for plant or animal growth. The primary nutrients required by plants are nitrogen, phosphorus, and potassium. The primary nutrients required by animals are carbohydrates, fats, and proteins.

Operating Volume  The volume of the lagoon needed to hold and treat the manure influent and the rain-evaporation volume.

Payback Years  The number of years it takes to pay back the capital cost of a project.

Plug Flow Digester  A constant volume, flow-through, controlled temperature biological treatment unit designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.

Point Source Pollution  Pollution entering a water body from a discrete conveyance such as a pipe or ditch.

Process Water  Water used in the normal operation of a livestock farm. Process water includes all sources of water that may need to be managed in the farm’s manure management system.

Proteins  Any of numerous naturally occurring extremely complex combinations of amino acids containing the elements carbon, hydrogen, nitrogen, and oxygen. Proteins are in animal feeds are utilized for growth, reproduction, and lactation, and are excreted if not utilized.

Renewable Energy Credits (RECs)  Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.

Scrape System  Collection method that uses a mechanical or other device to regularly remove manure from barns, confine buildings, drylots, or other similar areas where manure is deposited.
Simple Payback: The number of years it takes to pay back the capital cost of a project calculated without discounting future revenues or costs.

Slurry (Semi-solid) Manure: Manure having a total solids content between five and ten percent.

Solids Manure: Manure having a total solids content exceeding 10 percent.

Storage Pond: An earthen basin designed to store manure and wastewater until it can be utilized. Storage ponds are not designed to treat manure.

Storage Tank: A concrete or metal tank designed to store manure and wastewater until it can be utilized. Storage tanks are not designed to treat manure.

Straight-Line Depreciation: Depreciation per year equals the total facility cost divided by the years of depreciation (usually the facility lifetime).

Supplemental Heat: Additional heat added to complete mix and plug flow digester to maintain a constant operating temperature at which maximum biological treatment may occur.

Technical Advisory Group (TAG): A working group of individuals representing several California State Agencies and companies knowledgeable and interested in the Environmental Impact Report (EIR) being prepared for Dairy Manure Digester and Co-digester Facilities. The group is scheduled for four meetings and will review various background documents that will help to support the preparation of the EIR.

Thermophilic: Operationally between 110°F and 140°F (43°C and 60°C).

Total Solids: The sum of dissolved and suspended solids usually expressed as a concentration or percentage on a wet basis.

Utility Interconnection: The method of utilizing electricity produced from manure management facilities. Options include either (1) on farm first use then sale to utility or (2) sale to the utility then direct purchase.

Volatile Solids: The fraction of total solids that is comprised primarily of organic matter.

Volatilization: The loss of a dissolved gas, such as ammonia, from solution.

Volumetric Loading Rate: The rate of addition per unit of system volume per unit time. Usually expressed as pounds of volatile solids per 1,000 cubic feet per day for biogas production systems.
From: Nik Carlson
Sent: Fri 7/23/2010 4:11 PM
To: Paul Miller
Cc: 
Subject: FW: Biogas report
Attachments: dairy-digester-feasibility-2010-04_ED.pdf (506KB)

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From: Ikle, Judith [mailto:judith.ikle@cpuc.ca.gov]
Sent: Friday, April 30, 2010 5:59 PM
To: Nik Carlson
Cc: Lee, Cheryl; Cadenasso, Eugene
Subject: RE: Biogas report

Just wanted to make sure you received this.

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From: Lee, Cheryl
To: Ikle, Judith
Cc: Cadenasso, Eugene
Sent: Fri Apr 30 16:47:56 2010
Subject: Fw: Biogas report

Judith,

Here is a copy of ESA's draft report w/comments.

-Cheryl
KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Prepared for the
California Regional Water Quality Control Board, Central Valley Region

April 2010
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209481
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KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Executive Summary

Extensive research and review was conducted on published industry analyses on anaerobic digestion and the use of dairy manure for bioenergy within California and elsewhere within the United States. Numerous factors are identified as key contributors influencing the future economic viability of the potential development of dairy manure digesters and co-digesters within the Central Valley. The factors determined to be important economic drivers (both positive and negative) are summarized below:

- **Energy Prices.** Most fundamentally, current and projected future commodity prices of natural gas and electricity are critical revenue constraints for dairy digesters. Natural gas is a readily available substitute for dairy digester produced biogas and biomethane. Consequently, most potential customers will be unlikely to buy biogas or biomethane at prices much above their commodity price for natural gas. Similarly, the value of biogas generated electricity will be limited by the prices of utility supplied power alternatives. Currently, long term natural gas and electricity prices are not forecast to increase (adjusted for inflation) due to recent discoveries of new domestic shale gas reserves. Consequently, biogas can not expect substantially improved feasibility from future commodity price escalation.

- **Air Quality Regulation of On-site Electrical Generation.** On-site generation of electricity represents a potential direct, “lower tech” and inexpensive beneficial use option for biogas. However, air quality restrictions within the Central Valley may preclude this use. If cost effective compliance technologies or mitigation can be developed, digester systems could be greatly enhanced – especially if adequate feed-in tariffs or other utility support increases the revenue potential for small scale distributed energy production.

- **Public Sector Support.** Federal and state grant funding, low interest loans and other public sector support (e.g., tax incentives and pilot programs) have played a vital role in past digester development. Both the amount and form of future public sector support can have a strong positive role in fostering manure digester implementation within the Central Valley. Future government support is expected to remain essential for continued development of manure digester systems.

- **Access to Capital and Third Party Developers.** The current financial difficulties facing most dairy farmers and the generally tight credit market will ensure that funding for digester developments will be scarce and costly for the foreseeable future. While increased participation by third party developers may provide some technical and financial assistance, private capital...
will be relatively costly. The potential “capital crunch” constraints will be especially acute for those biomethane production projects that require major construction, involve new technical applications and/or supply biomethane to less established and developing non-utility markets.

- **Biogas Upgrading for Biomethane Production.** Biogas scrubbing and conditioning for biomethane production is currently costly and can only be cost effectively performed at production levels significantly greater than most individual dairy operations can support. Combined with biogas upgrade system costs, system design and location requirements represent key factors limiting the feasibility of digester biogas sales for the foreseeable future.

- **Role of Utilities.** Local utilities represent a key potential customer for surplus energy production from dairy digesters. Local utilities are the predominant energy producers and wholesalers in the market and therefore can most effectively and efficiently manage the sale, distribution and use of digester produced energy. Currently, utilities are understandably wary of such distributed energy projects since they represent emerging competition. In general, the administration of small scale production (from dairy digesters) provides limited financial return for utilities. Utilities also face regulatory restrictions that limit both their involvement and, most importantly, the prices that they can pay for dairy digester energy. However, innovative and constructive partnerships between digesters and utilities offer a key potential mechanism for greater and more cost-effective development of biogas as a renewable resource.

- **Technological Change.** Although many of the core digester and biomethane technologies are fairly well established, future commercialization of dairy manure digester systems may be expected to result in some cost effectiveness improvements. However, currently most foreseeable improvements appear to be incremental rather than fundamental. Consequently, most analysts suggest that per unit production costs for biomethane and related electrical generation will remain higher than commodity energy prices and hence public support for production will remain necessary. Key technology breakthroughs that could dramatically improve future dairy digester profitability include cost-effective on-site electrical generation with biogas (e.g., very low emission micro-turbines or fuel cells) or inexpensive and/or farm sized biogas upgrading systems.

- **Proximity to Feedstocks and Energy Markets.** The location of potential dairy digester and co-digester systems can be critical to the facility’s ability to obtain sufficient manure (and possibility feedstocks for co-digesters) and/or supply its biogas and other facility products to potential buyers at an attractive price.

- **Permitting.** Facility development design and permit costs to comply with state and local regulations can represent major delays, risks and financial expenses that may discourage potential digester development.

Many other factors will also contribute to the profitability of dairy digester systems. Generally, the effects of the other factors are relatively minor compared to the economic drivers identified above. For example, many analyses have investigated the potential for revenues gains from digester byproducts (e.g., digestate sales), tipping fees (for co-digester), or the environmental attributes of anaerobic digesters (renewable energy credits and carbon offsets) as important feasibility factors. However, the magnitude of these often speculative revenues will remain secondary to the value of the digester’s primary product, which is biogas.
Introduction

The technological feasibility of biogas production from manure digesters and co-digesters is well established. Generally, digester produced biogas has been used for on-site generation of electricity and/or heating to meet the farm needs. Farm digester systems typically can produce three or four times the amount of energy that their farm’s need. This surplus biogas production represents a significant renewable energy resource with considerable potential economic value and environmental benefits.

However, to understand and evaluate the economic and environmental trade-offs associated with future manure digester and co-digester systems in the Central Valley of California, the key factors determining the economic feasibility need to be determined. Three basic types of economic factors can be identified: revenue factors, cost factors and implementation/development issues.

The balance and interrelationships of these factors under the specific project circumstances will determine the project’s overall feasibility. Most simply stated, if the average revenues (i.e., on a per unit basis) are greater than the digester’s average cost of production, then the project will have a positive benefit-cost ratio and will, in a basic sense, be economically feasible. However, to fully assess the project’s feasibility, implementation factors should also be considered to determine the likelihood that successful future development can occur.

Revenue and costs naturally face tradeoffs in the project’s feasibility as increased costs are usually necessary to generate higher revenues. The key for improving a project’s feasibility occurs when the marginal revenues are greater than the marginal cost required for the revenue growth.

Each factor will have both technical and financial components determining the magnitude and nature of its effect on the system’s feasibility. Generally, economies of scale associated with greater production efficiencies will result in a lower production cost per unit.\(^1\) Similarly, at a fixed rate of production, higher sale revenues (or reduced production costs) will increase the revenues per unit. In both cases, the system’s economic feasibility will be improved.

The following analysis provides a brief description of the key factors affecting the economic feasibility of digester systems. The nature and extent of each factor’s contribution or role to the economic feasibility is also identified and evaluated. The central purpose of the analysis is to identify those economic or technological “drivers” that play a major role in determining the viability of digester system development. Expected future trends that might alter the system’s overall economic feasibility are discussed.

The analysis generally discusses manure digesters and unless explicitly noted otherwise, should be read as also applicable to and inclusive of co-digester systems. In addition the report maintains an important distinction between biogas and biomethane. Biogas is generally synonymous with raw biogas (i.e., the unrefined biogas produced by anaerobic digesters that has a methane content of 50 to 65 percent). Biomethane refers to refined biogas with higher methane content, typically 95 percent or more.

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\(^1\) Except in cases where equipment of facility requirements or cost / revenue thresholds may result in a “step-function” cost.
Finally, it should be noted that this analysis primarily addresses “economic” feasibility issues and as such considers the general costs and benefits of manure digesters. Strictly speaking, “financial” feasibility analysis typically refers to a more specific and comprehensive determination of the revenues and expenditures for a well-defined and site specified project. As such, a financial feasibility analysis would typically provide a more detailed description and estimates of project costs and revenues, consider its business cash-flow and include greater characterization of applicable market conditions and other considerations – primarily from the perspective of the potential owner/investor. Nonetheless, financial and economic factors are often used interchangeably. Unless specified otherwise, references to financial issues will refer to a more general economic assessment of cost and revenue issues.

The economic feasibility for specific systems will depend not only on general feasibility factors but may also depend upon site- or system-specific considerations. Nonetheless, important general observations can be identified and assessed.

**Revenue Factors**

The revenues generated by a future digester are central for its economic viability. Typically, it is more difficult to estimate future revenues than it is to estimate future costs which are easier to specify. This is particularly true in the case of a new or emerging market (e.g., such as biomethane) where the potential customers and future product applications are difficult to identify and fully evaluate.

The following section provides a brief overview and assessment of the various factors that will influence the potential revenue performance of future anaerobic digester development in the Central Valley of California. When possible, the relative magnitude and any significant future revenue variables are also reported so that those factors that are current and future revenue “drivers” can be identified and their inter-relationships with cost and implementation better understood.

**Biogas Productivity**

The efficiency and effectiveness of biogas / biomethane production of manure digesters and other related production processes is a central factor in determining economic feasibility. All else being equal, greater biogas production will increase the system’s revenue potential and hence cost-effectiveness.

Currently, most dairy digester produced biogas is used on-site for energy generation. Electrical production is generally the primary use of the produced biogas although heat is frequently also produced for use in the anaerobic digester either as part of a combined heat and power system (CHP)\(^2\) or separate dedicated boiler systems. Consequently many of the feasibility studies for manure digesters report their productivity and costs in terms of the system’s electricity production.

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\(^2\) The thermal energy recovered in a CHP system can be used for heating or cooling farm facilities. Since CHP captures the heat that would otherwise be lost in traditional electrical generation, the efficiency of an integrated system is much greater (up to 85%) than the separate systems combined efficiency (45%) (ACEEE, 2010).
Overall System-wide Estimates

There is a wide variance in the methane and electrical production rates estimated for manure power systems. The potential biogas production will not only depend on the anaerobic digestion process used but also on both the volume of biodegradable organic materials in the collected manure and the length and type of manure collection and storage used. Similarly, the amount of electricity that can be produced by the digester system will also depend on the electrical generation system used.

The California Energy Commission (CEC) conservatively estimates an average 36 cu.ft. of methane per cow per day (with an energy content of 36,000 Btu/day) which can generate 0.107 kWh of electricity. The EPA estimates that manure digesters can typically produce 38.5 cu.ft. of methane per cow per day (EPA, 2004).

Actual daily electrical generation performance at Hilarides Dairy was substantially less at 0.055 kWh per cow (though partly due to substantial biogas flaring during the evaluation period) (WURD, 2006). Craven Farms reported achieving daily energy values of 34,500 Btu/cow with a 0.096 kWh per cow electricity generation rate that is comparable to CEC estimates. Other studies suggest 0.14 kWh per cow (Electrigaz, 2008), and 0.1 kWh per cow (Black & Veatch, 2007) as reasonable daily electrical productivity projections. Other analysts have more optimistic estimates of the per cow energy values. PG&E has estimated that each cow may generate 1,640 kWh annually (equivalent to 0.187 kWh per cow).

Within these biogas production parameters, it is generally agreed that adequate biogas capacity can be attained by larger dairies for development of dairy digesters to be technically feasible, and to be potentially economically viable with sufficient revenue assistance.

Specific Digester Systems

Manure Digesters

Three primary anaerobic digester system approaches are commonly used to treat dairy manure. The system most suited for a specific dairy operation will generally depend on its manure management system. As of October 2009, 21 major anaerobic digester systems had been constructed and are currently operating within California. The digester systems vary from relatively small dairy farm facilities processing the manure wastes for approximately 200 head of cattle to very large dairies with up to 5,000 cattle.

- **Covered lagoon systems** are the most basic and traditionally the most inexpensive anaerobic digester systems to construct and operate. These systems require the manure to be highly diluted (typically with a 3% or less total solid content) roughly consistent with “flush” manure handling. Covered lagoon digesters generally are unheated (mesophilic) and are not well suited for co-digestion with other feedstock. The average retention times for processing the manure is 45 to 60 days. The biogas conversion rates for covered lagoon
Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-digester Facilities

systems are generally 35% to 45% (Burke, 2001). Covered lagoon systems are currently the most widely constructed and operated dairy digester systems in California.

- **Complete mix systems** consist of a tank constructed of either reinforced concrete or steel. The digester contents are periodically mixed and frequently heated to maintain an optimal temperature for methane production. As a result, complete mix systems are more expensive to construct and require applied energy to operate. These systems work best with slurry manure with a total solids content of 3% to 10%. As a result they can be used by managed flush manure management dairies or scrape manure dairies if water can be added to the collected manure. Complete mix systems are well suited for co-digestion and have a relatively short retention time of 15 to 20 days. Consequently they are also able to handle higher processing loads. Heated digestion (thermophilic) with a complete mix system can be expected to increase biogas conversion rates to 45% to 55% (Burke, 2001). Currently, there only a few complete mix digester systems are operating within California.

- **Plug Flow Digesters** consist of a long relatively narrow tank often built below ground. The digester requires semi-solid manure (i.e., with a total solid content between 11% and 13%) consistent with “scrape” manure management systems. Plug flow systems can be operated heated or unheated. The costs and biogas conversion rates for plug flow digesters are comparable to similar complete mix systems. Typical retention time for plug flow digesters are 20 to 30 days (Burke, 2001). Also, plug flow digesters are less well suited for co-digestion use. Currently, 6 plug flow digesters current operate or recently operated within California.

Until recently, the price performances of these three digester systems were roughly comparable. The higher biogas production from managed digesters systems (i.e., complete mix and plug flow) covered the additional construction costs. As a result, the costs per cow for these systems were approximately the same (Martin, 2010). However, as result of recent imposed manure management regulations for Central Valley dairy farms, depending on their land and groundwater conditions, many farmers are required to construct more expensive Tier 1 lagoon systems. In such cases, the added costs for double lining or reinforcing the lagoons represent a significant additional cost and will make complete mix and plug flow systems more attractive and cost-effective digester systems for biogas production.

Wider adoption and commercialization of digester systems may be expected to reduce system costs and improve performance – both from facility design improvements and better system management. However, the biogas productivity improvements will be relatively limited and incremental.

**Co-digesters**

The biogas productivity of dairy manure digesters can be greatly increased by the addition of other non-manure organic feedstocks. The proportional increase in biogas production will depend on the quality and suitability of the added feedstock. Food or agricultural wastes with higher oil or grease contents will generally release a greater amount of methane than other feedstocks with lower potential energy values. There is considerable variation amongst analyses in the amount of additional methane that co-digesters can produce. A conservative analysis for the CEC observed approximately a 35% improvement in methane production by co-digestion (CH2M Hill, 2007). Other commenters suggest that high energy feedstocks (e.g. fats, oils and greases or municipal
organic wastes) could result in a doubling or even tripling of biogas production by dairy digesters (Hintz, 2010). Such industry analysts projected that the potential for major gas productivity improvements (supplemented by tipping fee revenues with longer term contracts for handling the municipal green wastes) will make a substantial improvement in the economic feasibility of biogas production (Best, 2010).

Co-digestion is more management intensive and could add greater reporting and oversight requirements to comply with water quality and solid waste regulations. However, the additional equipment costs for enhanced production should be minor (presuming the feedstock handling, preparation and storage requirements are limited). Consequently, many analysts suggest that co-digestion can provide cost effective biogas production gains.

However, availability of suitable feedstock will be important for determining the practicality and cost effectiveness of co-digestion. Many analyses identify potential tipping fee revenues for the digester operator from the feedstock sources as an important additional revenues source. However, as discussed later under the discussion of by-product revenues, most potential agricultural wastes are only seasonally available and may be located too far from specific digesters to be cost-effectively transported. Feedstocks also may become a commodity so that co-digester operators will likely have to obtain a variety of different feedstocks.

**Centralized Digester**

Only a few studies have assessed the economic feasibility of centralized digesters within the United States. Feasibility studies for centralized digester systems in New York state, southern Wisconsin and Oregon concluded that the proposed systems were uneconomical (Bothi, 2005; Reindl, 2006; DeVore, 2006). Analysis for a centralized manure digester in Dane County, Wisconsin projected significant cost efficiencies compared to individual systems but still required major public and private sector support.

A few large centralized manure digesters have been constructed and operate in the United States. The Inland Empire Utilities Agency’s (IEUA) Chino Basin project in South California was the first centralized anaerobic digester to be developed in the United States and is the only centralized digester facility currently operating in California. The IEUA project came online in 2002 and processes 225 tons of manure per day from 6,250 dairy cows, plus food waste from local food industries. The manure is trucked to the facility from six farms located within 6 miles of the digester (Davis, 2009).

However, currently all of these centralized digesters are in effect demonstration projects having received major funding assistance and have faced significant operational difficulties. The Chino Basin facility itself received approximately $5 million of its $8.5 million construction cost from the USDA’s Natural Resource Conservation Service (NCRS) for watershed protection. The CEC provided approximately $2 million in funding with the remainder provided by the Inland Empire Utilities Agency (IEUA) that owns and operates the facility. The energy generated from the biogas powers the agency’s off-site groundwater desalinization plant and wastewater facilities.

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5 It is presumed that co-digestion will not substantially alter the value or use of the resulting digestate except for the negative aspects from potential net nitrate and salt increases associated with the feedstock importation to the dairy.
Large scale biomethane production requirements are a primary rationale for centralized digester systems. Although there are potential limited economies of scale for the centralized digester, manure transportation and handling costs can offset the economic savings if there are not sufficient suitable dairies willing to participate in close proximity to the proposed facility. Given the limited and geographical constraints on such facility’s economies of scale, the centralized digester systems represent a secondary factor for digesters’ economic feasibility. Currently, there are only limited future system enhancements foreseen that would improve their cost-effectiveness.

**Electrical Generation**

Electrical generation is currently the primary use of digester biogas within California. Biogas (and biomethane) can be used to generate electricity using a variety of technologies including reciprocating engines (e.g., such as internal combustion), microturbines, gas turbine and fuel cells. Electrical generation with digester gas represents a promising distributed generation (DG) technology offering not only the environmental benefits of offsetting fossil fuel use but also has the additional benefit of destroying methane which otherwise would have major greenhouse gas impacts.

Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in the determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. This emission standard has been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards.

Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, currently properly operated “clean burn” IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations (Joblin, 2010). While additional selective catalytic reduction can in some cases be used to further reduce emissions, the necessary secondary emission controls are expensive and difficult to operate on lower energy fuels such as unrefined biogas. Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 - 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the SCS-Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010).

Microturbines are a newer technology that is becoming increasingly available. While potentially well suited for low emission electrical generation using biomethane, microturbines generally do not operate well under hot climate conditions (e.g., such as during summer months within the Central Valley). Recent implementation efforts at dairy digesters have been mostly unsuccessful as

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6 Only Vintage Dairy facility near Fresno uses the majority of its biogas production for biomethane production and injection into the utility grid.

7 Distributed generation also potentially offers additional system benefits of reduced transmission line infrastructure requirements and possibly reduced peak power system capacity requirements.

8 Current microturbines cannot be used with biogas due to the effects of hydrogen sulfide impurities.
reliability issues could not be solved for on-farm uses (Dusault, 2010). Analysts also suggest that at comparable implementation scales, the thermal conversion efficiency of microturbines will typically be 5% less than internal combustion (IC) engines.

TABLE 1
COMPARISON OF ELECTRICAL GENERATION TECHNOLOGIES FOR BIOMETHANE

<table>
<thead>
<tr>
<th>Factors</th>
<th>Microturbines</th>
<th>Combustion Turbines</th>
<th>Reciprocating Engines</th>
<th>Fuel Cell</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost ($/kW)</td>
<td>$300 - $1,000 / kW</td>
<td>$300 - $1,000 / kW</td>
<td>$300 - $900 / kW</td>
<td>$5,500 - $12,000 / kW</td>
</tr>
<tr>
<td>Commercially Available</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Only Phosphoric Acid Fuels Cells Available</td>
</tr>
<tr>
<td>Size Range</td>
<td>30-500 kW</td>
<td>500 kW – 25 MW</td>
<td>5 kW – 7 MW</td>
<td>1 kW – 10 MW</td>
</tr>
<tr>
<td>Efficiency</td>
<td>20 – 30%</td>
<td>20 – 45% (at scale)</td>
<td>25 – 45%</td>
<td>30 – 60%</td>
</tr>
<tr>
<td>Emissions</td>
<td>Low (&lt;9 – 50 ppm) NOx</td>
<td>Very Low when controls applied</td>
<td>Emission Controls Necessary for NOx CO – 50 ppm min.</td>
<td>Nearly zero</td>
</tr>
<tr>
<td>CHP Possible</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Commercial Status</td>
<td>Small Volume Production</td>
<td>Widely Available</td>
<td>Widely Available</td>
<td>Only Phosphoric Acid Fuels Cells Available</td>
</tr>
</tbody>
</table>

All dollar amounts in 2007 dollars.
SOURCE: California Energy Commission; ESA.

Combustion turbine engines are a mature technology but scale issues for their implementation preclude their use with dairy digesters except for the relative large or centralized community systems. At the lowest end of the scale, at least 5,000 dairy cows would likely be necessary to generate sufficient biogas production. The conversion efficiencies for combustion turbines are also expected to be reduced at the scales likely to be applicable for any on-site or community systems.

Fuel cell technology is currently at an early stage of development and consequently the costs for fuel cells are many times greater than for comparably sized micro-turbine, turbine or IC engines. Even though the efficiency of fuel cells are considerably better than the other technologies, given this very large production cost differential, until major technological improvements and/or large scale commercialization is achieved, fuel cells will remain dramatically less cost-effective for implementation.

EPA estimates that that the maximum thermal conversion efficiency of biogas to electricity by a standard reciprocating engine (internal combustion) is 28.5%.\(^9\) However, due to the difficulty in sizing engine-generator sets for optimal efficiency as well as a likely on-line operating rate of 90%, electrical output for biogas is estimated to be 66.6kWh / 1,000 cu.ft. of methane. Other analysts recommend that realistically, the thermal efficiency conversion to electricity is between 18% and 25%.

Electrical production with biogas will remain an important potential alternative use for digester systems. Consequently, the electrical generation productivity will have a direct revenue effect by determine the amount of energy that can be sold or used from the system. But, as discussed below,

\(^9\) The reduced efficiency rates for biogas electrical generation compared to natural gas reflect the biogas’s lower methane and higher impurities content.
other factors such as pricing structures with local utilities will have a greater influence on the system’s overall economic feasibility than its electrical generation performance. However, it is possible that major technological advances could provide major improvement in the cost-effectiveness and/or environmental performance of future biogas electrical generation systems.

**Commodity Prices of Energy**

**Natural Gas**

Generally speaking, biomethane is a more valuable energy commodity to utilities than biogas generated electricity since the biomethane can be more readily stored for later use. Consequently, it is easier for utilities to use the biomethane as an energy resource during periods of higher energy demand (i.e., when its value as an energy resource will be higher).

In a fundamental way, the commodity price of natural gas constrains the economic value and sale price for digester system produced biogas and biomethane. Natural gas is a substitute energy alternative for on-site biogas use, off-site commercial sale or upgrading to biomethane. If the renewable and environmental attributes of the produced biomethane are considered separately (i.e., Renewable Energy Credits [RECs] and greenhouse gas [GHG] credits), then the core value of biomethane will be largely limited to the substitution cost for potential purchasers (e.g., such as industrial users or utility) to use natural gas to meet their energy needs.

In past years, the price of natural gas has fluctuated greatly. The price variability had been partly due to the major international oil price fluctuations and global economic instability. Current natural gas prices are approximately $5.40 /1,000 cu.ft.\(^\text{10}\) Extensive future supplies of domestic natural gas are currently believed to be available and ongoing technological improvements in natural gas recovery are expected to enable natural gas production to increase over the next 25 years. During that period, natural gas prices are expected to remain unchanged in real terms (USEIA, 2010).

While long term stable natural gas prices (in real terms) are good for the general economy, the absence of any significant future natural gas commodity price increase will undercut the future economic feasibility of biomethane production. If the sales prices for biomethane are restricted to current natural gas prices, any future production costs increases can be expected reduce the profitability of biogas production unless offsetting technological improvements are achieved.

Currently, biomethane pipeline injection is only permitted into PG&E’s transmission pipelines due to insufficient and inconsistent demand within its distribution network. Furthermore, to meet the utilities flow requirement, any biomethane injection to the transmission pipeline must occur near urban areas that have adequate and consistent natural gas demand.

An initial pilot project at the Vintage Dairy near Fresno is currently operating and processes manure from approximately 3,000 cows into biomethane. The dairy has successfully upgraded its biogas to meet PG&E’s gas quality requirements. Vintage Dairy is located along a natural gas transmission

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\(^\text{10}\) City Gate Price for November 2009 (U.S.E.I.A, 2010).
line and therefore in able to inject on-site. In PG&E’s experience, biogas injection projects more than 4 to 5 miles from a transmission pipeline are less economically viable (PG&E, 2009). Other studies and analysts have also concluded that proximity to interconnection locations are a major limiting constraint for the feasibility of biomethane pipeline injection (Goodman, 2010). Consequently, the existing natural gas transmission system infrastructure is considered a key feasibility constraint for future development of any dairy biomethane pipeline injection within the Central Valley.

Biomethane could potentially be piped to local industry or commercial customers with sufficient energy needs. Again however, due to the relatively high cost of construction for delivery pipelines, proximity to the biomethane production facility will be a key feasibility constraint. Furthermore there are likely to be only a limited number of industrial or commercial users with adequate power demand.11

Alternatively, biomethane can be compressed or liquefied for truck transportation and/or transportation fuel use. The biogas conditioning requirements for compression biomethane (CBM) or liquefied (LBM) are comparable to those required for pipeline quality biomethane although specific users or fuel use may accept higher carbon dioxide levels.12 As is discussed in the assessment of production costs, the purified biomethane must not only be compressed or liquefied, but on-site storage is also likely to be necessary until it can be truck transported to its end customers. Given their very similar chemical composition, the market prices for compressed CBM and LBM are expected to be highly comparable to compressed natural gas (CNG) and liquefied natural gas (LNG) prices.13

The commercial sales potential for CNG and LNG are currently relatively limited. However, CNG offers substantial fuel cost savings as prices are currently averaging approximately $2.25 per gallon gasoline equivalent compared to diesel’s current $2.70 per gallon gasoline equivalent (cngprices.com 2010; CEC, 2010). The current market is primarily focused on sales as a “clean” transportation fuel for vehicle fleets. While municipal or government agencies have been major initial adopters of CNG vehicles, private companies are also considered potential customers. Presently, the main operational limits to CNG powered vehicles use is their horsepower constraints which make them less well suited for trucking us over major gradients. The greatest market demand for CNG fuel is within California’s major urban areas where the negative air quality effects of diesel trucks are highest and the CNG supply infrastructure can be most cost effectively developed.

Although, there are existing and future sales opportunities for CBM and LBM, it remains an emerging market that is constrained by the higher cost of conversion or purchase of CNG/LNG powered-vehicles and the need for expansion of the fueling infrastructure. Consequently, the value of both CNG and LNG are expected to remain closely related to natural gas prices with a relatively limited potential for any price “premium” for biomethane.

11 Under some circumstance and pending local air quality issues, it may be viable for “raw” biogas to be used for industrial or commercial heating systems. In which cases, if the relatively costly biogas upgrading are avoided, it could be economically viable to pipe the biogas further distances to commercial customers.

12 Acceptance of higher carbon dioxide proportion will offer some production cost savings.

13 If the biomethane’s environmental attributes (e.g., renewable energy credits [RECs]) are valued separately. Given the nascent CBG and LBG markets it should be conservatively assumed that no major premium biogas price would be obtainable – especially given the relatively small production levels likely for the foreseeable future.
Electricity

Similar to natural gas, electricity prices have a central influence in determining the economic performance of digester systems. The “retail” electricity price that farmers currently pay to meet their on-farm needs determines a maximum economic value for their potential electric cost savings earned by self generation. The avoided cost for purchasing electricity at the utility’s retail price will offer direct economic benefit for dairies that can self generate electricity on-site to meet their electricity needs. Electrical generation for on-farm use and/or net metering plays a vital role in the economic performance of current operating dairy manure systems (PERI, 2009).

Net Metering

Retail electric rates in California are comparatively higher than elsewhere in the United States and consequently will increase the potential economic attractiveness of alternative energy sources. Currently, the typical base “retail” electricity price facing farmers within the PG&E service area is $0.12 kWh to $0.14 kWh. However, during peak periods electricity prices can increase to more than $0.25 kWh (PG&E, 2010).

In 1995, the California State Legislature passed SB 656 (Alquist), which required all electric utilities to buy back any electricity generated by a customer-owned solar and wind systems system. This buy-back program is known as “net metering” because the electricity purchases of the customer are netted against the electricity generated by the customer’s renewable system. The customer’s utility bill is calculated on the net quantity of electricity bought from the utility. However, the utilities were not required to purchase any surplus generated by the customer and it was only the subsequent Assembly Bills 2228 (passed in 2002) and 728 (passed in 2005) that required the utilities to offer net metering to dairy farms that generated electricity with biogas.

Past net metering regulations did not encourage digesters operating as electricity “exporters” since the program only allowed them to “bank” their energy production in the utility grid. As a result, biogas producers often chose to flare excess biogas rather than generate electricity for which they would receive no compensation from their local utility. In addition, dairy farmers do not receive the full retail price for their self generated electricity but still incur tariff charges for transmission and distribution, demand charges, public purpose funds. These additional costs can be considerable – averaging $0.055 / Kwh (in 2005 dollars) for a typical dairy (Krich, 2005).

However, recent passage of AB 920 has amended the net metering provisions to require utilities after January 2011 to compensate customers for any surplus electrical production. This improves the future revenue potential for dairy’s self-generating electricity.

Feed-In Tariffs

Following the passage in 2006 of Assembly Bill (AB) 1969 (and subsequent CPUC rulings), PG&E and other California utilities14 are now required to buy excess energy generated with renewable sources from qualified customers. Dairies that generate electricity can choose to sell their surplus

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14 Although several utilities serve farmers within the Central Valley, PG&E is predominant utility provide for the region and consequently the analysis primarily refers to PG&E in its discussion of utility issues.
electricity to their local utility under a Small Renewable Generator Power Purchase Agreement (PPA) provided they sell less than 1.5 MW of power (which at average of 0.107 kWhr / cow would be equivalent to surplus power production by 14,000 cows). This “feed-in tariff” program is in some ways a more sophisticated net metering program as the dairy’s usage and exports to the grid are both measured for quantity and by time of delivery. Under the feed-in tariff program, small renewable energy producers are able to obtain long-term contract for their energy production at a very low transaction cost which should assist in raising capital investment. This is a primary benefit offered by the feed-in tariff program to potential dairy digester developers.

Under the feed-in tariff program the purchase price for excess electricity is set by the CPUC according to the market price referent (MPR) determined as part of the State’s renewable portfolio standard proceedings. The MPR values offered under the feed-in tariff program are based on the comparable costs for electrical production at large scale utility power plants. As such, the MPR is unrelated to the actual cost of renewable energy production and therefore does not provide any subsidy to encourage specific renewable resources.15

The prices paid for the surplus power is also adjusted for its “time of delivery” which recognizes the higher value of power supplied during on-peak periods and its lower value during off-peak hours. Current MPR values are approximately $0.09/kWh and producers can enter into 10, 15 or 20 year contracts with the utility (PG&E, 2010).

The feed-in tariff programs provide an improved mechanism for dairy digester to sell surplus electricity. However, the set price for the MPR price and off-peak rates can nonetheless result in average electricity prices that may be insufficient to fully compensate for the electrical generation system costs. Furthermore, the long term contracting terms lack escalation provisions and this can be a disincentive for electrical producers deciding between participating in the feed-in tariff or net-metering programs. However, it may also be possible with suitable gas storage and design that a digester system could be operated beneficially as a peak power operation under the feed-in tariff program so that the dairy sells most during peak or partial peak periods (PERI, 2008).

While the feed-in tariff program improves the revenue potential for on-site electrical production, it does not maximize the economic benefits to the dairy. Under the current feed-in tariff programs, Californian utilities are prohibited by regulation from “wheeling” electricity from the dairy – even amongst the dairy’s own electrical accounts. For example, a dairy farm with several electrical accounts (e.g., for refrigeration, irrigation systems, lighting and home use) will have to sell the power in excess of that it consumes on its producing electrical line (i.e., that connected to the generator system). Under the PPA agreement terms with the utility, the dairy would earn revenues (which may be near to a wholesale price) while at the same time being charged at a higher retail price for the electricity it is consuming on its other electrical accounts. Under this arrangement,

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15 Some industry experts suggest that the MPR is too low to provide sufficient financial support for the development of new renewable energy projects. Consequently, the CPUC is currently also considering the implementation of “reverse auction” as future funding. If approved, potential renewable energy producers could bid the rates at which they would supply electricity. The major utilities would then select the lowest cost bids from qualified producers. Such an approach could enable the producers to contract for renewable energy at higher than MPR rates.
the dairy loses some of its potential avoided cost savings that it could earn if it was able to fully serve its own electrical needs from its own electrical production.

The feed-in tariff program is available on a first-come, first served basis and PG&E’s obligation for the program serving manure digesters and other non-water/wastewater customers will end when 104.6 MW of installed renewable generation will operate under the program. As of February 2010, only the Castelanelli Bros Dairy has enrolled in the program (PG&E, 2010).

The most recent analysis by the CEC predicts that California’s system-wide average retail electricity price will not increase in real terms between 2010 and 2016 (CEC, 2007). If electricity prices remain stable, then there will be reduced economic incentives for on-site electric generation use of dairy digester biogas.

In summary, electricity prices are a direct and fundamental driver of dairy digester feasibility. The revenue boundaries for digesters systems are determined by both the retail prices paid by electrical consumers and the wholesale prices and contract terms by which utilities will purchase any on-site surplus electrical production using biogas / biomethane. The terms of any feed-in tariffs, PPA and other price factors (e.g., time of delivery pricing) will determine and incentivize the dairies’ production levels and use/sale of their biogas. Currently, much of these terms are set by the CPUC regulations and policy which determine not only the MPR but also authorize the utilities’ prices to its consumers and their ability to “pass on” any electrical purchase costs. Similar to other distributed generation and renewable resources, these financial factors may be expected to have an important, albeit complicated role, influencing the economic feasibility for manure digesters in the Central Valley.

**Byproduct Values**

**Digestate Use Values**

Most feasibility studies of dairy digester systems estimate an economic value for use of the digestate by-products. Depending on its water content, the digestate can be spray applied to crops as a fertilizer supplement / replacement, used as compost material or livestock bedding material.

The quantity and form of the digestate will be related to the anaerobic process used. Lagoon digesters will result in predominately liquid digestate while the complete mix digesters typically produces a denser slurry digestate. The plug-flow process results in a wet solid digestate material. The digestate can be heated or otherwise dewatered to separate the solid fraction for use as a compost material or bedding. If a dairy farmer has insufficient land to accept all its digestate, the material can generally be transported short distances to other nearby farm operations. In many cases, the digester owner will earn a small payment for the effluent (Martin, P., 2010).

The extent that the digestate by-product can be used as a soil supplement or fertilizer replacement will depend on the farmland soil conditions and crop types as concerns about salt and nitrate loading limit its land application rates within the Central Valley. Currently, single crop farming in the region can typically accept approximately 2,000 lbs of manure or digestate per acre annually while double cropped fields can receive 3,000 lbs per year. Given that a cow will produce approximately one
ton (2,000 lbs) of manure solid a year, the quantity of digestate that will remain after anaerobic digestion will be approximately 60% or 1,200 lbs per cow per year (Clear Horizons, 2006).  

Some analysts argue that most digestate uses should not be recognized as an additional revenue source for the digester since the dairy’s manure would otherwise be similarly reused on-site. In which case it may be argued that no new net revenue has been generated unless manure or other feedstocks (if co-digestion is occurring) has been imported (Hall, 2010).

In any case, the potential value of avoided bedding costs will be very minor. Although bedding sales of digestate are commonly estimated to be approximately $20 - 25 per ton (Clear Horizons, 2006), according to USDA statistics, less than 0.28 percent of the total dairy budget was spent on bedding and litter materials for the average California dairy operation (USDA, 2005). Consequently the avoided cost of digestate use for bedding or revenues from their sales can be expected to have a minimal if not negligible effect on the economic feasibility of any manure digester systems.

The compost value of digestate is considered to be potentially significantly higher if it can be sold commercially. Green waste recyclers report sales of up to $18 per cubic yard ($90 per ton) (SAIC, 2002). However, wholesale values of the digestate may be far lower. In an analysis of a large centralized digester system Hurley estimates that the net value of the digestate would be $5 / ton which was consist with several other studies (Hurley, 2007).

Again, given the relatively minor net value of the bulky digestate and recognition that it is arguable that any net material gain has occurred (and in actuality likely to have been a 40% loss in biomaterial material weight in the manure to digestate conversion), the value of the solid digestate as a compost revenue may be expected to have a minimal contributory effect to the digester feasibility.

**Effluent Use**

Digester effluent is typically applied to dairy farmers’ fields for feed crop production. As discussed above for the solid digestate, it is arguable whether any revenues or avoided costs associated with the use of the effluent by-product will represent a net revenue contribution. Unless organic feedstock material has been imported (which would increase the effluent quantity and/or fertilizer value), then the farmer’s fertilizer expenditure would be expected to relatively unchanged. Consequently, only co-digesters or centralized manure digester systems would be expected to generate net revenues from digester effluent use that would represent additional revenues potentially improving the project’s feasibility. Furthermore, if the location of the digester has insufficient onsite capacity to accept on-field applications of all the generated effluent (or solid digestate), then disposal of the effluent could add costs that would further decrease the project’s economic feasibility.

The potential applied fertilizer cost savings with effluent use will have greater potential economic than solid digestate uses. Furthermore, unlike the quantity of manure solids which is substantially

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16 Assuming substrate volatile solid content of approximately 65% (i.e., manure with bedding) of which 60% would be converted to methane.

17 Technically, the digestate is not actually compost material since it has not been aerobically decomposed, however it has very similar uses and nutrient value for soil application as compost.
reduced by the anaerobic digestion process, most of the nitrate, phosphorus and, to a lesser extent, potassium content will remain in the effluent and digestate. As a result, any use of imported feedstock will likely add additional nutrients. While such nitrogen and other salt accumulation can present potential water quality concerns if improperly managed, the high costs of fertilizer ensure that effluent can have reuse value to the dairy and other nearby farms.\textsuperscript{18} Farm studies indicate that the fertilizer value of untreated manure can be significant – conservative estimates from a 1997 study estimate the annual value of untreated manure to be over $100 / cow (in 1997 dollars) (Hart, 1997). However, these fertilizer cost saving are also more applicable to higher value commercial crops rather than feed crops. Nonetheless, it can be reasonably expected that on a per cow basis, new net effluent gains would have some positive revenue value for the dairy.

It has been suggested by some industry analysts that large scale effluent treatment to separate out the nitrogen, phosphorous and other salts could generate highly valuable organic fertilizer byproducts that would be suitable for use by drip feed irrigation systems. Such an additional effluent processing component to the dairy digester facility would be costly with developer costs and economies of scale similar to those necessary for biogas upgrading systems. However, given the high costs for fertilizer purchases, the high concentrate organic byproduct would have significant value which according to some experts could be a major economic driver for the digester system (Best, 2010). Furthermore, such a digester effluent treatment system would sequester nitrogen and salt thereby improving the dairy’s water quality management practices.

In general, net effluent gains for co-digesters or community digester systems may represent a positive albeit relatively minor supplemental economic factor for system feasibility (subject to local farmland soil conditions).\textsuperscript{19}

**Tipping Fees (Co-digesters only)**

Most co-digester studies argue that that tipping fees for the feedstocks processed by co-digesters are important revenue sources. Several studies have concluded that tipping fees can be crucial factors is determining the viability of the digester project (Moffatt, 2007).

However, it is essential that the net revenues for sourcing co-digester feedstocks are understood so that the net revenues to the digester project can be correctly determined. “Tipping fees” generally refer to the price paid for disposal of the organic wastes. In some cases, the waste producer may also incur additional transportation costs for removal of the waste. Co-digester operators sourcing feedstocks for their facilities will similarly need to recognize the costs for transportation (and possibility storage) of the feedstock to determine the cost-effectiveness of feedstock additions for their biogas production.

In most cases, waste-to-energy facilities are able to obtain a disposal or tipping fee for feedstocks that increase biogas production and add revenues that assist in offsetting facility construction and operating cost expenses. Such disposal fees currently range from about $50 to $60 / ton in California.

\textsuperscript{18} It should be noted though that the site-specific soil and groundwater conditions may reduce the effluent’s value if the land application rates of local farmland are too restrictive.

\textsuperscript{19} Not including the development of major effluent processing component.
However, most of the feedstocks are potential commodities for which supply, demand and prices are susceptible to change. Relatedly, most commercial feedstocks (e.g., agricultural or food processor wastes) are expected to be available only seasonally and on a short-term contract basis. Digester operators will likely have to obtain a variety of different feedstock materials from numerous sources. Municipal green waste is currently identified as one of the more reliable potential feedstocks. As competition increases for these resources this trend may reverse and tipping fees may decrease. Costs for collection, transporting and storing agricultural residues uses are typically in the range of $25 to $50 per dry ton. Transportation costs of $0.20 to $0.60 per mile per ton are typical for feedstock delivery (Jenkins, 2006). Other analyses have identified loading and unloading costs of $0.40 / ton (2007 dollars) with a $0.18 / ton / mile transportation cost (Moffatt, 2007).

Tipping fees can offer additional revenues for co-digester systems but transportation and storage costs may reduce the net revenues for the digester operator. Given the uncertainties and geographic considerations associated with current and future feedstock commodity values, it is conservatively considered that tipping fees should be recognized as at most a minor secondary supplemental revenue source solely for co-digester systems.

**Greenhouse Gas Emission Reduction Credits**

There are two types of potential greenhouse gas (GHG) credits that may be derived from digester systems: (1) Credits for methane destruction (carbon offsets); and (2) Credits for Fossil Fuel Displacement (renewable energy credits).

Methane has 23 times the greenhouse gas impact of an equivalent weight of carbon dioxide (CO₂). Consequently, each ton of methane that is intentionally destroyed will have an equivalent GHG reduction value of approximately 23 tons of carbon dioxide. Use of renewable fuels for power generation also has a secondary benefit that carbon currently stored in fossil deposits is not added to the environment. Renewable Energy Credits (RECs) in effect account for the fossil fuel displacement effects and are discussed separately below.

A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” (the offset provider must prove that the project would not have happened without its financial investment and that the project goes beyond “business as usual” activity).

The methane collection and use associated with anaerobic digesters systems can result in considerable reductions in GHG releases. Flaring of collected biogas will result in a net GHG impact reduction as the more volatile methane is converted to carbon dioxide which has less than a twentieth of the climate change effect. Productive use of anaerobic digester biogas will result in additional GHG benefits as the biogas generated energy will reduce the corresponding utility generated GHG emissions that would otherwise be necessary.
Currently, there is an emerging international and domestic market for greenhouse gas emission offset credits (often referred to as carbon credits). Both the European Union (EU) and Chicago Stock Market (amongst others) operate “carbon markets” for the purchase and sale of certified carbon credits. In addition, potential GHG credits have to be certified to verify their effectiveness. Numerous organizations operate GHG verification programs both within the U.S. and internationally (e.g., the Voluntary Carbon Standard Association and Gold Standard Foundation). Within California, the California Climate Action Registry (CCAR) has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters.

Presently participation in GHG markets is voluntary within the United States. Nonetheless, many businesses are currently purchasing carbon offsets to support projects that reduce GHG levels. Consequently sales of carbon offsets may be an additional revenue source for future digester projects. However carbon offset prices are subject to market conditions and price volatility. Between 2005 and 2007, carbon reduction credit values were as high as $50 per ton of CO$_2$ equivalent. More recently, carbon values have been considerably lower - typically in the range of $10 per ton. Since the market is based on both the supply and demand for carbon credits, it is difficult to project the future carbon credit values.

PG&E currently operates its Climate Smart program which allows participating customers to elect to pay an additional monthly premium to fund CPUC-approved projects that reduce GHG emissions. Climate Smart acquires 1.5 million tons of carbon credits annually and as such is the largest single carbon credit purchaser in California. Residential, businesses and municipal customers participating in the Climate Smart program are purchasing GHG offset credits which fund renewable energy purchases and development. PG&E estimates a current carbon reduction price of approximately $7 per metric ton of CO$_2$ for its Climate Smart program. Given an annual GHG impact equivalent to 4.6 tons of carbon per year, the current potential carbon offset value for qualified dairy digesters would be approximately $32 per cow (Brennan, 2009).

A central issue for carbon credits is “additionality.” Additionality considers whether the GHG reduction is discretionary and whether the carbon offset purchase actually ensures carbon reductions, or whether the reductions would have occurred regardless. If the carbon offset purchase is a key factor in making the reductions happen, the reductions can be considered to be “additional” to the business-as-usual case. If anaerobic digesters become the Best Available Control Technology (BACT) for dairies’ waste management, then digester collection of methane would no longer represent “additional” carbon reductions and so would no longer qualify as carbon credits. Under such circumstance, existing GHG credits would remain valid until the end of their ten year term but new credits would not be authorized (CCAR, 2007).

**Renewable Energy Credits**

Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.
Renewable Energy Credits (RECs), as statutorily defined, are not created until electricity is generated. Therefore biogas digesters, unlike wind turbines and geothermal facilities, in and of themselves have no RECs to convey. However, if the digester biogas end use will replace the use of fossil fuels for energy production then the digester can qualify for fossil fuel displacement credits.\textsuperscript{20} As a renewable resource that can directly substitute for natural gas use, biomethane or biogas used for electrical generation or injection into the utility grid will qualify for REC credits.

The value of the fossil fuel credits also depends on the fossil fuel use that would be displaced. Consequently, California fossil fuel displacement credit values for electrical generation use are lower than elsewhere within the most of the United States due to the fact that no coal fired power plants operate within the state. Under the State of California’s Renewable Portfolio Standards (RPS) requirements, there is an emerging market for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters. The generation of renewable energy from the dairy digester systems can be quantified and certified for sale as a renewable energy credits.

A digester system developer retains the RECs for self-generated power used on site while the utility receives the remaining REC credits for any surplus electricity it has purchased. Utilities and other entities that need these “green tags” to comply with California’s Renewable Portfolio Standard would be potential purchasers of digester RECs. In addition, other businesses wishing to support renewable energy might also be interested in purchasing digester power RECs. REC prices are subject to market conditions but could be expected to be $0.002 to $0.005/kWh (CH2M Hill, 2006).

Currently, most RECs within California are sold bundled with the associated renewable energy. Consequently, utilities such as PG&E that are negotiating long term renewable energy purchases acquire the REC values with the resource’s material value as a fuel. Consequently, the sale price for the renewal resource has a price premium component for the included REC. However, the REC values for self-generated energy used by the dairy will be retained and would be potentially available for sale and purchased.\textsuperscript{21}

There are no established REC values for biomethane use as a transportation fuel. However, future implementation of the California Low Carbon Fuel Standard (LCFS) is expect by many industry experts to encourage the future of REC values applicable for future use of biomethane (either as CBM or LBM) as a replacement for diesel and gas fuel (Price, 2010). Although very difficult to value at this point in time, some industry experts maintain that the future REC values for biofuels could add additional revenues for digesters systems producing CBM or LMB.

### Other Economic Benefits of Sustainable Farm Production

Currently, several of the farms with operating digester systems receive significant attention for their pioneering sustainability improvements and use of biogas as a renewable energy source. Hilarides Dairies use of cow power for its trucks and Fiscalini Farm’s use of its biogas for its

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\textsuperscript{20} Consequently, biomethane production for use as transportation fuel will not qualify for RECs.

\textsuperscript{21} The sale and purchase of tradeable REC’s for utility compliance with RPS is currently under agency review and consideration by the CPUC.
cheese production are two notable examples. Similarly, the Straus Family and Gallo Farms also differentiate their dairy operations by their implementation of more sustainable farming practices.

However, as yet there is no appreciable market or economic value to these and other California dairies rewarding them for adopting more sustainable business practices. While “greener” businesses in other sectors may be able to leverage their sustainability commitments for an improved market position or marketing benefit, there is currently little potential for dairy farms to capture any such similar benefits. Due to California’s regulated milk sales market and relatively few dairy producers that sell directly to retailers, most dairy farmers are “price-takers” (LaMendola, 2010). Dairies such as Straus Family Farms that have a brand identity and sell their dairy goods to consumers are very few in number and represent a very small portion and niche of the dairy market. Premium prices for “greener” dairy producers are unlikely to be achievable in the foreseeable future particularly during a depressed economy and relatively low public awareness of the potential for more sustainable production practices such as dairy digesters. Furthermore, due to the largely consolidated market for most dairy goods and the perishable nature of milk itself, emergence of any sales premium or selection preference for dairy products from “sustainable” dairy farmers will likely require a considerable increase in prevalence and/or accreditation labeling (i.e., a “green” stamp of approval) before wholesalers and/or other large customers can and will begin to select amongst dairy producers for those more sustainable producers.

As a result, it is considered unlikely that dairy farmers will be able to gain any significant economic premium for their dairy products from their digester operations.

**Government Grants and Assistance**

Currently most operating digester systems receive considerable government funding assistance. Anaerobic digester projects qualify for many of the federal and state programs promoting renewable resource development. Governmental assistance and support can be provided in the form of form grant funding, low-interest loans, tax incentives and/or technical support. The main forms of government support currently available for biomethane production by dairy manure digesters are identified below. Individual digester projects will have to qualify for assistance on a case by case basis and projects will typically receive assistance from only a few programs.

- **Renewable Energy Production Tax Credit.** Under this federal program authorized by the 2005 Energy Policy Act, qualifying renewable energy producers can obtain $0.015/kWh in production incentives. The program is currently authorized to continue until 2026.

- **USDA – Renewal Energy Program.** The program provides grants and loan guarantees to rural small businesses and agricultural producers for up to 25% of the cost to purchase and install renewable energy generation systems up to $500,000.

- **Self-Generation Incentive Program for Renewable Fuel Cells.** Authorized by the CPUC, this utility administered program provides financial incentives for installation of new, self-

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22 The Feed-in Tariff program authorized by the CPUC is discussed previously under the electricity price section.
generation equipment installed to meet all or a portion of the user’s electric energy needs. The program was originally designed to complement the CEC’s Emerging Renewables Program (ERP) by providing incentive funding to larger renewable and non-renewable self-generation units up to the first 1 MW in capacity and subsequently increased for units up to 3 MW in capacity. Renewable fuel cell systems can receive a $4.50 /watt as a one time capital payment (but not to exceed 50% of the total cost). Non-renewable fuel cell systems can similarly receive a $2.50 /watt capital payment.

*California Energy Commission - Renewable Energy Program.* The Existing Renewable Facilities Program provides production incentives, based on kilowatt-hours generated, to support existing renewable energy facilities. In addition, the Emerging Renewables Program provides rebate funding for solar and fuel cells that use renewable fuels (such as biogas). The program has $65.5 million in funding until 2011.

*State Assistance Fund for Enterprise, Business and Industrial Development Corporation: Energy Efficiency Improvements Loan Fund.* This long standing state program offers low interest loans to small businesses in California for renewable energy systems. The maximum loan amount is $350,000 at 4% interest with a five year repayment period.

In addition to these current programs, the State of California (administered by the CEC) provided significant funding assistance to manure digester and other similar renewable resource projects through both its former Dairy Power Production Program and research conducted under its Public Interest Energy Research Program (PIER). As discussed previously in the Renewable Energy Credits discussion, the State of California Renewable Portfolio Standards (RPS) requirements also provides indirect support for manure digesters by fostering an emerging market within California for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters.

Recent economic analysis of dairy digester systems installed under the California Dairy Power Production Program determined that without government subsides, even the best constructed /operated digesters would have electrical production costs that are “high tending to be above market rates” (PERI, 2008). Even factoring in government subsides, the cost of energy for other digester systems were such that while several digesters were marginally profitable, several others operated at a negative rate of return.

Together these past and current programs illustrate the important role that state and federal programs contribute to fostering the development of manure digester systems. The financial and technical support is widely agreed to be an important and positive influence improving the feasibility of manure digester development. Furthermore, given the increasingly complex regulatory conditions facing dairy farms and renewable energy projects, as well as the financial challenges remaining before full commercialization of the manure biogas/biomethane production is expected to occur, continued governmental support is expected to remain an important and essential economic driver for future manure digester development for the feasible future.
Cost Factors

These costs typically will consist of both:

- Initial construction and equipment costs for development of the digester project. In many cases there may be significant economies of scale as the system capacity increases. The construction and/or equipment cost will also likely vary depending on the technology adopted.

- Operating and maintenance cost for the project. This will include the labor and input costs including required energy. Typically, these are variable costs and will vary with the level of production. The operating and maintenance cost may also vary depending on the technology adopted.

The following section identifies the major cost factors that influence the economic feasibility of biogas production by dairy manure digester systems. These factors are naturally inter-related with the revenue factors discussed above. Just as market conditions will determine the revenue potential for digester biogas and its other byproducts, technological and equipment supplier conditions will be key cost determinants on economic viability. Consequently, major technological improvements that greatly decrease unit production costs will enhance the economic feasibility of dairy digester development. Conversely, additional equipment / processing requirements (i.e., as result of new regulatory compliance requirements) that increase unit production costs will reduce the dairy digester system’s economic viability.

As will be discussed below, economies of scale can have an important role determining unit production costs and consequently the economic feasibility of the system. In some cases, scale issues will be limiting factors. Major equipment components may require minimum quantities of process throughput to operate adequately and in such cases these technological/operational constraints may dictate system design parameters.

Finally, it is worth noting that costs are generally easier to estimate than revenues which typically face more future variables. This is particularly apparent when the digester system’s operating assumptions and conditions are defined. Review of past digester studies offer far greater cost information than is provided for their revenue projections. In any case, care should be taken to ensure that estimated costs are properly matched with operational / output assumptions. It should also be recognized that site specific conditions can both positively or negatively affect the actual system development costs considerably.

Manure Collection / Preparation as Feedstock

The dairy manure collection costs for on-farm digesters are considered to be negligible since similar manure management practices are already a necessary component of existing dairy operations. Furthermore, the transportation distance within the farm will be very limited. In addition, relatively little pre-digester preparation is expected to be necessary for the manure. Any grinding or filtration necessary will be very minor in cost compared to the digester itself.
For a centralized or community digester system, manure transportation costs may be a limiting factor that could offset economies of scale that might be gained from larger anaerobic digester facilities. Manure from the individual farms could either be piped to the centralized digester through a sewer system or possibly be transported by trucks. Analysis by Ghafoori and Krich suggest that development of a piping system for dairy manure is prohibitively high from a construction cost basis (Ghafoori, 2005; Krich, 2005). Furthermore, such systems would incur major additional investment cost and could face significant additional difficulties with site and easement requirements.

**Anaerobic Digester Systems**

As discussed previously, anaerobic digester systems are relatively simple and well established technologies. Although there is potential for future productivity improvements, construction specifications and costs are relatively well defined. Most of the system components are relatively standard and readily available. Other construction costs (e.g., such as siting and land preparation) will be relatively straightforward.

The selection of specific anaerobic digester technologies will be primarily determined by the dairy’s manure management systems. While site specific requirements may necessitate some tailoring of digester configurations, construction costs should be relatively comparable between dairies located within the region. As a relatively simple and mature technology, future equipment and development costs for anaerobic digesters are not expected to change substantially. Future technological improvements are expected to be predominantly incremental. Therefore, while digester system construction costs will represent a secondary factor in determining the economic feasibility of manure digester systems, this cost factor is expected to remain relatively constant and therefore represents a minor economic driver.

Operating and maintenance costs for digester systems remain largely under-analyzed. If feasibility studies consider the system operating and maintenance costs at all, most typically attributed a percentage cost of the project’s construction cost. While improved remote sensing and automated control systems can assist digester management tasks, many industry analysts agree that most studies do not fully recognize the labor likely involved to operate digester systems (Summers, 2010).

In any case, given the comparative simplicity and mature technology used for manure digester systems, operating and maintenance costs may be expected to make a very minor contribution to the digester overall economic feasibility. Furthermore, no significant cost improvements can be expected to the anaerobic digester process that would substantially improve overall system feasibility.

**On-site Heat/Boiler System**

On-site heat generation from biogas is predominantly used for heated complete mix or plug flow anaerobic digester systems. Otherwise, unless major milk processing is occurring on-site, most dairy’s heating demand will be relatively limited and can be met with standard boiler systems that can be fairly easily modified for use with biogas (although air quality compliance may be problematic). The capital cost for conversion or purchase of suitable heating systems will be relative minor. In most cases, heat generation will be limited and only a secondary use for dairies of any produced
biogas. Therefore, heating use of biogas will have a very minor influence on the digester’s economic feasibility. Furthermore, no major technological improvement or future significant cost savings can be expected related to biogas heating systems that would improve overall system feasibility.

If on-site electrical generation with biogas is planned, combined heat and power (CHP) designs typically can offer cost effective opportunities to use thermal energy that would otherwise be lost. However, given most farm’s limited heating needs it likely that surplus heat would still be generated. Consequently, while their may be opportunities for cost effective efficiency gains, the magnitude of the economic benefits will remain minor and will not be expected to be a significant economic driver of system feasibility.

**On-site Electrical Generation**

As discussed above, on-site electrical generation has generally been the primary use of biogas produced by on farm digester systems. Except for the Vintage Dairies facility which is producing biomethane for pipeline injection, all the other manure digester systems operating in California are using their biogas production to produce electricity on site.\(^{23}\) Electrical generation with internal combustion (IC) engines is a very well established technology that can be applied at both the full range of production scales and under a wide variety of operating conditions. Generally speaking, outside California, electrical production with internal combustion engines can be cost effectively performed to meet not only all on-farm needs but also to generate surplus electrical energy which can be exported to other users or to the grid under net-metering or distributed power arrangements with local electrical utilities.

The national average on-site electrical usage for dairies is 550 kW / cow / year (Barker, 2001). At a typical retail energy cost of $0.12 kWh, the annual electrical cost for each dairy cow would be $66. If it is conservatively projected that each dairy cow can generate 0.1 kW/hr, then an annual basis total value of the potential electrical production would be 876 kW/cow/year which would be worth approximately $105 per year per cow of which approximately $39 per year would be the potential value of the surplus electricity at average retail electricity prices.

Yearly operation and maintenance costs for electrical generation systems are typically estimated to be in the range of $0.015/kWh (Jewell et al., 1997; Hurley, 2007) which reduces the system operator net revenues/saving.\(^{24}\)

However, as discussed in more detail below, future electrical generation with biogas at dairies within the Central Valley is highly problematic due to recent air quality regulations that prohibit IC engine use unless NOx emissions can be reduced to 9 – 11 ppm or less. It is currently unclear whether the use of on-site electrical generation equipment can be cost-effectively applied in the near term for dairy digester systems in the Central Valley.

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\(^{23}\) Hilarides Dairy also produces compressed biomethane with some of its digester biogas for use as a biofuel by its specially converted trucks.

\(^{24}\) Although as discussed under the Electricity price section, under the net metering program additional tariff costs for transmission and distribution, as well as demand charges may also be incurred. In addition, the interconnection process prescribed by CPUC Rule 21 can also require additional costs to the dairy.
On-site generation of electrical power is an important potential use option for dairy digester biogas/biomethane. As a form of distributed power, such on-site systems offer possible direct economic benefits and reduced overall environment impacts. However, given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically infeasible in the Central Valley until major improvements in the technical capabilities and costs for new microturbines or fuel cells are achieved.

**Biogas Upgrading**

The fundamental purpose of biogas upgrading is to increase the proportion of methane from its 50 to 65% concentration to near pure methane (95-99%) while removing the corrosive $\text{H}_2\text{S}$ and $\text{CO}_2$ impurities.

The specific gas quality standards for biomethane to be accepted into the PG&E natural gas system are set in PG&E Gas Rule 21.C and by Rule 30 requirements for SoCalGas. Key utility specifications include less than 1% $\text{CO}_2$ and 4 ppm of $\text{H}_2\text{S}$ content.

The upgrading requirements for biomethane production to pipeline injection standards are comparable (and typically higher) than those required for CBM or LBM production. Therefore the primary economic differentiators between biomethane uses (e.g., pipeline injection, compressed biomethane or liquefied biomethane) will be associated with subsequent delivery and market requirements for the different uses.

There are three main processes necessary for refining biogas into biomethane. The technologies for each of the procedures are well established and widely used but generally are implemented at a scale far larger than the production levels that even large dairy digesters would be able to attain based on its own herd size.

**Scrubbing ($\text{H}_2\text{S}$ removal)**

Hydrogen sulfide ($\text{H}_2\text{S}$) is a highly corrosive impurity within biogas as it readily combines with water to form sulfuric acid. Generally, $\text{H}_2\text{S}$ concentrations in raw biogas are typically 0.5% or less and can be problematic for many gas uses. However, for “lower tech” applications (such as boiler systems or internal combustion engines) regular and increased maintenance can be used to cost effectively manage most of the potential corrosion effects. Of the numerous potential scrubbing processes, iron sponge scrubbing is generally considered the most suitable for on-farm $\text{H}_2\text{S}$ removal (Krich, 2005).

**Conditioning**

Water removal from biogas is a relatively straight forward and can be achieved through refrigeration of the biogas to condense out the water content. Using a relatively inexpensive commercial refrigeration unit and minor parasitic energy loss (2%) the water content in the biogas can be adequately reduced to acceptable levels.
Carbon dioxide is the most critical and expensive impurity to remove from biogas. Due to its relatively inert chemical composition and high concentration levels within the digester biogas, more extensive gas treatment is necessary for carbon dioxide removal. Water scrubbing is a relatively simple and low cost conditioning that is considered suitable for on-site dairy use. Although less efficient than other “higher tech” approaches, water scrubbing is most environmentally benign. Alternatively pressure swing adsorption (PSA), amine scrubbing and other technologies are available which offer some advantages for some applications (e.g., compatibility with LBM ) but also present cost or environment byproduct disadvantages.

Biogas upgrading is likely necessary for any off-site use of digester biogas. The processing equipment, and to a lesser extent, the operating and maintenance costs, required for biomethane production will add considerable cost to the digester system. As a result, the unit cost for the biomethane will be increased substantially. While increasing the size of production levels can help to lower the unit cost of production, the volume of production necessary for most applications of the scrubbing and conditioning equipment remain relatively high due to the fixed cost of the technology. Furthermore, diseconomies of scale may begin to be incurred if the digesters can not be favorably located and clustered. Several previous feasibility studies have suggested that biogas upgrading systems would need to process the biogas of 10,000 cows although other suggest that full production cost efficiencies for pipeline injection would require 30,000 cows (Goodman, 2010).

As a result, unless future technology improvements can cost-effectively scale down biogas upgrading systems, it is likely that current biogas upgrading technology requirements will remain a major factor restricting economic feasibility.

**Distribution / Transmission System**

The construction costs for biomethane pipelines can vary considerably. Typically pipeline costs are estimated to range from $100,000 to $250,000 per mile. While the operating cost for pipeline delivery will generally be very low, the initial construction will represent a significant additional investment cost – especially compared to tanker truck delivery. Given the comparatively high cost for pipeline delivery, it has generally been judged that pipeline delivery of biomethane for any significant distance will not be economically feasible. Some analysts suggest that at most one or two miles in most cases would be a limiting distance for pipeline use (Krich, 2005). Others maintain that up to five miles may be viable under certain conditions (Brennan, 2010).

Pipeline distribution costs also will play a fundamental role determining the feasibility of a centralized biogas treatment facility serving several dairy digester systems. Cost effective development of a centralized biogas treatment facility will require the farms’ digester systems to be clustered close together. Furthermore, the combined biogas production must be sufficient to ensure an adequate supply to attain the necessary economies of scale for cost-effective biogas upgrading. Otherwise, the pipeline transmission costs to import the additional biogas from more distant producers may place additional cost burdens that undermine the collective enterprise’s overall feasibility.

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*25 PVC like pipe materials are also available for raw biogas transmission. However, as an even lower-grade and less valuable fuel it is will be less economically feasible to transport than the refined biomethane.*
One advantage of pipeline injection for biomethane is that only limited on-site gas storage facilities will be necessary. CBM and LBM production will require both storage and truck transfer facilities. Standard and relatively inexpensive propane tanks can be used for low pressure biomethane storage (i.e., up to 300 p.s.i.). This is most suitable as intermediate storage of the biomethane output from the upgrading facility. Biomethane must be further compressed to 3,000 to 3,600 p.s.i. (i.e., equivalent to CNG pressure) for delivery and use as a transportation fuel. LBM has to be liquefied at pressures of over 5,000 p.s.i and maintained at low temperatures. Such high pressure storage is expensive and relatively complex to maintain.

**Pipeline Injection**

Currently, although California utilities are willing and able to purchase biomethane produced by manure digesters, the supplying dairy must provide all the facilities necessary to deliver pipeline quality biomethane to the utility’s natural gas transmission system. Furthermore, the dairy (or third-party developer) must also perform the scrubbing and compression of the biomethane as well as install and operate the metering equipment and pipeline tap (Brennan, 2010). In addition, proximity to the natural gas transmission line will also be a major limiting factor. As discussed earlier, pipeline delivery costs will likely ensure that any biogas/biomethane production facilities for pipeline injection will have to be located at most a few miles from suitable connection locations to the transmission line.

Biomethane producers injecting biomethane into the existing natural gas transmission pipeline will incur an interconnection cost. Interconnection costs to the biomethane producer will vary depending on the utilities being served. Recent estimates for the connection cost for biomethane injection into PG&E transmission system are $0.265 million for biomethane producers injecting less than 500,000 cu.ft. per day. SoCalGas will charge biomethane producers the same rates as those for a tradition natural gas interconnection. Projects injecting up to 1 MM cu.ft. / day will pay approximately $0.8 million to access the SoCalGas transmission system (Anders, 2007).

The connection costs for pipeline injection are considerable and will require a greater scale of production so that the added costs can be adequately distributed to result in a manageable unit cost basis. In any case, the utility connection costs will represent a significant factor reducing the potential economic feasibility of biomethane production from dairy digesters. Furthermore, pipeline injection use of digester biomethane will be geographically constrained due to the high cost for any pipeline or vehicle transport of the biomethane between the digester and suitable injection points which must be along the natural gas transmission system.

**Compression / Liquefaction**

Methane requires 5,000 psi for liquefaction and it requires major applied energy to attain. Compression of biomethane only to 1,000 psi requires approximately 207 Btu of energy to compress each 1,000 Btu – a considerable parasitic energy “loss” or cost of 20.8 percent (Hansen, 1998). This does not include efficiency losses associated with the compression engines themselves.

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26 PG&E will provide the pipeline tap and metering equipment for large suppliers (i.e. those delivering 500 M cu.ft. or more per day).
There are major scale constraints for liquefaction and distribution of biomethane. Due to the cryogenic nature of liquid biomethane, significant energy must be used to maintain the produced LBM at very low temperatures to avoid the liquid “boiling off.” The potential energy losses for storage of LBM can be significant. Therefore, industry analysts suggest that liquefaction facilities should at a minimum be sized to produce adequate LBM to fill a standard tanker truck (approximately 10,000 gallons) every three or four days to reduce on-site storage losses.

**Biomethane for Fuel Use and Conversion Costs**

In recent years, the State of California has conducted extensive analyses and taken several actions intended to encourage the development of alternative vehicle fuels including Executive Order S-06-06 and most recently Executive Order S-01-07 (the Low Carbon Fuel Standard) requiring a 10 percent reduction in the carbon intensity of transportation fuels by 2020. Currently, compressed natural gas (CNG) is used as a petroleum alternative for cars and other light use vehicles. In addition, liquefied natural gas (LNG) is also being developed as a fuel source suitable for heavier industrial vehicles. While new CNG and LNG vehicles are available for commercial purchase, the existing market is relatively small and these alternative fuel vehicles are more costly. In addition, some diesel and other vehicles can be retrofitted to use a natural gas fuel. However, the costs are considerable and even high-use vehicles will have a long payback period from an economic feasibility perspective.

Compressed biomethane (CBM) and liquefied biomethane (LBM) are both potential substitute fuels for CNG and LNG vehicles. However, as with the CNG and LNG markets, although demand has been growing, this alternative fuels market is still at an early stage of development. Currently the majority of CNG and LNG vehicle fleets belong to municipalities. While this may offer some opportunities for partnerships, these will be geographically limited and will have a very finite demand until wider public adoption of CNG or LNG occurs. In addition, greater adoption of CNG and LNG as alternative fuels also faces strong competition from ethanol and biodiesel, which to date have received considerable and greater federal and state support.

Currently, nearly all of the LNG within California is imported over land in its liquid form by truck. Therefore, until planned LNG terminals in Southern California are completed, LBM produced in the Central Valley could have a transportation advantage over LNG. However, it is unclear whether the magnitude of this transportation cost savings will outweigh the higher production costs currently projected for LBM.

Consequently, the market potential for CBM and LBM is far from assured and participation as a fuel provider will face additional production costs (vehicle conversion, possible development of on-site fueling infrastructure). Therefore, given the absence of clear market demand and purchasers, the feasibility of production of CBM or LBM for bio-fuel sale is uncertain since it is difficult to determine the likely market price that producers would actually be able to obtain.

**Overall Digester System Construction Cost Estimates**

As discussed above, the capital costs for manure digester systems’ construction and equipment costs will vary depending on both the size and configuration of the planned system. Irrespective,
even the simplest of manure digester systems are relatively costly. Table 2 shows the costs and grant funding obtained for nine dairy digester systems in California. The cost estimates include the electrical generation facilities.\(^{27}\)

<table>
<thead>
<tr>
<th>Dairy</th>
<th>Digester Type</th>
<th>Size (kW)</th>
<th>Annual Energy Production (KWh)</th>
<th>Debt Capitalization</th>
<th>Equity Capitalization</th>
<th>Capital Cost (a)</th>
<th>Capital Cost (a) ($/kWh)</th>
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</thead>
<tbody>
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<td>500</td>
<td>3,383</td>
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<td>40%</td>
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<td>31%</td>
<td>69%</td>
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<td>Blakes Landing</td>
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<td>253</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
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<tr>
<td>Castelanelli</td>
<td>Covered Lagoon</td>
<td>160</td>
<td>1,135</td>
<td>0%</td>
<td>57%</td>
<td>43%</td>
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<tr>
<td>Koetsier</td>
<td>Plug Flow</td>
<td>260</td>
<td>540</td>
<td>0%</td>
<td>0%</td>
<td>100% (a)</td>
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<tr>
<td>Van Ommering</td>
<td>Plug Flow</td>
<td>130</td>
<td>489</td>
<td>0%</td>
<td>46%</td>
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<tr>
<td>Meadowbrook</td>
<td>Plug Flow</td>
<td>160</td>
<td>1,100</td>
<td>0%</td>
<td>45%</td>
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<td>IEUA</td>
<td>Modified Mix Plug Flow</td>
<td>943</td>
<td>7,572</td>
<td>0%</td>
<td>1%</td>
<td>99% (a)</td>
<td>$14,543,000</td>
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<tr>
<td>Eden-Vale</td>
<td>Plug Flow</td>
<td>180</td>
<td>457</td>
<td>0%</td>
<td>37%</td>
<td>63%</td>
<td>$904,000</td>
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</tbody>
</table>

a  Capital Costs have been adjusted for inflation into 2010 dollar terms.

b  Koetsier and IEUA received their subsidies as 5 year production payment instead of grant funding.


Other studies report similar cost estimates for developing dairy digester systems. Recent analysis for comparably sized dairy digester systems in Vermont reported capital costs between $4,000 to $7,800 per kWh in 2010 dollar terms (Dowds, 2009). Similarly, the approximate initial total cost for developing a 400kW digester system at Fiscalini Farms in Modesto California was reported to be over $2 million, equivalent to more than $5,000 per kW in 2010 dollar terms (Gannon, 2008). However, subsequent additional design and development requirements resulted in a final system cost of approximately $4 million of which only $1.4 million was obtained from grant funding (Dairy Today, 2010). The Gallo Farms Dairy estimates that the cost of its 700 kW digester system was approximately $3.5 million in 2010 dollar terms which is equivalent to a $5,000 per kWh capital cost (Pacific CHP Application Center, 2010).

As discussed above, digester systems developed for production of biomethane will require considerable additional upgrading equipment to remove the CO\(_2\) and other impurities. In addition, compressor and storage systems will be needed if liquefied or compressed biomethane is to be produced. If the upgraded biomethane is to be injected to the utility pipeline then pipeline injection may require additional on farm (and possibly off-farm) pipeline to the utility’s natural gas transmission line as well as interconnection, controls and monitoring facilities to ensure the quality of gas supplied to the utility.

\(^{27}\) As discussed earlier, new digester development for electrical production will incur substantially higher equipment costs as more expensive generation system are now required to meet subsequent and more stringent air quality standards limiting NOx emission to 9ppm.
As discussed previously, most current biogas upgrading systems require relatively high gas throughput volumes for optimal performance. Consequently, biomethane production will incur additional costs from both increased scale of production as well as the additional facility and equipment requirements. Industry experts currently maintain that at a minimum manure for 10,000 cows would likely be necessary (without co-digestion) to generate sufficient biogas to supply a biogas upgrade facility to operate efficiently. While dairy farms would not need to invest in electrical generation systems, there would nonetheless be major additional cost for farm-sized biomethane production. Preliminary cost estimates for the CEC project interconnection costs of $250,000 and pipeline costs of at least $50,000 for the existing California digesters (PERI, 2009). The cost for biogas upgrading facilities was estimated to vary from $400,000 to over $750,000 (depending on the plant capacity). The saving from the reduced electrical generation capital cost also varied greatly from as high as $800,000 for Hilarides Dairy to just under a $100,000 for other dairies. Excluding the Blakes Landing and Castelanelli Dairies which were 5 miles or further from a suitable utility connection site, the total net additional capital cost for pipeline injections was generally $500,000 to $700,000 higher than for on-site electrical generation (PEIR, 2009). The study also projected that there would be a 15 percent loss of the original biogas quantity by the upgrading process.

Although preliminary and specific to the existing digester systems, the PERI cost analyses demonstrates the considerable additional capital cost involved in dairy digester development for biomethane production.

**Implementation Factors**

**Farmer Interest**

Dairy production is the core business for dairy farm owners most of whom also must manage some feed-crop production on their farms. Modern dairy farm management is itself a complex business requiring considerable time and expertise to successfully manage milk production and maintain regulatory compliance. This is particularly true during recent years as a poor national economy has adversely affected the California Dairy industry. Although 2008 was a year of record production with high milk prices, in the first half of 2009 dairy producers faced increased production costs – partly from increased feed costs resulting from reduced production as many Midwestern crop farmers shifted their production to feedstock crops for bio-ethanol production. For the first quarter of 2009, the average cost of production for California dairy farmers was $18.51 / cwt. More importantly, as a result of overproduction and reduced foreign demand, milk prices fell by early 40 percent between 2008 and 2009 to $10.47 / cwt - their lowest level since June 2003.

Furthermore, feed expenses represent the majority of the dairy farmer’s cost. In 2005, nearly 58 percent of the average Californian dairy farmer’s total cost of production was spent on feed while less than 3 percent of the total dairy budget was spent on electricity, fuel and lubrications for the farm operations (USDA, 2005). Consequently, the potential direct energy and/or fuel cost savings

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28 For farms located 5 miles from a suitable transmission utility connection site the pipeline cost was $1 million.
29 Except for Hilarides Dairy which had an unexplained but very major cost saving (approximately $788,000 in 2007 dollars terms) for replacement of its electricity generation equipment.
from a digester will represent, at best, a very minor benefit to the farm’s budget and any such savings may be easily outweighed by any feed price changes.

Not only must dairy farmers be willing to accept the necessary investment and operating risk to develop digester systems, farmers must develop the technical capabilities and have sufficient professional interest in assuming the secondary occupation of biogas production (Sempra, 2009).

In the face of such volatility and adverse economic conditions, without clearly attainable net financial earnings, few dairy farmers may be expected to assume the additional costs, risks and responsibilities necessary to develop dairy digesters.

**Capital Availability**

The interest rate associated with the initial capital investment (and to a lesser extent managing the operations cash flow needs) will play an important role in determining digester feasibility. Low interest loans and favorable tax depreciation allowances can have an important contribution in reducing the loan repayment burden that a facility must support.

The useful project life for digester systems will have an important role in affecting the economic feasibility of proposed digester and related biogas treatment facilities. A longer useful life will increase the period over which the facility’s capital investment can be earned back. However, due to the interest and inflation effects to the capital investment, future earnings at later periods in a facility’s operations typically will have a lesser contribution to offsetting the initial capital investment.

There are two key factors determining the availability of capital for farm digester systems. First, the dairy farm’s financial situation will be a fundamental determinant of its ability to borrow capital. The amount of equity that a dairy has in its business, its cash flow and the amount of the loan required will determine the likelihood that the farmer can qualify for a loan. Given the recent financial challenges facing the Californian dairy industry, it is expected that few dairies will be able to qualify for the necessary loans from commercial banks to fund the development of major digester facilities.

In addition to the dairy’s financial position, commercial banks must also be willing to provide the loans. Given the currently tight credit market facing the entire economy and the dairy industry’s current poor market conditions, it may be expected that many banks will be unwilling to provide lending for digesters – especially under relatively favorable terms.

Therefore, due to the challenges facing the dairy industry and the generally weak credit market, few dairies are expected to be in the financial position to fund digester development.

**Third Party Developer Assistance**

Third party developers can be expected to be important for the development of future on-farm or community digester facilities within the Central Valley. As discussed above, most dairy farmers are likely to be unwilling or unable to develop manure digesters systems themselves. Third party developers will likely be better able to collect and manage the investment and have the expertise necessary for effective digester development. The ability for third party developers to negotiate
and manage favorable Small Renewable Generator Power Purchase Agreement (PPA) with utility companies is also likely to be a key advantage for future digester system development.

The commercial interest rates and the related return on investment (ROI) sought by private developers will be important determinants of the economic viability and future development of digester facilities in the Central Valley. The ROI that developers will apply to digester systems will be a function of both commercial interest rates and the profit and risk premiums associated with any digester facility venture. The risk facing developers can be reduced by favorable market conditions (e.g., long term contracts with utilities or other biogas/biomethane consumers) and will also be related the supply conditions (such as the extent that the production technology and equipment is well established, widely adopted and/or transferrable to other commercial uses).

Due to the technological, market and regulatory risks associated with biogas/biomethane production, the returns on investment that potential venture capitalist or other third party developer will seek from any digester investment will be significantly above the returns required for other more established industries or businesses. Within the energy industry, potential investors typically seek payback periods of three to five years (Cheremisinoff, 2010; Best 2010). Within the published digester feasibility studies, the payback periods and return on investment rates applied vary considerable – partly given the differences between financial feasibility analyses (reflecting commercial investors’ profit requirements and capital terms) and economic feasibility studies (that represent agency or public policy perspectives) where the cost of money will be substantially lower and profit earning not applicable. Recent analyses for the California Energy Commission have applied rate of return estimates of 17% for their feasibility analyses (PERI, 2008).

While third party developer participation may be an important component of future digester development, their participation is fundamentally a reflection of the economic feasibility of dairy manure digesters and market context. Consequently, they may be considered to play an major role but will be an indirect economic driver since its will be the fundamentals of other market conditions that will determine the role and extent of their participation in the future digester development within the Central Valley.

**Environment Compliance and Regulatory Requirements**

In general, dairy operators face increasingly stringent state environmental regulations requiring dairy operators to adopt more advanced methods to manage their operations. The requirements of Senate Bill (SB) 700, San Joaquin Valley Air Quality Management District (SJAQMD) air quality regulations and Central Valley Water Board (CVWB) waste discharge regulations are examples of such rules. Anaerobic digesters, composting systems and other more costly waste management approaches are replacing traditional land application of dairy manure as accepted manure management practices. Consequently, if the economic returns of digester systems can be improved, then their greater implementation can be encouraged, which in turn will result in overall reduced air and water quality impacts.
Water Quality Compliance

Until relatively recently, most dairies located within the Central Valley Water Board jurisdiction operated under a waiver of waste discharge requirements. In May 2007, the Central Valley Water Board adopted Order No. R5-2007-0035 (Waste Discharge Requirements General Order for Existing Milk Cow Dairies). The order serves as general waste discharge requirements for discharges of waste from existing milk cow dairies and requires dairies to submit a Report of Waste Discharge prior to construction of an anaerobic digester.

The additional water quality requirements in the order have added considerable costs and restrictions. Farmers are now required to manage their applications of nutrients to their farmlands and otherwise protect their groundwater resources. The key water quality concerns for dairy digester systems are the potential for adverse groundwater impacts from dairy waste or digestate stored within farm lagoon systems and the added salt and nitrates from the importation of co-digester feedstock. The CVWB estimates that a typical 1,000 herd dairy produces approximately 3,600 tons (dry weight) of manure per year containing 180 tons of nitrogen and 235 tons of inorganic salts (CVWB, 2007).

Unless, landowners can prove that their farm’s specific site conditions will not result in water quality impacts, the primary compliance approach will be construction of more expensive Tier 1 lagoon systems. Currently, the CVWB is in the process of completing a comprehensive salinity management program with the State Water Board to address salinity problems within the Central Valley. However, until the new plan and program is completed, there are no general salt standards. Consequently review of dairy farm waste discharge compliance plans are performed on a case by case basis and the salt impacts of co-digester digestate are poorly understood, making it more difficult and costly for dairy farmers to comply with the water quality requirements.

Depending on the specific soil and groundwater conditions, some farms are required to install doubled lined lagoons (e.g., Tier 1) and/or reduce their application rates of liquid digestate or solid manure to comply with the state regulations. Salt accumulation issues within the Central Valley are likely to persist and there are currently limited management options for reducing the potential water quality impacts associated with accumulated salts.

Current regulatory differences between dairy and non-dairy farms also limit the ability for dairy farmers to export their manure or digestate to neighboring farms. While exportation of solid manure and/or digestate to other farms is permitted with little water quality regulatory oversight, a similar transfer of digestate effluent requires the recipient farm to comply with the WDR manure management testing and verification procedures. Although the recipient farmer could beneficially use the effluent to meet its fertilizer needs, faced with the regulatory requirements many farmers will instead elect to purchase and apply chemical fertilizer. The resulting outcome adds new nitrates locally (i.e., from the chemical fertilizer use) and reduces the options for manure digester operators to manage their nitrate load. In particular, wet system digesters (e.g., covered lagoons) that can not use all their digestate on site will likely have to reduce the water content of their effluent if the dairy farmer needs to export some of the material to meet the water quality standards. In which case, for the farmer to make the off-site transfer it will face added costs, energy use and water losses. Such offsite liquid

30 Central Valley Salinity Alternatives for Long-Term Sustainability (CV-SALTS)
digestate transfer issues could potentially be an even more significant regulatory issue for a community digester or co-digester operation (Martin, P., 2010).

**Air Quality**

The California Air Resources Board (CARB) is responsible for regulating air emissions within the state. CARB is the lead agency for implementing the AB32 Scoping Plan which is the action plan for California to reduce its greenhouse gas emissions substantially by 2020 with additional reduction by 2050. California farms were generally exempted from air quality regulations until the enactment of SB700 in 2003, which required most dairy farmers and other large confined animal feeding operations (CAFO) to obtain air quality permits for their operations from their local air district. Although rules vary between air districts, dairies that require air permits are now generally treated like other industries.

The San Joaquin Valley Air Pollution Control District has implemented several rules that apply to dairy operations including Rule 4550 (Conservation Management Practices [CMO] Plans), and Rule 4570 (Confined Animal Facilities). In the SJVAPCD new and modified dairies are subject to the New Source Review Rule – District Rule 2201, which requires Best Available Control Technology (BACT), Public Notice, Health Risk Assessment (HRA) & Ambient Air Quality Analyses (AAQA). For the SJVAPCD to issue permits, the projects are also required to comply with the California Environmental Quality Act (CEQA).

While the dairies are adapting to the new rules, the New Source Review Rule BACT requirements for NOx and SOx emissions from electrical generation equipment are cited as a real economic challenge for the dairies. There are several approaches to electrical generation but the systems are expensive to operate and poorly suited for dairy biogas or biomethane use.

The following is detailed updated information from Ramon Norman at the SJVAPCD describing the current requirements related to strict NOx emission limits (Norman, 2010).

“For projects proposing to generate power from biogas in the San Joaquin Valley, the main pollutants that the District is concerned about are NOx and SOx. This is because these pollutants are precursors to ozone (NOx) and particulate matter (NOx and SOx). The San Joaquin Valley Air basin will soon be classified as extreme non-attainment for the Federal 1-hour ozone standard (and the now revoked Federal 8-hour ozone) standard - the worst classification. The San Joaquin Valley Air basin is also classified as non-attainment for the Federal PM2.5 standard. Because of the air quality problems in the San Joaquin Valley and reductions in NOx are critical to the District’s attainment strategy, the District is now requiring more stringent emission controls (such as catalysts) for biogas-fired engines and evaluating alternative equipment (fuel cells, microturbines, etc.) to further reduce NOx emissions down to 0.15 g/bhp-hr (around 9-11 ppmvd @ 15% O2) or less as BACT for these operations. This BACT level has been in place for fossil fuel-fired engines in the District for a number of years but the District is just beginning to apply this BACT level to biogas-fired engines. To meet the District BACT for NOx from these installations, controls (catalysts) would need to be added to an engine or an alternate technology, such as microturbines or fuel cells, would need to be used. Because the San Joaquin Valley is classified as non-attainment for the Federal PM2.5 standard and SOx is an important precursor for PM2.5, emissions of SOx must also be
minimized. To meet the District BACT for SOx from these installations, scrubbing of the gas to remove H2S (down to 50 ppmv) prior to combustion will also be required. Because the San Joaquin Valley Air District is classified as attainment for the CO Ambient Air Quality Standard, BACT is usually not triggered for CO and engines would only be required to meet the 2,000 ppmvd CO limit from District Rule 4702.

At a minimum, any flares proposed for a digester system would need to satisfy the "Achieved in Practice" Category in the District's BACT Guidelines, which currently require a low-NOx flare with NOx emissions ≤ 0.06 lb/MMBtu. Any flares proposed for a digester would also need to satisfy the requirements of District Rule 4311, which requires enclosed flares to meet certain NOx and VOC emission limits and to be source-tested annually. Open flares (air-assisted, steam-assisted, or non-assisted) with flare gas pressure is less than 5 psig must be operated in such a manner that meets the control device requirements of 40 CFR 60.18. Emergency flares, which are exempt from the previous provisions, are required to maintain records of the duration of flaring events, the amount of gas burned, and the nature of the emergency. The requirements of District Rule 4311 can be found at the following link:


Any boilers or process heaters proposed for a digester system and rated 5.0 MMBtu/hr or greater would need to satisfy the requirements of District Rule 4320, which requires biogas-fired units to meet a NOx emission limit of 12 ppmv @ 3% O2 and also requires periodic source testing and emission monitoring. The requirements of District Rule 4320 can be found at the following link: http://www.valleyair.org/rules/currntrules/r4320.pdf.”

Mr. Norman also provided a list of suppliers of equipment that may be able to satisfy the District’s BACT requirement for NOx from power generating equipment that combusts biogas (Norman, 2010).

**Inter-Agency Co-operation and Co-ordination**

Fundamentally, there is a major challenge for finding a mechanism and forum for facilitating inter-agency co-operation and co-ordination. In a comprehensive cross resource perspective, manure digesters are generally recognized to offer significant net environmental benefits. However, since these benefits extend across several resource areas (i.e., air, water and energy use) and are not fully recognized by market mechanisms (e.g., odor and greenhouse gas reductions) balancing impact tradeoffs remains difficult. Currently methane emissions from dairy operations are not regulated. As a result, while the negative air quality impacts of the NOx emissions are recognized, the corresponding (albeit different and less localized) air quality benefits of the methane destruction are not. Furthermore, there is not an easy mechanism for valuing the societal tradeoff of the beneficial energy capture (i.e., the produced electricity) from a resource that otherwise would have its entire energy resource value lost.

The complicated regulatory environment facing dairy operators is widely considered to be a major obstacle to future anaerobic digester development within the Central Valley. Several industry participants and analyses recommend that continued CEC and CPUC support to address technical and commercial risks is important for future development of manure digester systems in the Central Valley (Dusault, 2010). Improvement to the permitting process for complex projects with cross
resource impacts such as anaerobic digesters is generally recognized as important and necessary for encouraging future development of manure digesters. A centralized and stream-lined permit process that reduces the regulatory burden would greatly facilitate future dairy digester development.

**Utility Cooperation**

There is currently some mismatch between utilities interests and needs for digester development. Although there are some regulatory restrictions to utilities, there are many potential opportunities for a supportive utility role to bridge the existing market gaps and barriers to digester development. Support by utilities in this early stage of market development could have a significant positive role. Potential for utility participation in future projects is particularly important for the biomethane conditioning projects. SoCalGas is investigating the feasibility of potential cooperation and involvement in future biomethane production projects for pipeline injection with Sempra Energy (Goodman, 2010).

Several experts suggested that the market for future biogas would be improved if utilities such as PG&E were willing to invest, operate and maintain the necessary upgrading facilities required for pipeline injection. While such an approach would reduce the technical and investment burden on third party or dairy digester owners, the significant production costs for pipeline injection would remain high as only minimal savings would be potentially gained by reducing the utility need for verification of the non-utility injected biomethane quality. In addition, the location constraints of biogas acquisition in relative proximity to the utility transmission system would also remain.

Under the current market and regulatory conditions, there is little incentive for PG&E or other utilities to assume the additional costs, risks and responsibilities. Indeed, it may be expected that CPUC approval would be necessary for PG&E to undertake any such biogas development projects and pass on the costs to ratepayers.

**Emerging Technologies and Market**

As discussed above, the economic viability of future digester development appears currently to be primarily constrained by the comparatively low commodity prices for natural gas and electricity coupled by the relatively high costs of production. The complicated and cross resource impacts associated with dairy digester systems result in costly compliance requirements. Unless major breakthrough technological improvements are achieved, it is considered likely that manure digester production will remain economically unfeasible without government support for the foreseeable future. Furthermore, future improvements in feasibility would be expected to be minimal and incremental as long as natural gas and electrical prices remain relatively stable in real terms.

There is considerable hope within the renewable resource industry that fuel cells, “micro-scrubbers,” or other new technological improvements may be possible that could reduce unit production costs for biogas and/or biomethane production or enable affordable on-site electrical production that complies with air quality requirements.

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31 It is likely that the utility would nonetheless need to evaluate biogas quality
Similarly, the economic feasibility for biogas production is presently reduced by the currently limited market for CBM and LBM as a transportation biofuel. Major growth in commercial and/or consumer natural gas vehicles (and the necessary related fueling infrastructure) would likely represent a new market and demand for CBM and/or LBM. In which case, dairy manure production of CBM and/or LBM might be able to take advantage of some comparative advantage of local production (especially over LBM which is currently mostly imported into California at some cost either by road or rail). However, until these biofuel markets develop or other major technical advances actually occur, the economic feasibility of dairy manure digesters can be expected to remain difficult without adequate governmental and/or regulatory assistance.

**Analysis Caveats**

The previous economic assessment is based on research and interviews during a highly dynamic period for the digester and other renewable energy industries. As outlined above, there are many unknown variables facing the industry – both technological and regulatory. Consequently, quantitative analysis of the industry economics is particularly challenging and, if imbedded assumptions or factors are not recognized, any finding can be misleading or highly prone to misinterpretation.

Furthermore, most digester analyses are very site and technology-specific. In addition, most operating digester projects have been pilot or demonstration projects that have received considerable government assistance. As a result, there is extensive complexity associated with any efforts to normalize the design, costs and performance of digesters operating under very different circumstances.

Consequently, we have used a predominantly qualitative approach since the primary purpose for this economic assessment has been to provide a framework by which the key economic drivers can be distinguished from the numerous variables and other factors that have a more indirect and lesser contribution to dairy digester feasibility.

**References**


However, successful development of the proposed Clearwater and/or Port Esperanza LNG terminals in Southern California would be expected to reduce the potential locational advantage for future LBM production.
Key Factors Determining Economic Feasibility


Clear Horizons, Craven Brothers Farm Digester Project Feasibility Study, January 2006.


LaMendola, T. Personal Communication, April 2010.


Norman, Ramon, Air Quality Engineer, email to Tim Morgan at ESA, February 4, 2010.


Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>AB</td>
<td>Assemble Bill</td>
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<tr>
<td>ACEEE</td>
<td>American Council for an Energy Efficient Economy</td>
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<td>BACT</td>
<td>Best Available Control Technology</td>
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<tr>
<td>CAFO</td>
<td>Confined Animal Feeding Operations</td>
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<td>CARB</td>
<td>California Air Resources Board</td>
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<tr>
<td>CBG</td>
<td>Compressed Biomethane</td>
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<td>CCAR</td>
<td>California Climate Action Registry</td>
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<tr>
<td>CEC</td>
<td>California Energy Commission</td>
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<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
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<tr>
<td>CNG</td>
<td>Compressed Natural Gas</td>
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<tr>
<td>DG</td>
<td>Distributed Generation</td>
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<tr>
<td>ERB</td>
<td>Emerging Renewables Program</td>
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<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>IC</td>
<td>Internal Combustion</td>
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<tr>
<td>IEUA</td>
<td>Inland Empire Utilities Agency</td>
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<td>LCFS</td>
<td>California Low Carbon Fuel Standard</td>
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<td>LBM</td>
<td>Liquefied Biomethane</td>
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<td>LNG</td>
<td>Liquefied Natural Gas</td>
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<tr>
<td>MPR</td>
<td>Market Price Referent</td>
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<tr>
<td>NCRS</td>
<td>Natural Resource Conservation Service</td>
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<tr>
<td>PIER</td>
<td>Public Interest Energy Research Program</td>
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<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
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<td>ppm</td>
<td>Parts per million</td>
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<tr>
<td>PSA</td>
<td>Pressure Swing Absorption</td>
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<tr>
<td>REC</td>
<td>Renewable Energy Credits</td>
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<td>RPS</td>
<td>Renewable Portfolio Standards</td>
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<tr>
<td>TAG</td>
<td>Technical Advisory Group</td>
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<td>WDR</td>
<td>Waste Discharge Requirements</td>
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Glossary

- **Aerobic Bacteria**: Bacteria that require free elemental oxygen to sustain life.
- **Aerobic** : Requiring, or not destroyed by, the presence of free elemental oxygen.
- **AgSTAR**: A voluntary federal program that encourages the use of effective technologies to capture methane gas, generated from the decomposition of animal manure, for use as an energy resource.
- **Anaerobic** : Requiring, or not destroyed by, the absence of air or free oxygen.
- **Anaerobic Bacteria**: Bacteria that only grow in the absence of free elemental oxygen.
- **Anaerobic Lagoon**: A treatment or stabilization process that involves retention under anaerobic conditions.
- **Anaerobic** : A tank or other vessel for the decomposition of organic matter in the absence of elemental oxygen.
- **Anaerobic Digestion**: The degradation of organic matter including manure brought about through the action of microorganisms in the absence of elemental oxygen.
## Key Factors Determining Economic Feasibility

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
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<tbody>
<tr>
<td><strong>Best Management Practice (BMP)</strong></td>
<td>A practice or combination of practices found to be the most effective, practicable (including economic and institutional considerations) means of preventing or reducing the amount of pollution generated by nonpoint sources to a level compatible with water quality goals.</td>
</tr>
<tr>
<td><strong>Biogas</strong></td>
<td>Gas resulting from the decomposition of organic matter under anaerobic conditions. The principal constituents are methane and carbon dioxide.</td>
</tr>
<tr>
<td><strong>Biomass</strong></td>
<td>Plant materials and animal wastes used especially as a source of fuel.</td>
</tr>
<tr>
<td><strong>British Thermal Unit (BTU)</strong></td>
<td>The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. One cubic foot of biogas typically contains about 600 to 800 BTUs of heat energy. By comparison, one cubic foot of natural gas contains about 1,000 BTUs.</td>
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<tr>
<td><strong>Carbon Offset (Carbon Credit)</strong></td>
<td>A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” i.e. the offset provider must prove that the project would not have happened without its financial investment, and that the project goes beyond “business as usual” activity.</td>
</tr>
<tr>
<td><strong>Complete Mix Digester</strong></td>
<td>A controlled temperature, constant volume, mechanically mixed vessel designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.</td>
</tr>
<tr>
<td><strong>Composting</strong></td>
<td>The biological decomposition and stabilization of organic matter under conditions which allow the development of elevated temperatures as the result of biologically produced heat. When complete, the final product is sufficiently stable for storage and application to land without adverse environmental effects.</td>
</tr>
<tr>
<td><strong>Covered Lagoon Digester</strong></td>
<td>An anaerobic lagoon fitted with an impermeable, gas- and air-tight cover designed to capture biogas resulting from the decomposition of manure.</td>
</tr>
<tr>
<td><strong>Demand charge</strong></td>
<td>The peak kW demand during any quarter hour interval multiplied by the demand charge rate.</td>
</tr>
<tr>
<td><strong>Digestate</strong></td>
<td>The sludge or spent slurry discharged from a digester. In this report digestate generally refers to the dewatered solids portion of the spent slurry, rather than the liquid digestate, which is referred to as the effluent.</td>
</tr>
<tr>
<td><strong>Digester</strong></td>
<td>A concrete vessel used for the biological, physical, or chemical breakdown of livestock and poultry manure.</td>
</tr>
<tr>
<td><strong>Discount rate</strong></td>
<td>The interest rate used to convert future payments into present values.</td>
</tr>
<tr>
<td><strong>Down payment</strong></td>
<td>The initial amount paid at the time of purchase or construction expressed as a percent of the total initial cost.</td>
</tr>
<tr>
<td><strong>Drystack</strong></td>
<td>Solid or dry manure that is scraped from a barn, feedlane, drylot or other similar surface and stored in a pile until it can be utilized.</td>
</tr>
<tr>
<td><strong>Effluent</strong></td>
<td>The discharge from an anaerobic digester or other manure stabilization process.</td>
</tr>
<tr>
<td><strong>Energy Charge</strong></td>
<td>The energy charge rate times the total kWh of electricity used.</td>
</tr>
<tr>
<td><strong>Fats</strong></td>
<td>Any of numerous compounds of carbon, hydrogen, and oxygen that are glycerides of fatty acids, the chief constituents of plant and animal fat, and a major class of energy-rich food. “Fats are a principal source of energy in animal feeds and are excreted if not utilized.”</td>
</tr>
<tr>
<td><strong>Fixed Film Digester</strong></td>
<td>An anaerobic digester in which the microorganisms responsible for waste stabilization and biogas production are attached to some inert medium.</td>
</tr>
<tr>
<td><strong>Flushing System</strong></td>
<td>A manure collection system that collects and transports manure using water.</td>
</tr>
<tr>
<td><strong>Greenhouse Gas</strong></td>
<td>An atmospheric gas, which is transparent to incoming solar radiation but absorbs the infrared radiation emitted by the Earth’s surface. The principal greenhouse gases are carbon dioxide, methane, and CFCs.</td>
</tr>
<tr>
<td><strong>Hydraulic Retention Time (HRT)</strong></td>
<td>The average length of time any particle of manure remains in a manure treatment or storage structure. The HRT is an important design parameter for treatment lagoons, covered lagoon digesters, complete mix digesters, and plug flow digesters.</td>
</tr>
<tr>
<td><strong>Inflation Rate</strong></td>
<td>The annual rate of increase in costs or sales prices in percent.</td>
</tr>
<tr>
<td><strong>Influent</strong></td>
<td>The flow into an anaerobic digester or other manure stabilization process.</td>
</tr>
</tbody>
</table>
Internal Rate of Return  The discount rate that makes the NPV of an income stream equal to zero.

Kilowatt (kW)  One thousand watts (1.341 horsepower).

Kilowatt Hour (kWh)  A unit of work or energy equal to that expended by one kilowatt in one hour or to 3.6 million joules. A unit of work or energy equal to that expended by one kilowatt in one hour (1.341 horsepower-hours).

Lagoon  Any large holding or detention pond, usually with earthen dikes, used to contain wastewater while sedimentation and biological treatment or stabilization occur.

Land Application  Application of manure to land for reuse of the nutrients and organic matter for their fertilizer value.

Liquid Manure  Manure having a total solids content of no more than five percent.

Loading Rate  A measure of the rate of volatile solids (VS) entry into a manure management facility with methane recovery. Loading rate is often expressed as pounds of VS/1000 cubic feet.

Loan Rate  The percent of the total loan amount paid per year.

Manure  The fecal and urinary excretions of livestock and poultry.

Mesophilic  Operationally between 80°F and 100°F (27°C and 38°C).

Methane  A colorless, odorless, flammable gaseous hydrocarbon that is a product of the decomposition of organic matter. Methane is a major greenhouse gas. Methane is also the principal component of natural gas.

Minimum Treatment Volume  The minimum volume necessary for the design HRT or loading rate.

Mix Tank  A control point where manure is collected and added to water or dry manure to achieve the required solids content for a complete mix or plug flow digester.

Natural Gas  A combustible mixture of methane and other hydrocarbons used chiefly as a fuel.

Net Present Value (NPV)  The present value of all cash inflows and outflows of a project at a given discount rate over the life of the project.

NPV Payback:  The number of years it takes to pay back the capital cost of a project calculated with discounted future revenues and costs. Profitable projects will have an NPV Payback value less than or equal to the lifetime of the project.

Nutrients  A substance required for plant or animal growth. The primary nutrients required by plants are nitrogen, phosphorus, and potassium. The primary nutrients required by animals are carbohydrates, fats, and proteins.

Operating Volume  The volume of the lagoon needed to hold and treat the manure influent and the rain-evaporation volume.

Payback Years  The number of years it takes to pay back the capital cost of a project.

Plug Flow Digester  A constant volume, flow-through, controlled temperature biological treatment unit designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.

Point Source Pollution  Pollution entering a water body from a discrete conveyance such as a pipe or ditch.

Process Water  Water used in the normal operation of a livestock farm. Process water includes all sources of water that may need to be managed in the farm’s manure management system.

Proteins  Any of numerous naturally occurring extremely complex combinations of amino acids containing the elements carbon, hydrogen, nitrogen, and oxygen. Proteins are in animal feeds are utilized for growth, reproduction, and lactation and are excreted if not utilized.

Renewable Energy Credits (RECs)  Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.

Scrape System  Collection method that uses a mechanical or other device to regularly remove manure from barns, confine buildings, drylots, or other similar areas where manure is deposited.
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple Payback</td>
<td>The number of years it takes to pay back the capital cost of a project calculated without discounting future revenues or costs.</td>
</tr>
<tr>
<td>Slurry (Semi-solid) Manure</td>
<td>Manure having a total solids content between five and ten percent.</td>
</tr>
<tr>
<td>Solids Manure</td>
<td>Manure having a total solids content exceeding 10 percent.</td>
</tr>
<tr>
<td>Storage Pond</td>
<td>An earthen basin designed to store manure and wastewater until it can be utilized. Storage ponds are not designed to treat manure.</td>
</tr>
<tr>
<td>Storage Tank</td>
<td>A concrete or metal tank designed to store manure and wastewater until it can be utilized. Storage tanks are not designed to treat manure.</td>
</tr>
<tr>
<td>Straight-Line Depreciation</td>
<td>Depreciation per year equals the total facility cost divided by the years of depreciation (usually the facility lifetime).</td>
</tr>
<tr>
<td>Supplemental Heat</td>
<td>Additional heat added to complete mix and plug flow digester to maintain a constant operating temperature at which maximum biological treatment may occur.</td>
</tr>
<tr>
<td>Technical Advisory Group (TAG)</td>
<td>A working group of individual representing several California State Agencies and companies knowledgeable and interested in the Environmental Impact Report (EIR) being prepared for Dairy Manure Digester and Co-digester Facilities. The group is scheduled for four meetings and will review various background documents that will help to support the preparation of the EIR.</td>
</tr>
<tr>
<td>Thermophilic</td>
<td>Operationally between 110°F and 140°F (43°C and 60°C).</td>
</tr>
<tr>
<td>Total Solids</td>
<td>The sum of dissolved and suspended solids usually expressed as a concentration or percentage on a wet basis.</td>
</tr>
<tr>
<td>Utility Interconnection</td>
<td>The method of utilizing electricity produced from manure management facilities. Options include either (1) on farm first use then sale to utility or (2) sale to the utility then direct purchase.</td>
</tr>
<tr>
<td>Volatile Solids</td>
<td>The fraction of total solids that is comprised primarily of organic matter.</td>
</tr>
<tr>
<td>Volatilization</td>
<td>The loss of a dissolved gas, such as ammonia, from solution.</td>
</tr>
<tr>
<td>Volumetric Loading Rate</td>
<td>The rate of addition per unit of system volume per unit time. Usually expressed as pounds of volatile solids per 1,000 cubic feet per day for biogas production systems.</td>
</tr>
</tbody>
</table>
From: Brennan, Kenneth J (GT&D) [mailto:KJBh@PGE.COM]
Sent: Friday, April 30, 2010 3:33 PM
To: Nik Carlson
Subject: Dairy digester EIR

Nik:
The attached file has PG&E’s comments on the digester EIR document thus far. There may be more, but that's what I have for now. I will be largely unavailable for the next few weeks, so email is best.

<<Issues with Economic Feasibility Document.doc>>

Ken Brennan
PG&E Product Management, Senior Project Manager | Office 415-973-0017; Cell 415-531-4173; Fax 415-973-6112 | Email: kjbh@pge.com
| Address: 245 Market Street, MC N15A, San Francisco, CA 94105
**Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-digester Facilities**

**Page 2:**

**Issue:** “Local utilities represent a key potential customer for surplus energy production from dairy digesters. Local utilities are the predominant energy producers and wholesalers in the market and therefore can most effectively and efficiently manage the sale, distribution and use of digester produced energy. Currently, utilities are understandably wary of such distributed energy projects since they represent emerging competition.”

**Discussion:** This paragraph is largely inaccurate. Because of decoupling, there is no inherent reason in California for utilities to have competition issues with distributed generation (DG) projects such as digesters. In fact, PG&E has supported the development of DG through several policies, including support of the Self-Generation Incentive Program (SGIP) program, net metering and feed-in tariffs, and the work we did as the first utility in California to offer a contract for biomethane to our pipeline. Utilities must balance their support of such projects so as not to unduly shift the costs of them onto other customers, which is why we have been reticent to support increasing the amount we pay for biomethane or biogas electricity from digester projects.

**Page 5:**

**Issue:** “The California Energy Commission (CEC) conservatively estimates an average 36 cubic feet of methane per cow per day.”

**Discussion:** Estimates vary from 32 to 40 cubic feet of biogas per cow per day (not methane). Take the biogas and multiply by 60% to get methane content.

**Page 8 (fn 7):**

**Issue:** On page 8 there is a reference (fn 7) to potential T&D benefits for distributed generation biogas-fueled generation.

**Discussion:** PG&E agrees there is a potential for T&D benefits from distributed generation, but does not find that there has been any credible evidence so far that these benefits exist. In fact, given the location of dairy farms at the end of the radial distribution system, with the generator typically located near the fuel source, not the electric load of the farm, it is unlikely that T&D benefits will be found. More likely, system upgrades are required to accept the exported generation.

**Page 10:**

**Issue:** “If the sales prices for biomethane are restricted to current natural gas prices, any future production costs increases can be expected reduce the profitability of biogas production...”

**Discussion:** While the commodity price of natural gas is certainly relevant, the contract price for biomethane is determined by individual negotiation between parties. Utility gas purchase contracts are subject to approval by the CPUC.

**Issue:** “Currently, biomethane pipeline injection is only permitted into PG&E’s transmission pipelines due to insufficient and inconsistent demand within its distribution network.”

**Discussion:**
- Biomethane injection is permitted only to transmission pipelines due to distribution system end use customer demand as a limiting factor. Distribution system demand is largely dependent on summer/winter temperature fluctuations. Low demand in summer means the project will be shut-in with no market.
- SoCalGas and PG&E have different definitions of “distribution system” (250 psig versus 60 psig).
• PG&E requires injection into transmission pipes so that, in the case of scrubbing system and other protective equipment failure, our customers do not receive a slug of untreated biogas that would harm every downstream appliance or pose a serious health hazard. Transmission pipes blend that risk away.
• Not every transmission pipeline system can physically accept biomethane. If a transmission pipeline dead ends into a distribution system, that pipeline is not a likely candidate for biomethane injection.

**Issue:** “Furthermore, to meet the utilities flow requirement, any biomethane injection to the transmission pipeline must occur near urban areas that have adequate and consistent natural gas demand.”

**Discussion:** The only volumetric flow requirement that PG&E has is that the biomethane supplier meets volumes as agreed to in the negotiated operating agreement and a minimum of 120 Mcf/day so that the metering equipment can function properly. The injection point does not have to be near an urban center, but it must be made into a pipeline with consistent year-round demand.

**Page 17:**
**Issue:** “Methane has 23 times the greenhouse gas impact of an equivalent weight of carbon dioxide (CO2). Consequently, each ton of methane that is intentionally destroyed will have an equivalent GHG reduction value of approximately 23 tons of carbon dioxide.”

**Discussion:** All of the protocols mentioned attribute methane with a Global Warming Potential of 21 times CO2, not 23.

**Issue:** "A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc."

**Discussion:** In California, renewable energy and energy efficiency will not qualify as offsets. These comments should be deleted. Other examples could include "changes in manufacturing" and "destruction of high global warming gases."

**Issue:** "Flaring of collected biogas will result in a net GHG impact reduction as the more volatile methane is converted to carbon dioxide which has less than a twentieth of the climate change effect."

**Discussion:** Flaring of biogas has zero climate change effect. Cow manure generates CO2, which is needed for grass to grow. Both the US EPA and the IPCC have stated that CO2 from biological sources should not be counted. This should be reworded as "Flaring of collected biogas will result in a net GHG benefit as methane is more than 21 times as potent a global warming gas."

**Page 18:**
**Issue:** “Both the European Union (EU) and Chicago Stock Market (amongst others) operate “carbon markets” for the purchase and sale of certified carbon credits.”

**Discussion:** This should read “Both the European Union (EU) and Chicago Climate Exchange…”.

**Issue:** "Within California, the California Climate Action Registry (CCAR) has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters."

**Discussion:** Reword as "The Climate Action Reserve (CAR) has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters and has more than seven projects which are currently generating carbon credits."

**Issue:** "Between 2005 and 2007, carbon reduction credit values were as high as $50 per ton of CO2 equivalent. More recently, carbon values have been considerably lower - typically in the range of $10 per ton."
Discussion: We have never seen prices even close to $50 per ton, especially not in California. Three years ago the price was averaging $10 per ton. Right now the price is closer to $5 per ton.
Issue: "PG&E estimates a current carbon reduction price of approximately $7 per metric ton of CO2 for its Climate Smart program."
Discussion: As stated in our 2009 Annual Report for the ClimateSmart program, the average cost we have contracted for is $9.88 per metric ton.

Issue: "Additionality considers whether the GHG reduction is discretionary and whether the carbon offset purchase actually ensures carbon reductions, or whether the reductions would have occurred regardless."
Discussion: The CAR Livestock protocol language on additionality states: "The Reserve strives to support only projects that yield surplus GHG reductions, which are additional to what might have otherwise occurred. That is, the reductions are above and beyond business-as-usual – the baseline case."

Issue: “PG&E currently operates its Climate Smart program which allows participating customers to elect to pay an additional monthly premium to fund CPUC-approved projects that reduce GHG emissions. Climate Smart acquires 1.5 million tons of carbon credits annually and as such is the largest single carbon credit purchaser in California. Residential, businesses and municipal customers participating in the Climate Smart program are purchasing GHG offset credits which fund renewable energy purchases and development.”
Discussion: This paragraph must be corrected as follows:
(i) as legally trademarked, the first reference to ClimateSmart should appear as “the ClimateSmart™ program.”;
(ii) change the second sentence to “The ClimateSmart program must acquire approximately 1.36 million metric tons of verified GHG emission reductions by the end of the program’s pilot phase. Due to this requirement, the ClimateSmart program is one of the largest single purchasers of California-based voluntary offsets in the state.”
(iii) The third sentence is untrue, as ClimateSmart does not fund renewable energy projects. Change that sentence to “Residential, businesses and municipal customers participating in the ClimateSmart program are purchasing GHG offsets from environmental conservation, restoration and protection projects.”

Page 22:
Issue: This section does not even mention the cost of gas quality testing, which is a large expense of renewable gas projects.
Discussion: Gas quality costs must be paid by the project developer. These costs include: (i) initial research into untested co-digestion feedstocks and a contractor to perform such work; (ii) physical testing and verification at project start-up; and (iii) ongoing monthly physical gas quality testing. The cost of testing increases as the complexity of the feedstock increases. PG&E has already tested and may accept dairy manure-based biomethane into its pipelines. Research must be done on a per farm basis that considers variables such as the cattle feed, hormones, pharmaceuticals, and chemicals used at each dairy.

Appendix A-124
Biomethane Project Interconnection Cost Estimate (+-25%)
Estimated costs only. Not an actual cost proposal or guarantee of run rate.

<table>
<thead>
<tr>
<th>Dairy Cow Manure Projects</th>
<th>Initial Costs</th>
<th>Annual Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical Interconnection Construction</td>
<td>500,000</td>
<td>-</td>
</tr>
<tr>
<td>Gas Quality Research and Verification</td>
<td>50,000</td>
<td>140,000</td>
</tr>
<tr>
<td>Engineering Labor</td>
<td>100,000</td>
<td>-</td>
</tr>
<tr>
<td>Maintenance and Operations</td>
<td>-</td>
<td>15,000</td>
</tr>
<tr>
<td><strong>Total Dairy Manure Project Costs</strong></td>
<td><strong>650,000</strong></td>
<td><strong>155,000</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Dairy Manure with Co-Digestion **</th>
<th>Initial Costs</th>
<th>Annual Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical Interconnection Construction</td>
<td>500,000</td>
<td>-</td>
</tr>
<tr>
<td>Gas Quality Research and Verification</td>
<td>100,000</td>
<td>180,000</td>
</tr>
<tr>
<td>Engineering Labor</td>
<td>100,000</td>
<td>-</td>
</tr>
<tr>
<td>Maintenance and Operations</td>
<td>-</td>
<td>15,000</td>
</tr>
<tr>
<td><strong>Total Dairy Manure Project Costs</strong></td>
<td><strong>700,000</strong></td>
<td><strong>195,000</strong></td>
</tr>
</tbody>
</table>

**Notes:**
These costs do not include contract labor to perform initial research into untested feedstocks. The cost of such work increases with the complexity of the feedstock.

Page 27:
Issue: “Furthermore, the dairy (or third party developer) must also perform the scrubbing and compression of the biomethane as well as install and operate the metering equipment and pipeline tap.”
Discussion: The project developer is responsible for all costs of the injection project. PG&E will install and operate the metering equipment, and perform the pipeline tap.

Issue: Footnote 26 is no longer accurate. It currently states “PG&E will provide the pipeline tap and metering equipment for large suppliers (i.e. those delivering 500 M cubic feet or more per day).”
Discussion: PG&E no longer offers any incentives for pipeline injection projects.

Issue: “Recent estimates for the connection cost for biomethane injection into PG&E transmission system are $0.265 million for biomethane producers injecting less than 500,000 cubic feet per day.”
Discussion: The costs are more likely to be $400-600K depending on the size of the facilities required at the interconnection.

Issue: “Furthermore, pipeline injection use of digester biomethane will be geographically constrained due to the high cost for any pipeline or vehicle transport of the biomethane between the digester and suitable injection points which must be along the natural gas transmission system.”
Discussion: This seems to imply that biomethane can be trucked to some previously determined injection point and injected on a truck load basis. That concept is not possible from an engineering standpoint and the limitations of metering and gas quality testing equipment.

Page 30:
Issue: “The cost for biogas upgrading facilities was estimated to vary from $400,000 to over $750,000 (depending on the plant capacity).”
Discussion: That cost range is extremely low, and must be revised upward. Contact Tom Hintz of this TAG group for more accurate numbers.
Issue: “Several experts suggested that the market for future biogas would be improved if utilities such as PG&E were willing to invest, operate and maintain the necessary upgrading facilities required for pipeline injection.”

Discussion: PG&E remains very interested in facilitating the developing biomethane injection industry, and providing a market for biomethane. However, owning and operating biogas scrubbing systems is not our core utility business, and PG&E is unlikely to pursue that business at this time as third-party developers would be better suited for this work. This section should be deleted.

Issue: “…the significant production costs for pipeline injection would remain high as only minimal savings would be potentially gained by reducing the utility need for verification of the non-utility injected biomethane quality”.

Discussion: The need for gas quality testing conducted at biomethane injection points will remain unchanged.

Nick: I am out of time, please include these other comments. –Ken

Other Comments:
1. The sourcing for statements in the report is inadequate. There are frequent cites and a healthy bibliography but two weaknesses. First, a statement followed by a citation to a report should include specific page references whenever possible (most do not). Second, many statements need a source, but do not have one. A few examples: page 5 refers to a PG&E estimate that appears high and has no cite. Page 7 refers to a Dane County, Wisconsin project with no cite. Page 11 cites "(PG&E, 2009)" but there is no 2009 PG&E cite in the bibliography. Page 30 contains a long discussion of dairy production and costs with no citation.

2. The perspective of the report is pretty consistently from that of the farmer. There is nothing wrong with this, but the economic analysis of what the farmer "needs" to install biogas generation or biomethane production ignores the air quality concerns that the farmer will have to face anyway. They are discussed generally near the end, but not routinely included in the economics. Instead, the alternative to biogas or biomethane is treated as business as usual.

3. NEMBIO is not available today, but there is legislation being considered this year to reactivate that tariff and it should be mentioned in the report.

4. The discussion on page 12 of net metering is incorrect and misleading. The NEM tariff (at retail rates) is not available to biogas fueled generation. As the text correctly states, NEMBIO compensates dairy farmers at the generation component of the energy charge. The credit is capped at the total gen charges for all accounts at the dairy. The text calls the continued payment of T&D costs "considerable", but fails to point out that the T&D system is used to move the power to the other load. This comes up again on page 14 with a call for a customer to be able to meet their entire load with their own generation. Actually, they can, just not under a free-wheeling arrangement. The customer does get retail credit for simultaneous load at the generator. Finally, AB 920 is cited as an improvement for dairy farmers. AB 920 applies only to customer on NEM (solar and wind).

5. Footnote 15 on page 13 should include the fact that the reverse auction tariff is only being considered for renewable power up to 10 MW.

6. The SGIP program was expanded via SB 412 last year beyond fuel cells and wind. It is highly likely that biogas digesters could qualify.

7. The discussion on page 24 about "outside California" was hard to follow. If the only thing making national economics not work in California are the NOx emissions, then I got the point. If there was something else, we missed it entirely. Again a need for clarity.
8. Table 2 on page 29 has a couple of typos. The unit under Annual Energy Production should be MWh, not kWh, or else these examples are extremely inefficient. The unit under Capital Cost should be $/kW, not $/kWh.

9. The Role of Utilities: the report merely cites utilities’ wariness of distributed generation systems, with no substantial discussion on this specific technology and specific programs utilities have to accommodate DG. Moreover, even if the former was the case, the report ignores utilities’ increasing appetite for biogas (as a result of RPS requirements, and the value of biogas as unique, base-load renewable resource), and does not provide much detail on the ability to use digester-biogas off-site, thereby (1) avoiding the air issues associated with on-site generation and (2) utilizing the efficiencies associated with a large-scale power plant.

10. Potential Environmental Impacts Evaluation Report (CEQA analysis): The report seems to address a “green field” scenario in which the digester site is developed from scratch, with the resulting negative environmental impacts. However, in most cases, the digesters are incremental to existing dairy sites, which activities sometimes involve the creation of a plume (which carries severe environmental consequences, including methane emissions, odor, water pollution, insect-transmitted diseases and nuisances etc). Digesters largely eliminate the plume and thereby should be considered on a net cost-benefit analysis, i.e. a “brown field” development.

11. The report does not mention any industry accumulated experience in the operation (production consistency, O&M) of the technologies referenced, even though there are a number of operating facilities in California, Idaho, Wisconsin, and many more in Europe.
Hi Paul,

Here is the email and attachment I have from Mr. Lehr on April 30. He also sent an email/attachment on May 3. Please let me know if you would like me to forward that email as well.

-Jennifer

---

From: Jackson Lehr [mailto:jlehr@calbioenergy.com]
Sent: Friday, April 30, 2010 6:10 PM
To: Jennifer Tencati
Cc: nblack@calbioenergy.com; 'N Ross Buckenham'
Subject: Re: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Jennifer,

Please find attached a markup of the document with suggestions from the California Bioenergy (CalBio) team. The document was already very impressive in its original form, and we hope our suggestions will help provide some additional facts to make the document as accurate as possible and to highlight some of the most pressing barriers to widespread digester development (which ultimately is a question of economic viability, the very subject of this document).

We would be happy to make ourselves available next week if Nik has any questions or would like to discuss any of our suggestions.

Thank you for all of your help with the TAG efforts.

Have a nice weekend!

Best wishes,

Jackson

---

On 4/27/10 3:33 PM, "Jennifer Tencati" <j.tencati@circlepoint.com> wrote:

Hi Ross,

Thank you for taking the time to review the document and develop comments. Please send the comments to me and I will make sure that the appropriate team members receive a copy. We are asking for comments by the end of the week – sounds like that is in line with your timing.

8/23/2010
Nik Carlson, ESA, is the lead for this document. If you could please provide a few day/time options that you would be available to review your comments (early next week), I would be happy to coordinate a call with Nik and other team members that should be included.

-Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com <mailto:j.tencati@circlepoint.com>
916.658.0180 x131

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Please think of the environment before you print this email

From: N Ross Buckenham [mailto:rbuckenham@calbioenergy.com]
Sent: Monday, April 26, 2010 9:13 AM
To: Jennifer Tencati
Cc: jlehr@calbioenergy.com; nblack@calbioenergy.com
Subject: RE: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Jennifer

Thanks very much for sending this document.

We will listen into the CPUC meeting and their comments this AM and then work on our comments hopefully completing this week. Is that time frame ok with you?

Who is the author of this document and could we do a walk through over the phone of our comments with him/her?

Regards

Ross

N. Ross Buckenham
California Bioenergy, LLC
office: 214-849-9886
mobile: 214-906-9359

8/23/2010
Hi Ross,

Attached is a Word document version. If you don’t mind, we ask that you not distribute this version, but are happy to share it with you to help facilitate capturing your edits. Please let me know if you have any questions.

-Jennifer

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N. Ross Buckenham  
California Bioenergy, LLC  
office: 214-849-9886  
mobile: 214-906-9359

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Dear TAG members,

In follow up to our third TAG meeting today, we have arranged for a call in number for the 10:30 a.m. call on Monday, April 26th to discuss the Administrative Draft Economic Feasibility report (attached).

The call in number is: (605) 475-4900  
ID number: 501775#

You may also join the meeting in person. It will be held at CPUC’s San Francisco office at 505 Van Ness Avenue in the Golden Gate Room. You may enter the building on Golden Gate Avenue, next to the ATM machine and go directly to the Golden Gate Room. Parking is available on the street (metered) or at a lot on Golden Gate and Franklin (Franklin is a one way street) or Opera Plaza across from CPUC.

If you need to contact CPUC in the morning, please call Eugene Cadenasso at (415) 703-1214.

If you have questions or comments about the report or other elements of the project, please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x131.

-Jennifer
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Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-digester Facilities

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Executive Summary

Extensive research and review was conducted on published industry analyses on anaerobic digestion and the use of dairy manure for bioenergy within California and elsewhere within the United States. Numerous factors are identified as key contributors influencing the future economic viability of the potential development of dairy manure digesters and co-digesters within the Central Valley. The factors determined to be important economic drivers (both positive and negative) are summarized below:

- **Conventional Energy Prices.** Most fundamentally, current and projected future commodity prices of natural gas and electricity are critical underlying revenue constraints for dairy digesters. In terms of its physical uses, natural gas is a readily available substitute for dairy digester produced biogas and biomethane. Consequently, most potential customers will be unlikely to buy biogas or biomethane at prices much above their commodity price for natural gas. Similarly, the value of biogas generated electricity will be limited by the prices of electricity from comparable conventional sources. Currently, long-term natural gas prices are not forecast to increase materially (adjusted for inflation) due to recent discoveries of new domestic shale gas reserves. And although electricity prices in California may increase at a rate faster than inflation, the causes of the projected increase are primarily associated with the RPS. Consequently, contrary to conventional wisdom a few years ago, biogas cannot expect substantially improved feasibility from market-driven future commodity price escalation.

- **Regulatory and Legislative Support.** One form of regulatory support is the California Renewables Portfolio Standard (RPS), which helps to distinguish the value of digester-based methane and electricity from that of their conventional-counterpart commodities. A form of legislative support is Senate Bill (SB) 32, the implementation of which has the potential to increase the price of and improve the existing feed-in-tariff (FIT) for small renewable generation. The price of the FIT is currently set at the Market Price Referent (MPR), a benchmark price that is primarily tied to the price of natural gas (and may therefore be inappropriate for setting renewable energy pricing), and does not include the full value of electricity from biogas (e.g., renewable energy credits (RECs) that help achieve the RPS). Additional forms of public sector support include Federal and state grant funding, low interest loans, tax incentives, and pilot programs, all of which have played a vital role in past digester development (though there are currently digesters in operation on fewer than 20 out of California’s approximately 1,900 dairy farms).
the amount and form of future public sector support, especially that which improves
electricity prices for small renewable generation, can have a strong positive role in, and is
expected to remain essential for, the continued development of manure digester systems.

- **Air Quality Regulation of On-site Electrical Generation.** On-site generation of electricity
  represents a potential direct, “lower tech” and inexpensive beneficial use option for biogas.
  However, air quality restrictions within the Central Valley may preclude this use. If cost
effective compliance technologies or mitigation can be developed, digester systems could
be greatly enhanced – especially if adequate feed-in tariffs or other utility support increases
the revenue potential for small scale distributed energy production.

- **Access to Capital and Third Party Developers.** The current financial difficulties facing
most dairy farmers and the generally tight credit market will ensure that funding for digester
developments will be scarce and costly for the foreseeable future. While increased participation
by third party developers may provide some technical and financial assistance, private capital
will be relatively costly. The potential “capital crunch” constraints will be especially acute
for those projects that require major construction, involve new technical applications
and/or supply energy to less established and developing non-utility markets. With
sufficient prices and contracting mechanisms, third-party developers could play a key
role in widespread digester deployment, creating standardized development processes and
ongoing operations, enabling capital efficiency and cost reductions, and making it easier
for dairies to host digester electricity and biomethane projects. [[SUGGEST MOVING
THIS UP TO BECOME BULLET #4]]

- **Cost and Minimum Efficient Scale of Biogas Upgrading.** Biogas scrubbing and
conditioning for biomethane production is currently costly and can only be cost
effectively performed at production levels significantly greater than most individual dairy
operations can support. Combined with biogas upgrade system costs, system design,
methane losses (during upgrading), parasitic loads (from compression), and geographic
constraints (most dairies are not close enough to a gas transmission pipeline) represent
key factors limiting the feasibility of widespread deployment of biomethane facilities for the
foreseeable future.

- **Role of Utilities.** Local utilities represent a key potential customer for surplus energy
production from dairy digesters, and are also essential participants enabling digester-
based energy to access natural gas pipelines and the electrical grid. Significantly
streamlined, and potentially financially supported, interconnection procedures for
digester-based gas and electricity would increase the economic feasibility of dairy
digesters. For electric projects, utilities are currently supposed to follow a FERC Fast
Track process, but seem to be following a more complex “Section 3 Study Process”
which can take more than a year and add significant costs. Utilities also face regulatory
restrictions that can affect both their involvement and, most importantly, the prices that
they can pay for dairy digester energy. Nevertheless, innovative and constructive
partnerships between digesters and utilities offer a key potential mechanism for greater
and more cost-effective development of biogas as a renewable resource. [[SUGGEST MOVING
THIS UP TO BECOME BULLET #3]]

- **Technological Change.** Although many of the core digester and biomethane technologies
are fairly well established, future commercialization of dairy manure digester systems
may be expected to result in some cost effectiveness improvements. However, currently most
foreseeable improvements appear to be incremental rather than fundamental.
Consequently, most analysts suggest that per unit production costs for biomethane and
related electrical generation will remain higher than commodity energy prices and hence
public support for production will remain necessary. Key technology breakthroughs that
could dramatically improve future dairy digester profitability include cost-effective on-site

**Deleted:** Public Sector Support.
Federal and state grant funding, low
interest loans and other public sector
support (e.g., tax incentives and pilot
programs) have played a vital role in past
digester development. Both the amount
and form of future public sector support
can have a strong positive role in
fostering manure digester implementation
within the Central Valley. Future
government support is expected to remain
essential for continued development of
manure digester systems.

**Deleted:** Biomethane production
**Deleted:** for Biomethane Production

**Deleted:** Local utilities are the
predominant energy producers and
wholesalers in the market and therefore
can most effectively and efficiently
manage the sale, distribution and use of
digester produced energy. Currently,
utilities are understandably wary of such
distributed energy projects since they
represent emerging competition. In
general, the administration of small scale
production (from dairy digesters)
provides limited financial return for
utilities.

**Deleted:** limit
**Deleted:** However
electrical generation with biogas (e.g., very low emission controlled internal combustion engines, micro-turbines or fuel cells) or inexpensive, efficient and/or farm sized biogas upgrading systems with low-pressure distribution line injection.

- **Proximity to Feedstocks and Energy Infrastructure.** The location of potential dairy digester and co-digester systems can be critical to the facility’s ability to obtain sufficient manure (and possibility feedstocks for co-digesters) and/or supply its biogas and other facility products to potential buyers at an attractive price.

- **Permitting.** Facility development design and permit costs to comply with state and local regulations can represent major delays, risks and financial expenses that may discourage potential digester development. The Program EIR has the potential to significantly reduce the delays and costs of digester projects if a streamlined process (similar to the 30-day process available for Tier 1 systems for new lagoons) can be developed for digester projects that make improvements to a dairy’s existing manure management system (e.g., by constructing a single-lined covered lagoon digester on a dairy that does not already have any lined storage lagoons, or by covering an existing lagoon without making any substantial changes to it) and do not substantially change the nature of the discharge (i.e. for manure digestion only).

Many other factors will also contribute to the profitability of dairy digester systems. For example, many analyses have investigated the potential for revenues gains from digester byproducts (e.g., digestate sales), tipping fees (for co-digesters), or the environmental attributes of anaerobic digesters (e.g., carbon offsets) as important feasibility factors. However, the magnitude of these revenues will **likely** remain secondary to the value of the digester’s primary product, which is biogas. One notable exception is the potential for the implementation of Assembly Bill (AB) 32 and/or a Federal cap-and-trade system to create a compliance market in which the carbon offsets from dairy digesters could be sufficiently valuable to create a revenue stream on the same order of magnitude as the biomethane or electricity revenue stream.

**Introduction**

The technological feasibility of biogas production from manure digesters and co-digesters is well established. Generally, digester produced biogas has been used for on-site generation of electricity and/or heating to meet the farm’s needs. Farm digester systems typically can produce three or four times the amount of energy that their farms need. This surplus biogas production represents a significant renewable energy resource with considerable potential economic value and environmental benefits.

However, to understand and evaluate the economic and environmental trade-offs associated with future manure digester and co-digester systems in the Central Valley of California, the key factors determining the economic feasibility need to be determined. Three basic types of economic factors can be identified: revenue factors, cost factors and implementation/development issues.

The balance and interrelationships of these factors under the specific project circumstances will determine the project’s overall feasibility. Most simply stated, if the average revenues (i.e., on a per unit basis) are greater than the digester’s average cost of production, then the project will have a positive benefit-cost ratio and will, in a basic sense, be economically feasible. However, to fully
assess the project’s feasibility, implementation factors should also be considered to determine the likelihood that successful future development can occur.

Revenue and costs naturally face tradeoffs in the project’s feasibility as increased costs are usually necessary to generate higher revenues. The key for improving a project’s feasibility occurs when the marginal revenues are greater than the marginal cost required for the revenue growth.

Each factor will have both technical and financial components determining the magnitude and nature of its effect on the system’s feasibility. Generally, economies of scale associated with greater production efficiencies will result in a lower production cost per unit. Similarly, at a fixed rate of production, higher sale revenues (or reduced production costs) will increase the revenues per unit. In both cases, the system’s economic feasibility will be improved.

The following analysis provides a brief description of the key factors affecting the economic feasibility of digester systems. The nature and extent of each factor’s contribution or role to the economic feasibility is also identified and evaluated. The central purpose of the analysis is to identify those economic or technological “drivers” that play a major role in determining the viability of digester system development. Expected future trends that might alter the system’s overall economic feasibility are discussed.

The analysis generally discusses manure digesters and unless explicitly noted otherwise, should be read as also applicable to and inclusive of co-digester systems. In addition the report maintains an important distinction between biogas and biomethane. Biogas is generally synonymous with raw biogas, i.e., the unrefined biogas produced by anaerobic digesters that has a methane content of 50% (plug flow and tank digesters) to 70% (covered lagoons). Biomethane refers to refined biogas with higher methane content, typically 99 percent (PG&E).

Finally, it should be noted that this analysis primarily addresses “economic” feasibility issues and as such considers the general costs and benefits of manure digesters. Strictly speaking, “financial” feasibility analysis typically refers to a more specific and comprehensive determination of the revenues and expenditures for a well-defined and site specified project. As such, a financial feasibility analysis would typically provide a more detailed description and estimates of project costs and revenues, consider its business cash-flow and include greater characterization of applicable market conditions and other considerations – primarily from the perspective of the potential owner/investor. Nonetheless, financial and economic factors are often used interchangeably. Unless specified otherwise, references to financial issues will refer to a more general economic assessment of cost and revenue issues.

The economic feasibility for specific systems will depend not only on general feasibility factors but may also depend upon site- or system-specific considerations. Nonetheless, important general observations can be identified and assessed.

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1 Except in cases where equipment of facility requirements or cost / revenue thresholds may result in a “step-function” cost.
Revenue Factors

The revenues generated by a future digester are central for its economic viability. Typically, it is more difficult to estimate future revenues than it is to estimate future costs which are easier to specify. This is particularly true in the case of a new or emerging market (e.g., such as biomethane) where the potential customers and future product applications are difficult to identify and fully evaluate.

The following section provides a brief overview and assessment of the various factors that will influence the potential revenue performance of future anaerobic digester development in the Central Valley of California. When possible, the relative magnitude and any significant future revenue variables are also reported so that those factors that are current and future revenue “drivers” can be identified and their inter-relationships with cost and implementation better understood.

Biogas Productivity

The efficiency and effectiveness of biogas / biomethane production of manure digesters and other related production processes is a central factor in determining economic feasibility. All else being equal, greater biogas production will increase the system’s revenue potential and hence cost-effectiveness.

Currently, most dairy digester produced biogas is used on-site for energy generation. Electrical production is generally the primary use of the produced biogas although heat is frequently also produced for use in the anaerobic digester either as part of a combined heat and power system (CHP) or separate dedicated boiler systems. Consequently many of the feasibility studies for manure digesters report their productivity and costs in terms of the system’s electricity production.

Overall System-wide Estimates

There is a wide variance in the methane and electrical production rates estimated for manure power systems. The potential biogas production will not only depend on the anaerobic digestion process used but also on both the volume of biodegradable organic materials in the collected manure and the length and type of manure collection and storage used. Similarly, the amount of electricity that can be produced by the digester system will also depend on the electrical generation system used.

The California Energy Commission (CEC) conservatively estimates an average 36 cu.ft. of methane per cow per day (with an energy content of 36,000 Btu/day) which can generate 0.107 kW of electricity. The EPA estimates that manure digesters can typically produce 38.5 cu.ft. of methane per cow per day (EPA, 2004).

Actual daily electrical generation performance at Hilarides Dairy was substantially less at 0.055 kW per cow (though partly due to substantial biogas flaring during the evaluation period) (WURD, 2006). Craven Farms reported achieving daily energy values of 34,500 Btu/cow with a 0.096 kW.

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2 The thermal energy recovered in a CHP system can be used for heating or cooling farm facilities. Since CHP captures the heat that would otherwise be lost in traditional electrical generation, the efficiency of an integrated system is much greater (up to 85%) than the separate systems combined efficiency (45%) (ACEEE, 2010).

3 Whenever possible, production and cost projections have been normalized for a 1,000 lb dairy cow.
kW per cow electricity generation rate that is comparable to CEC estimates. Other studies suggest 0.14 kW per cow (Electrigaz, 2008), and 0.1 kW per cow (Black & Veatch, 2007) as reasonable daily electrical productivity projections. Other analysts have more optimistic estimates of the per cow energy values. PG&E has estimated that each cow may generate 1,640 kWh annually (equivalent to 0.187 kW per cow).

Within these biogas production parameters, it is generally agreed that adequate biogas capacity can be attained by larger dairies for development of dairy digesters to be technically feasible, and to be potentially economically viable with sufficient revenue assistance.

Specific Digester Systems

Manure Digesters

Three primary anaerobic digester system approaches are commonly used to treat dairy manure. The system most suited for a specific dairy operation will generally depend on its manure management system. As of October 2009, 21 major anaerobic digester systems had been constructed and are currently operating within California. The digester systems vary from relatively small dairy farm facilities processing the manure wastes for approximately 200 head of cattle to very large dairies with up to 5,000 cattle.

- **Covered lagoon systems** are the most basic and traditionally the most inexpensive anaerobic digester systems to construct and operate. These systems take advantage of the highly diluted (typically with a 3% or less total solid content) “flush” manure handling systems employed by most California dairies to produce a high BTU (70% methane) fuel. Covered lagoon digesters generally are unheated (mesophilic) and are well suited for co-digestion of whey, vegetable washing wastes and similar agricultural co-digestates (Gallo Farms) but may not be well suited for co-digestion with heavier more concentrated industrial waste feedstocks (e.g. grease). The average retention times for processing the manure is 45 to 60 days. The biogas conversion rates for covered lagoon systems are generally 35% to 45% (Burke, 2001). Covered lagoon systems are currently the most widely constructed and operated dairy digester systems in California.

- **Complete mix systems** consist of a tank constructed of either reinforced concrete or steel. The digester contents are periodically mixed and frequently heated to maintain an optimal temperature for methane production. As a result, complete mix systems are more expensive to construct and require applied energy to operate. These systems work best with slurry manure with a total solids content of 3% to 10%. As a result they can be used by managed flush manure management dairies or scrape manure dairies if water can be added to the collected manure. Complete mix systems are well suited for co-digestion and have a relatively short retention time of 15 to 20 days. Consequently they are also able to handle higher processing loads. Heated digestion (thermophilic) with a complete mix system can be expected to increase biogas conversion rates to 45% to 55% (Burke, 2001). Currently, only a few complete mix digester systems are operating within California.

- **Plug Flow Digesters** consist of a long relatively narrow tank often built below ground. The digester requires semi-solid manure (i.e., with a total solid content between 11% and 13%) consistent with “scrape” manure management systems. Plug flow systems can be

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4 In 2009 six operating digester systems have recently suspended or closed their operations due to financial difficulties or regulatory compliance issues.
operated heated or unheated. The costs and biogas conversion rates for plug flow digesters are comparable to similar complete mix systems. Typical retention time for plug flow digesters are 20 to 30 days (Burke, 2001). Also, plug flow digesters are less well suited for co-digestion use. Currently, 6 plug flow digesters currently operate or recently operated within California.

Until recently, the price performance of these three digester systems were roughly comparable. The higher biogas production from managed digester systems (i.e., complete mix and plug flow) covered the additional construction costs. As a result, when adjusted for biogas production, the costs per cow for these systems were approximately the same (Martin, 2010). However, as result of recent imposed manure management regulations for Central Valley dairy farms, depending on their land and groundwater conditions, many farmers are required to construct more expensive Tier 1 lagoon systems. In such cases, the added costs for double lining or reinforcing the lagoons represent a significant additional cost and could make complete mix and plug flow systems more attractive and cost-effective digester systems for biogas production, depending on the manure-management practices of the dairy, which remains an important factor in choosing a digester system.

Wider adoption and commercialization of digester systems may be expected to reduce system costs and improve performance – both from facility design improvements and better system management. However, the biogas productivity improvements will likely be relatively limited and incremental.

**Co-digesters**

The biogas productivity of dairy manure digesters can be greatly increased by the addition of other non-manure organic feedstocks. The proportional increase in biogas production will depend on the quality and suitability of the added feedstock. Food or agricultural wastes with higher oil or grease contents will generally release a greater amount of methane than other feedstocks with lower potential energy values. There is considerable variation amongst analyses in the amount of additional methane that co-digesters can produce. A conservative analysis for the CEC observed approximately a 35% improvement in methane production by co-digestion (CH2M Hill, 2007). Other commenters suggest that high energy feedstocks (e.g., fats, oils and greases or municipal organic wastes) could result in a doubling or even tripling of biogas production by dairy digesters (Hintz, 2010). Such industry analysts projected that the potential for major gas productivity improvements (supplemented by tipping fee revenues with longer term contracts for handling the municipal green wastes) will make a substantial improvement in the economic feasibility of biogas production (Best, 2010).

Co-digestion is more management intensive and could add greater reporting and oversight requirements to comply with water quality and solid waste regulations. However, the additional equipment costs for enhanced production should be minor (presuming the feedstock handling, preparation
and storage requirements are limited). Consequently, many analysts suggest that co-digestion can provide cost effective biogas production gains.

However, availability of suitable feedstock will be important for determining the practicality and cost effectiveness of co-digestion. Many analyses identify potential tipping fee revenues for the digester operator from the feedstock sources as an important additional revenues source. However, as discussed later under the discussion of by-product revenues, most potential agricultural wastes are only seasonally available and may be located too far from specific digesters to be cost-effectively transported. Feedstocks also may become a commodity so that co-digester operators will likely have to obtain a variety of different feedstocks.

**Centralized Digester**

Only a few studies have assessed the economic feasibility of centralized digesters within the United States. Feasibility studies for centralized digester systems in New York state, southern Wisconsin and Oregon concluded that the proposed systems were uneconomical (Bothi, 2005; Reindl, 2006; DeVore, 2006). Analysis for a centralized manure digester in Dane County, Wisconsin projected significant cost efficiencies compared to individual systems but still required major public and private sector support.

A few large centralized manure digesters have been constructed and operate in the United States. The Inland Empire Utilities Agency’s (IEUA) Chino Basin project in South California was the first centralized anaerobic digester to be developed in the United States and is the only centralized digester facility currently operating in California. The IEUA project came online in 2002 and processes 225 tons of manure per day from 6,250 dairy cows, plus food waste from local food industries. The manure is trucked to the facility from six farms located within 6 miles of the digester (Davis, 2009).

However, currently all of these centralized digesters are in effect demonstration projects having received major funding assistance and have faced significant operational difficulties. The Chino Basin facility itself received approximately $5 million of its $8.5 million construction cost from the USDA’s Natural Resource Conservation Service (NCRS) for watershed protection. The CEC provided approximately $2 million in funding with the remainder provided by the Inland Empire Utilities Agency (IEUA) that owns and operates the facility. The energy generated from the biogas powers the agency’s off-site groundwater desalinization plant and wastewater facilities.

Large scale biomethane production requirements are a primary rationale for centralized digester systems. Although there are potential limited economies of scale for the centralized digester, manure transportation and handling costs can offset the economic savings if there are not sufficient suitable dairies willing to participate in close proximity to the proposed facility. Given geographical constraints on the economies of scale, centralized digester systems represent a secondary factor for digesters’ economic feasibility. Currently, there are only limited future system enhancements foreseen that would improve their cost-effectiveness.

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5 It is presumed that co-digestion will not substantially alter the value or use of the resulting digestate except for the negative aspects from potential net nitrate and salt increases associated with the feedstock importation to the dairy.
Electrical Generation

Electrical generation is currently the primary use of digester biogas within California. Biogas (and biomethane) can be used to generate electricity using a variety of technologies including reciprocating engines (e.g., such as internal combustion), microturbines, gas turbine and fuel cells. Electrical generation with digester gas represents a promising distributed generation (DG) technology offering not only the environmental benefits of offsetting fossil fuel use but also has the additional benefit of destroying methane which otherwise would have major greenhouse gas impacts.

 Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. This emission standard has been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards.

Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, currently properly operated “clean burn” IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations (Joblin, 2010). While additional selective catalytic reduction can in some cases be used to further reduce emissions, the necessary secondary emission controls are expensive and difficult to operate on lower energy fuels such as unrefined biogas. Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 - 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the SCS-Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010).

Microturbines are a newer technology that is becoming increasingly available. While potentially well suited for low emission electrical generation using biomethane, microturbines generally require relatively consistent operating conditions, do not operate well under hot climate conditions (e.g., such as during summer months within the Central Valley) and are sensitive to the effects of hydrogen sulfide impurities present in the biogas. Recent implementation efforts at dairy digesters have been mostly unsuccessful as reliability issues could not be solved for on-farm uses (Dusault, 2010). Analysts also suggest that at comparable implementation scales, the thermal conversion efficiency of microturbines will typically be 5% less than internal combustion (IC) engines.

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6 Only Vintage Dairy facility near Fresno uses the majority of its biogas production for biomethane production and injection into the utility grid.
7 Distributed generation also potentially offers additional system benefits of reduced transmission line infrastructure requirements and possibly reduced peak power system capacity requirements.
9 The reduced efficiency rates for biogas electrical generation compared to natural gas reflect the biogas’s lower methane and higher impurities content.
TABLE 1
COMPARISON OF ELECTRICAL GENERATION TECHNOLOGIES FOR BIOMETHANE

<table>
<thead>
<tr>
<th>Factors</th>
<th>Microturbines</th>
<th>Combustion Turbines</th>
<th>Reciprocating Engines</th>
<th>Fuel Cell</th>
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<tr>
<td>Cost ($/kW)</td>
<td>$300 - $1,000 / kW</td>
<td>$300 - $1,000 / kW</td>
<td>$300 - $900 / kW</td>
<td>$5,500 - $12,000 / kW</td>
</tr>
<tr>
<td>Commercially Available</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Only Phosphoric Acid Fuels Cells Available</td>
</tr>
<tr>
<td>Size Range</td>
<td>30-500 kW</td>
<td>500 kW – 25 MW</td>
<td>5 kW – 7 MW</td>
<td>1 kW – 10 MW</td>
</tr>
<tr>
<td>Efficiency</td>
<td>20 – 30%</td>
<td>20 – 45% (at scale)</td>
<td>25 – 45%</td>
<td>30 – 60%</td>
</tr>
<tr>
<td>Emissions</td>
<td>Low (&lt;9 – 50 ppm) NOx</td>
<td>Very Low when controls applied</td>
<td>Emission Controls Necessary for NOx CO – 50 ppm min.</td>
<td>Nearly zero</td>
</tr>
<tr>
<td>CHP Possible</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Commercial Status</td>
<td>Small Volume Production</td>
<td>Widely Available</td>
<td>Widely Available</td>
<td>Only Phosphoric Acid Fuels Cells Available</td>
</tr>
</tbody>
</table>

All dollar amounts in 2007 dollars.
SOURCE: California Energy Commission; ESA.

Combustion turbine engines are a mature technology but scale issues for their implementation preclude their use with dairy digesters except for the relative large or centralized community systems. At the lowest end of the scale, at least 5,000 dairy cows would likely be necessary to generate sufficient biogas production. The conversion efficiencies for combustion turbines are also expected to be reduced at the scales likely to be applicable for any on-site or community systems.

Fuel cell technology is currently at an early stage of development and consequently the costs for fuel cells are many times greater than for comparably sized micro-turbine, turbine or IC engines. Even though the efficiency of fuel cells are considerably better than the other technologies, given this very large production cost differential, until major technological improvements and/or large scale commercialization is achieved, fuel cells will remain dramatically less cost-effective for implementation.

EPA estimates that that the maximum thermal conversion efficiency of biogas to electricity by a standard reciprocating engine (internal combustion) is 28.5%. However, due to the difficulty in sizing engine-generator sets for optimal efficiency as well as a likely on-line operating rate of 90%, electrical output for biogas is estimated to be 66.6 kWh / 1,000 cu.ft. of methane. Other analysts recommend that realistically, the thermal efficiency conversion to electricity is between 18% and 25%. Modern lean-burn reciprocating engines are delivering 32% efficiency with biogas or 90 kWh / 1,000 cu.ft. of biomethane. One company has developed a reciprocating engine custom designed for biogas, which is able to run at high efficiencies and ultra-low emissions without the use of operationally intensive and costly after-treatment.

Electrical production with biogas will remain an important potential alternative use for digester systems. Consequently, the electrical generation productivity will have a direct revenue effect by determining the amount of energy that can be sold or used from the system. But, as discussed below, other factors such as pricing structures with local utilities will have a greater influence on the system’s overall economic feasibility than its electrical generation performance. However, it is
possible that major technological advances could provide major improvement in the cost-effectiveness and/or environmental performance of future biogas electrical generation systems.

**Commodity Prices of Energy**

**Natural Gas**

Generally speaking, biomethane is a more valuable energy commodity to utilities than biogas generated electricity since the biomethane can be more readily stored for later use. Consequently, it is easier for utilities to use the biomethane as an energy resource during periods of higher energy demand (i.e., when its value as an energy resource will be higher).

In a fundamental way, the commodity price of natural gas constrains the economic value and sale price for digester system produced biogas and biomethane. Natural gas is a substitute energy alternative for on-site biogas use, off-site commercial sale or upgrading to biomethane. If the renewable and environmental attributes of the produced biomethane are considered separately (i.e., Renewable Energy Credits [RECs] and greenhouse gas [GHG] credits), then the core value of biomethane will be largely limited to the substitution cost for potential purchasers (e.g., such as industrial users or utility) to use natural gas to meet their energy needs.

In past years, the price of natural gas has fluctuated greatly. The price variability had been partly due to the major international oil price fluctuations and global economic instability. Current natural gas prices are approximately $5.40 /1,000 cu.ft.\(^\text{10}\) Extensive future supplies of domestic natural gas are currently believed to be available and ongoing technological improvements in natural gas recovery are expected to enable natural gas production to increase over the next 25 years. During that period, natural gas prices are expected to remain unchanged in real terms (USEIA, 2010).

While long term stable natural gas prices (in real terms) are good for the general economy, the absence of any significant future natural gas commodity price increase will undercut the future economic feasibility of biomethane production. If the sales prices for biomethane are restricted to current natural gas prices, any future production costs increases (in real terms) can be expected reduce the profitability of biogas production unless offsetting technological improvements are achieved.

Currently, biomethane pipeline injection is only permitted into PG&E’s transmission pipelines due to insufficient and inconsistent demand within its distribution network. Furthermore, to meet the utility’s flow requirement, any biomethane injection to the transmission pipeline must occur near urban areas that have adequate and consistent natural gas demand.

An initial pilot project at the Vintage Dairy near Fresno is currently operating and processes manure from approximately 3,000 cows into biomethane (important to note that this project has ceased operations due to financial difficulties, assuming that is correct). The dairy has successfully upgraded its biogas to meet PG&E’s gas quality requirements. Vintage Dairy is located along a natural gas transmission line and therefore is able to inject on-site. In PG&E’s experience, biogas

\(^{10}\) City Gate Price for November 2009 (U.S.E.I.A, 2010).
injection projects more than 4 to 5 miles from a transmission pipeline are less economically viable (PG&E, 2009). Other studies and analysts have also concluded that proximity to interconnection locations are a major limiting constraint for the feasibility of biomethane pipeline injection (Goodman, 2010). Consequently, the existing natural gas transmission system infrastructure is considered a key feasibility constraint for future development of any dairy biomethane pipeline injection within the Central Valley.

Biomethane could potentially be piped to local industry or commercial customers with sufficient energy needs. Again however, due to the relatively high cost of construction for delivery pipelines, proximity to the biomethane production facility will be a key feasibility constraint. Furthermore there are likely to be only a limited number of industrial or commercial users with adequate power demand.11

Alternatively, biomethane can be compressed or liquefied for truck transportation and/or transportation fuel use. The biogas conditioning requirements for compression biomethane (CBM) or liquefied (LBM) are comparable to those required for pipeline quality biomethane although specific users or fuel use may be accept higher carbon dioxide levels.12 As is discussed in the assessment of production costs, the purified biomethane must not only be compressed or liquefied, but on-site storage is also likely to be necessary until it can be truck transported to its end customers. Given their very similar chemical composition, the market prices for compressed CBM and LBM are expected to be highly comparable to compressed natural gas (CNG) and liquefied natural gas (LNG) prices.13

The commercial sales potential for CNG and LNG are currently relatively limited. However, CNG offers substantial fuel cost savings as prices are currently averaging approximately $2.25 per gallon gasoline equivalent compared to diesel’s current $2.70 per gallon gasoline equivalent (cngprices.com 2010; CEC, 2010). The current market is primarily focused on sales as a “clean” transportation fuel for vehicle fleets. While municipal or government agencies have been major initial adopters of CNG vehicles, private companies are also considered potential customers. Presently, the main operational limits to CNG powered vehicles use is their horsepower constraints which make them less well suited for trucking use over major gradients. The greatest market demand for CNG fuel is within California’s major urban areas where the negative air quality effects of diesel trucks are highest and the CNG supply infrastructure can be most cost effectively developed.

Although, there are existing and future sales opportunities for CBM and LBM, it remains an emerging market that is constrained by the higher cost of conversion or purchase of CNG/LNG powered vehicles and the need for expansion of the fueling infrastructure. Consequently, the value of both

11 Under some circumstance and pending local air quality issues, it may be viable for “raw” biogas to be used for industrial or commercial heating systems. In which cases, if the relatively costly biogas upgrading are avoided, it could be economically viable to pipe the biogas further distances to commercial customers.

12 Acceptance of higher carbon dioxide proportion will offer some production cost savings.

13 If the biomethane’s environmental attributes (e.g., renewable energy credits [RECs]) are valued separately. Given the nascent CBG and LBG markets it should be conservatively assumed that no major premium biogas price would be obtainable – especially given the relatively small production levels likely for the foreseeable future.
CNG and LNG are expected to remain closely related to natural gas prices with a relatively limited potential for any price “premium” for biomethane.

**Electricity**

Similar to natural gas, electricity prices have a central influence in determining the economic performance of digester systems. The “retail” electricity price that farmers currently pay to meet their on-farm needs determines a maximum economic value for their potential electric cost savings earned by self-generation. The avoided cost for purchasing electricity at the utility’s retail price will offer direct economic benefit for dairies that can self-generate electricity on-site to meet their electricity needs. Electrical generation for on-farm use and/or net metering plays a vital role in the economic performance of current operating dairy manure systems (PERI, 2009).

**Net Metering**

Retail electric rates in California are comparatively higher than elsewhere in the United States and consequently will increase the potential economic attractiveness of alternative energy sources. Currently, the typical base “retail” electricity price facing farmers within the PG&E service area is $0.12 kWh to $0.14 kWh (including demand charges). However, during peak periods electricity prices can increase to more than $0.25 kWh (PG&E, 2010).

Past net metering regulations (called NEMBIO) did not encourage digesters operating as electricity “exporters” since the program only allowed them to “bank” their energy production in the utility grid. As a result, biogas producers often chose to flare excess biogas rather than generate electricity for which they would receive no compensation from their local utility. In addition, dairy farmers did not receive the full retail price for their self-generated electricity but still incurred tariff charges for transmission and distribution, demand charges, public purpose funds. These additional costs can be considerable – averaging $0.055 / kW-h (in 2005 dollars) for a typical dairy (Krich, 2005).

For unknown reasons, the NEMBIO program was closed to new entrants as of 12-31-09, and only a few dairies had joined the program while it was available. NEMBIO supported meter aggregation at a dairy but did not allow the sale of excess electricity back to the grid. It would be very helpful to dairy biogas electricity projects if NEMBIO could be re-instated and incorporated into the recently passed AB 920 legislation allowing for the sale of excess electricity back to the utility.

**Feed-In Tariffs**

Following the passage in 2006 of Assembly Bill (AB) 1969 (and subsequent CPUC rulings), PG&E and other California utilities are now required to buy excess energy generated with renewable sources from qualified customers. Daiaries that generate electricity can currently choose to sell their surplus electricity to their local utility under a Small Renewable Generator Power Purchase Agreement (PPA) provided they sell less than 1.5 MW of power (which at average of 0.107 kW/
cow would be equivalent to surplus power production by 14,000 cows). This “feed-in tariff” (FIT) program is in some ways a more sophisticated net metering program as the dairy’s usage and exports to the grid are both measured for quantity and by time of delivery. Under the feed-in tariff program, small renewable energy producers are able to obtain long-term contract for their energy production at a very low transaction cost which should assist in raising capital investment. This is a primary benefit offered by the feed-in tariff program to potential dairy digester developers.

Under the feed-in tariff program the purchase price for excess power is set by the CPUC according to the market price referent (MPR) determined as part of the State’s renewable portfolio standard proceedings. The MPR values offered under the feed-in tariff program are based on the comparable costs for electrical production at large scale utility power plants fueled by natural gas. As such, the MPR is unrelated to the actual cost of renewable energy production and therefore does not provide an appropriate subsidy to encourage specific renewable resources. Following the passage of Senate Bill (SB) 32 in October of 2009, industry participants are expecting improvements to the feed-in-tariff, in terms of both pricing (potentially placing a renewable adder on the MPR, or replacing MPR with a renewable-energy-based price) and structure (raising the size limit from 1.5 MW to 3 MW, enabling third-party developer participation, etc). However, the CPUC is currently focusing its efforts on the development of a “reverse auction mechanism” (RAM) for larger renewable energy projects (1-20 MW) and has not begun the process of implementing SB 32, which would benefit smaller renewable energy projects like dairy digesters. The prices paid for the surplus power is also adjusted for its “time of delivery” which recognizes the higher value of power supplied during on-peak periods and its lower value during off-peak hours. Current MPR values are approximately $0.09/kWh and producers can enter into 10, 15 or 20 year contracts with the utility (PG&E, 2010).

The feed-in tariff programs provide an improved mechanism for dairy digester to sell surplus electricity. However, the set price for the MPR and low off-peak rates can nonetheless result in average electricity prices that may be insufficient to fully compensate for the electrical generation system costs. Furthermore, the long term contracting terms lack escalation provisions and this can be a disincentive for electrical producers deciding between participating in the feed-in tariff or net-metering programs (if they were to become available again). However, it may also be possible with suitable gas storage and design that a digester system could be operated beneficially as a peak power operation under the feed-in tariff program so that the dairy sells mostly during peak or partial peak periods (PERI, 2008).

While the feed-in tariff program improves the revenue potential for on-site electrical production, it does not necessarily maximize the economic benefits to the dairy. Under the current feed-in tariff programs, the generator (dairy or developer) is prohibited by regulation from “wheeling” electricity from the dairy – even amongst the dairy’s own electrical accounts. For example, a dairy farm with several electrical accounts (e.g., for refrigeration, irrigation systems, lighting and home use) will have to sell the power in excess of that it consumes on its producing electrical line...
Key Factors Determining Economic Feasibility

(i.e., that connected to the generator system). Under the PPA agreement terms with the utility, the dairy would earn revenues (which may be near to a wholesale price) while at the same time being charged at a higher retail price for the electricity it is consuming on its other electrical accounts, assuming based on current pricing that the PPA price for renewable energy is lower than the retail rates for agricultural customers. Under this arrangement, the dairy could lose some of its potential avoided cost savings that it could earn if it was able to fully serve its own electrical needs from its own electrical production.

The feed-in tariff program is available on a first-come, first served basis and PG&E’s obligation for the program serving manure digesters and other non-water/wastewater customers will end when 104.6 MW of installed renewable generation will operate under the program. As of February 2010, only the Castelanelli Bros Dairy has enrolled in the program (PG&E, 2010), providing further evidence that the price of the feed-in tariff has been insufficient to stimulate widespread development of economically viable dairy digesters. The implementation of SB 32 will increase the overall statewide program cap by 750 MW (over the previous cap of 250 MW).

The most recent analysis predicts that California’s system-wide average retail electricity price will increase modestly in real terms between 2010 and 2016 (CEC, 2007). If electricity prices remain relatively stable, then there will not be increasing economic incentives for on-site electric generation use of dairy digester biogas, as conventional wisdom a few years ago would have suggested.

In summary, electricity prices are a direct and fundamental driver of dairy digester feasibility. The revenue boundaries for digesters systems are determined by both the retail prices paid by electrical consumers and the wholesale prices and contract terms by which utilities will purchase any on-site surplus electrical production using biogas / biomethane. The terms of any feed-in tariffs, PPA and other price factors (e.g., time of delivery pricing) will determine and incentivize the dairies’ production levels and use/sale of their biogas. Currently, much of these terms are set by the CPUC regulations and policy which determine not only the price of the feed-in-tariff but also authorize the utilities’ prices to its consumers and their ability to “pass on” any electrical purchase costs. Similar to other distributed generation and renewable resources, these financial factors may be expected to have a critical, albeit complicated role, influencing the economic feasibility for manure digesters in the Central Valley.

Byproduct Values

Digestate Use Values

Most feasibility studies of dairy digester systems estimate an economic value for use of the digestate by-products. Depending on its water content, the digestate can be spray applied to crops as a fertilizer supplement / replacement, used as compost material or livestock bedding material.

The quantity and form of the digestate will be related to the anaerobic process used. Lagoon digesters will result in predominately liquid digestate while the complete mix digesters typically produces a
denser slurry digestate. The plug-flow process results in a wet solid digestate material. The digestate can be heated or otherwise dewatered to separate the solid fraction for use as a compost material or bedding. If a dairy farmer has insufficient land to accept all its digestate, the material can generally be transported short distances to other nearby farm operations. In many cases, the digester owner will earn a small payment for the effluent (Martin, P., 2010).

The extent that the digestate by-product can be used as a soil supplement or fertilizer replacement will depend on the farmland soil conditions and crop types as concerns about salt and nitrate loading limit its land application rates within the Central Valley. Currently, single crop farming in the region can typically accept approximately 2,000 lbs of manure or digestate per acre annually while double cropped fields can receive 3,000 lbs per year. Given that a cow will produce approximately one ton (2,000 lbs) of manure solid a year, the quantity of digestate that will remain after anaerobic digestion will be approximately 60% or 1,200 lbs per cow per year (Clear Horizons, 2006).16

Some analysts argue that most digestate uses should not be recognized as an additional revenue source for the digester since the dairy’s manure would otherwise be similarly reused on-site. In which case it may be argued that no new net revenue has been generated unless manure or other feedstocks (if co-digestion is occurring) has been imported (Hall, 2010).

In any case, the potential value of avoided bedding costs will be very minor. Although bedding sales of digestate are commonly estimated to be approximately $20 - 25 per ton (Clear Horizons, 2006), according to USDA statistics, less than 0.28 percent of the total dairy budget was spent on bedding and litter materials for the average California dairy operation (USDA, 2005). Consequently the avoided cost of digestate use for bedding or revenues from their sales can be expected to have a minimal if not negligible effect on the economic feasibility of any manure digester systems.

The compost value of digestate is considered to be potentially significantly higher if it can be sold commercially.17 Green waste recyclers report sales of up to $18 per cubic yard ($90 per ton) (SAIC, 2002). However, wholesale values of the digestate may be far lower. In an analysis of a large centralized digester system Hurley estimates that the net value of the digestate would be $5 / ton which was consist with several other studies (Hurley, 2007).

Again, given the relatively minor net value of the bulky digestate and recognition that it is arguable that any net material gain has occurred (and in actuality likely to have been a 40% loss in biomaterial material weight in the manure to digestate conversion), the value of the solid digestate as a compost revenue may be expected to have a minimal contributory effect to the digester feasibility.

**Effluent Use**

Digester effluent is typically applied to dairy farmers’ fields for feed crop production. As discussed above for the solid digestate, it is arguable whether any revenues or avoided costs associated with

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16 Assuming substrate volatile solid content of approximately 65% (i.e., manure with bedding) of which 60% would be converted to methane.

17 Technically, the digestate is not actually compost material since it has not been aerobically decomposed, however it has very similar uses and nutrient value for soil application as compost.
the use of the effluent by-product will represent a net revenue contribution. Unless organic feedstock material has been imported (which would increase the effluent quantity and/or fertilizer value), then the farmer’s fertilizer expenditure would be expected to relatively unchanged. Consequently, only co-digesters or centralized manure digester systems would be expected to generate net revenues from digester effluent use that would represent additional revenues potentially improving the project’s feasibility. Furthermore, if the location of the digester has insufficient onsite capacity to accept on-field applications of all the generated effluent (or solid digestate), then disposal of the effluent could add costs that would further decrease the project’s economic feasibility.

The potential applied fertilizer cost savings with effluent use will have greater potential economic than solid digestate uses. Furthermore, unlike the quantity of manure solids which is substantially reduced by the anaerobic digestion process, most of the nitrate, phosphorus and, to a lesser extent, potassium content will remain in the effluent and digestate. As a result, any use of imported feedstock will likely add additional nutrients. While such nitrogen and other salt accumulation can present potential water quality concerns if improperly managed, or if the surrounding cropland is already at or near its maximum nutrient loading based on current operations, the high costs of fertilizer make it possible that effluent can have meaningful reuse value to the dairy and other nearby farms. Farm studies indicate that the fertilizer value of untreated manure can be significant – conservative estimates from a 1997 study estimate the annual value of untreated manure to be over $100 / cow (in 1997 dollars) (Hart, 1997). However, these fertilizer cost savings are also more applicable to higher value commercial crops rather than feed crops. Nonetheless, it can be reasonably expected that on a per cow basis, new net effluent gains would have some positive revenue value for the dairy.

It has been suggested by some industry analysts that large scale effluent treatment to separate out the nitrogen, phosphorous and other salts could generate highly valuable organic fertilizer byproducts that would be suitable for use by drip feed irrigation systems. Such an additional effluent processing component to the dairy digester facility would be costly with developer costs and economies of scale similar to those necessary for biogas upgrading systems. However, given the high costs for fertilizer purchases, the high concentrate organic byproduct would have significant value which according to some experts could be a major economic driver for the digester system (Best, 2010). Furthermore, such a digester effluent treatment system would sequester nitrogen and salt thereby improving the dairy’s water quality management practices. Outside of California, effluent treatment can sometimes be a key driver of the economic viability of digesters, as there can be a significant avoided cost associated with phosphorus and nitrogen removed from the waste stream in certain locations.

In general, net effluent gains for co-digesters or community digester systems may represent a positive albeit relatively minor supplemental economic factor for system feasibility (subject to local farmland soil conditions).19

19 Not including the development of major effluent processing component.
Tipping Fees (Co-digesters only)

Most co-digester studies argue that that tipping fees for the feedstocks processed by co-digesters are important revenue sources. Several studies have concluded that tipping fees can be crucial factors is determining the viability of the digester project (Moffatt, 2007).

However, it is essential that the net revenues for sourcing co-digester feedstocks are understood so that the net revenues to the digester project can be correctly determined. “Tipping fees” generally refer to the price paid for disposal of the organic wastes. In some cases, the waste producer may also incur additional transportation costs for removal of the waste. Co-digester operators sourcing feedstocks for their facilities will similarly need to recognize the costs for transportation (and possibility storage) of the feedstock to determine the cost-effectiveness of feedstock additions for their biogas production.

In most cases, waste-to-energy facilities are able to obtain a disposal or tipping fee for feedstocks that increase biogas production and add revenues that assist in offsetting facility construction and operating cost expenses. Such disposal fees currently range from about $50 to $60 / ton in California. However, most of the feedstocks are potential commodities for which supply, demand and prices are susceptible to change. Relatedly, most commercial feedstocks (e.g., agricultural or food processor wastes) are expected to be available only seasonally and on a short-term contract basis. Digester operators will likely have to obtain a variety of different feedstock materials from numerous sources. Municipal green waste is currently identified as one of the more reliable potential feedstocks. As competition increases for these resources this trend may reverse and tipping fees may decrease.

Costs for collection, transporting and storing agricultural residues uses are typically in the range of $25 to $50 per dry ton. Transportation costs of $0.20 to $0.60 per mile per ton are typical for feedstock delivery (Jenkins, 2006). Other analyses have identified loading and unloading costs of $0.40 / ton (2007 dollars) with a $0.18 / ton / mile transportation cost (Moffatt, 2007).

Tipping fees can offer additional revenues for co-digester systems but transportation and storage costs may reduce the net revenues for the digester operator. Given the uncertainties and geographic considerations associated with current and future feedstock commodity values, it is conservatively considered that tipping fees should be recognized as at most a minor secondary supplemental revenue source solely for co-digester systems.

Greenhouse Gas Emission Reduction Credits

There are two types of potential greenhouse gas (GHG) credits that many be derived from digester systems: (1) Credits for methane destruction (carbon offsets); and (2) Credits for Fossil Fuel Displacement (renewable energy credits).

Methane has 21 times the greenhouse gas impact of an equivalent weight of carbon dioxide (CO₂). Consequently, each ton of methane that is intentionally destroyed will have an equivalent GHG reduction value of approximately 21 tons of carbon dioxide. Use of renewable fuels for power generation also has a secondary benefit that carbon currently stored in fossil deposits is not added...
to the environment. Renewable Energy Credits (RECs) in effect account for the fossil fuel displacement effects and are discussed separately below.

A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” (i.e., the offset provider must prove that the project would not have happened without its financial investment and that the project goes beyond “business as usual” activity). If anaerobic digesters someday become the Best Available Control Technology (BACT) for dairies’ waste management, then digester collection of methane would no longer represent “additional” carbon reductions and so would no longer qualify as carbon credits. Under such circumstance, existing GHG credits would remain valid until the end of their ten year term but new credits would not be authorized (CCAR, 2007).

The methane collection and use associated with anaerobic digesters systems can result in considerable reductions in GHG releases. Flaring of collected biogas will result in a net GHG impact reduction as the more volatile methane is converted to carbon dioxide which has less than a twentieth of the climate change effect. Productive use of anaerobic digester biogas will result in additional GHG benefits as the biogas generated energy will reduce the corresponding utility generated GHG emissions that would otherwise be necessary.

Currently, there is an emerging international and domestic market for greenhouse gas emission offset credits (often referred to as carbon credits). Both the European Union (EU) and Chicago Climate Exchange (amongst others) operate “carbon markets” for the purchase and sale of certified carbon credits. In addition, potential GHG credits have to be certified to verify their effectiveness. Numerous organizations operate GHG verification programs both within the U.S. and internationally (e.g., the Voluntary Carbon Standard Association and Gold Standard Foundation). Within California, the Climate Action Registry (CAR) has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters.

Presently participation in GHG markets is voluntary within the United States. Nonetheless, many businesses are currently purchasing carbon offsets to support projects that reduce GHG levels. Consequently sales of carbon offsets may be an additional revenue source for future digester projects. However carbon offset prices are subject to market conditions and price volatility. Between 2005 and 2007, carbon reduction credit values were as high as $50 per ton of CO₂ equivalent (outside of the US). More recently, carbon values have been considerably lower - typically in the range of $10-$20 per ton, internationally, and between $1 and $10 per ton in the US. Since the market is based on both the supply and demand for carbon credits, it is difficult to project the future carbon credit values.

PG&E currently operates its Climate$mart program which allows participating customers to elect to pay an additional monthly premium to fund CPUC-approved projects that reduce GHG emissions. Climate$mart intends to acquire 1.5 million tons of carbon credits, making it an early leader in the California market. Residential, businesses and municipal customers participating in the...
ClimateSmart program are purchasing GHG offset credits which fund development of emissions reduction projects. PG&E estimates a current carbon reduction price of approximately $7 per metric ton of CO₂ for its ClimateSmart program. Given an annual GHG impact equivalent to 3.5 tons of carbon per year (CAR Protocol), the current potential carbon offset value for qualified dairy digesters would be approximately $24 per cow (Brennan, 2009).

Although there is currently uncertainty surrounding both the implementation of AB 32 and the prospects of a Federal cap-and-trade system, if either one or both systems were to move forward the resulting compliance market would likely create significantly higher prices for carbon offsets. CPUC estimates used in the MPR model, for example, include prices under AB 32 of $10-$40/ton (from 2012 to 2020), which could translate to more than $100 per cow.

**Renewable Energy Credits (RECs)**

Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as renewable energy, as discussed above. RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy. Recent regulatory developments, yet to be finalized, would enable RECs (referred to as tradable RECs or TREC) to count towards California’s Renewables Portfolio Standard (RPS).

Renewable Energy Credits (RECs), as statutorily defined, are not created until electricity is generated. Therefore biogas digesters, unlike wind turbines and geothermal facilities, in and of themselves have no RECs to convey. However, if the digester biogas end use will replace the use of fossil fuels for energy production then the digester can qualify for fossil fuel displacement credits. Consequently, biomethane production for use as transportation fuel will not qualify for RECs.

As a renewable resource that can directly substitute for natural gas use, biomethane or biogas used for electrical generation or injection into the utility grid will qualify for RECs.

A digester system developer retains the RECs for self-generated power used on site while the utility receives the remaining REC credits for any surplus electricity it has purchased. Utilities and other entities that need these “green tags” may be potential purchasers of digester RECs. In addition, other businesses wishing to support renewable energy might also be interested in purchasing digester power RECs. REC prices are subject to market conditions but could be expected to be $0.02 to $0.05/kWh.

**Key Factors Determining Economic Feasibility**

- **Costs:**
  - Capital costs: Initial investment for digester and associated infrastructure.
  - Operating costs: Fuel, maintenance, labor.
  - Revenue stream: Sales of electricity, biogas, or credits.

- **Carbon Credits:**
  - Local: California carbon offset credits (calCCAR).
  - National: Renewable energy credits (RECs).

- **Fiscal Incentives:**
  - State and federal tax credits or incentives.
  - Feed-in tariffs or other payment mechanisms for renewable energy.

- **Regulatory Framework:**
  - Renewable Portfolio Standards (RPS) and other regulations requiring renewable energy usage.
  - Carbon accounting and measurement standards.

- **Market Conditions:**
  - REC prices: Vary widely based on supply and demand.
  - Carbon credit markets: Fluctuations due to policy changes and international agreements.

- **Financial Analysis:**
  - Payback period: How long it takes to recoup the initial investment.
  - Net Present Value (NPV): A measure of the profitability of an investment.
  - Internal Rate of Return (IRR): The discount rate at which the NPV equals zero.

**Notes:**

20 Consequently, biomethane production for use as transportation fuel will not qualify for RECs.

21 The CPUC issued Decision 10-03-021 on March 16, 2010, in Docket No. 06-02-012 under its Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard (RPS). In the Decision (p. 59), the CPUC adopted a temporary price cap of $50/MWh for RECs, which is the penalty amount for noncompliance with the RPS. This $50/MWh temporary price cap for RECs is used as the upper end of the 15 year term but new credits would not be authorized (CCAR, 2007).
Currently, most RECs within California are sold bundled with the associated renewable energy. Consequently, utilities such as PG&E that are negotiating long term renewable energy purchases acquire the REC values with the resource’s material value as a fuel. Consequently, the sale price for the renewable resource has a price premium/component for the included REC. However, the price for feed-in-tariff for small renewable generation does not include the value of the REC, even though the REC is bundled with delivery of electricity under the tariff. The REC values for self-generated energy used by the dairy will be retained and would be potentially available for sale.\textsuperscript{22}

There are no established REC values for biomethane use as a transportation fuel. However, future implementation of the California Low Carbon Fuel Standard (LCFS) is expected by many industry experts to encourage the future of REC values applicable for future use of biomethane (either as CBM or LBM) as a replacement for diesel and gas fuel (Price, 2010). Although very difficult to value at this point in time, some industry experts maintain that the future REC values for biofuels could add additional revenues for digesters systems producing CBM or LMB.

**Other Economic Benefits of Sustainable Farm Production**

Currently, several of the farms with operating digester systems receive significant attention for their pioneering sustainability improvements and use of biogas as a renewable energy source. Hilarides Dairies use of cow power for its trucks and Fiscalini Farm’s use of its biogas for its cheese production are two notable examples. Similarly, the Straus Family and Gallo Farms also differentiate their dairy operations by their implementation of more sustainable farming practices.

Walmart has started to ask its milk suppliers to bring lower carbon content milk to them but as yet they are not offering any price premium for this product so little action has taken place.

However, as yet there is no appreciable market or economic value to these and other California dairies rewarding them for adopting more sustainable business practices. While “greener” businesses in other sectors may be able to leverage their sustainability commitments for an improved market position or marketing benefit, there is currently little potential for dairy farms to capture any such similar benefits. Due to California’s regulated milk sales market and relatively few dairy producers that sell directly to retailers, most dairy farmers are “price-takers” (LaMendola, 2010). Dairies such as Straus Family Farms that have a brand identity and sell their dairy goods to consumers are very few in number and represent a very small portion and niche of the dairy market. Premium prices for “greener” dairy producers are unlikely to be achievable in the foreseeable future particularly during a depressed economy and relatively low public awareness of the potential for more sustainable production practices such as dairy digesters.

Furthermore, due to the largely consolidated market for most dairy goods and the perishable nature of milk itself, emergence of any sales premium or selection preference for dairy products from “sustainable” dairy farmers will likely require a considerable increase in prevalence and/or accreditation labeling (i.e., a “green” stamp of approval) before wholesalers and/or other large range. The lower end of the range of value for RECs is based on the $20/MWh market price index for RECs for the Western Electricity Coordinating Council, as quoted by the CantorCO2 Environmental Brokerage.

\textsuperscript{22} The sale and purchase of tradeable REC’s for utility compliance with RPS is currently under agency review and consideration by the CPUC.
customers can and will begin to select amongst dairy producers for those more sustainable producers.

As a result, it is considered unlikely that dairy farmers will be able to gain any significant economic premium for their dairy products from their digester operations.

Government Grants and Assistance

Currently most operating digester systems receive considerable government funding assistance. Anaerobic digester projects qualify for many of the federal and state programs promoting renewable resource development. Governmental assistance and support can be provided in the form of form grant funding, low-interest loans, tax incentives and/or technical support. The main forms of government support currently available for biomethane production by dairy manure digesters are identified below. Individual digester projects will have to qualify for assistance on a case by case basis and projects will typically receive assistance from only a few programs.

*Renewable Energy Production Tax Credit.* Under this federal program authorized by the 2005 Energy Policy Act, qualifying renewable energy producers can obtain $0.015/kWh in production incentives. The program is currently authorized to continue until 2026.

*USDA – Renewal Energy Program.* The program provides grants and loan guarantees to rural small businesses and agricultural producers for up to 25% of the cost to purchase and install renewable energy generation systems up to $500,000.

*Self-Generation Incentive Program for Renewable Fuel Cells.* Authorized by the CPUC, this utility administered program provides financial incentives for installation of new, self-generation equipment installed to meet all or a portion of the user’s electric energy needs. The program was originally designed to complement the CEC’s Emerging Renewables Program (ERP) by providing incentive funding to larger renewable and non-renewable self-generation units up to the first 1 MW in capacity and subsequently increased for units up to 3 MW in capacity. Renewable fuel cell systems can receive a $4.50/watt as a one time capital payment (but not to exceed 50% of the total cost). Non-renewable fuel cell systems can similarly receive a $2.50/watt capital payment.

*California Energy Commission - Renewable Energy Program.* The Existing Renewable Facilities Program provides production incentives, based on kilowatt-hours generated, to support existing renewable energy facilities. In addition, the Emerging Renewables Program provides rebate funding for solar and fuel cells that use renewable fuels (such as biogas). The program has $65.5 million in funding until 2011.

*State Assistance Fund for Enterprise, Business and Industrial Development Corporation: Energy Efficiency Improvements Loan Fund.* This long standing state program offers low interest loans to small businesses in California for renewable energy systems. The maximum loan amount is $350,000 at 4% interest with a five year repayment period.

23 The Feed-in Tariff program authorized by the CPUC is discussed previously under the electricity price section.
In addition to these current programs, the State of California (administered by the CEC) provided significant funding assistance to manure digester and other similar renewable resource projects through both its former Dairy Power Production Program and research conducted under its Public Interest Energy Research Program (PIER). As discussed previously in the Renewable Energy Credits discussion, the State of California Renewable Portfolio Standard (RPS) requirements also provides indirect support for manure digesters by fostering an emerging market within California for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters.

Recent economic analysis of dairy digester systems installed under the California Dairy Power Production Program determined that without government subsidies, even the best constructed / operated digesters would have electrical production costs that are “high tending to be above market rates” (PERI, 2008). Even factoring in government subsidies, the cost of energy for other digester systems were such that while several digesters were marginally profitable, several others operated at a negative rate of return.

Together these past and current programs illustrate the important role that state and federal programs contribute to fostering the development of manure digester systems. The financial and technical support is widely agreed to be an important and positive influence improving the feasibility of manure digester development. Furthermore, given the increasingly complex regulatory conditions facing dairy farms and renewable energy projects, as well as the financial challenges remaining before full commercialization of the manure biogas/biomethane production is expected to occur, continued governmental support is expected to remain an important and essential economic driver for future manure digester development for the feasible future.

**Cost Factors**

These costs typically will consist of both:

- Initial construction and equipment costs for development of the digester project. In many cases there may be significant economies of scale as the system capacity increases. The construction and/or equipment cost will also likely vary depending on the technology adopted.

- Operating and maintenance cost for the project. This will include the labor and input costs including required energy. Typically, these are variable costs and will vary with the level of production. The operating and maintenance cost may also vary depending on the technology adopted.

The following section identifies the major cost factors that influence the economic feasibility of biogas production by dairy manure digester systems. These factors are naturally inter-related with the revenue factors discussed above. Just as market conditions will determine the revenue potential for digester biogas and its other byproducts, technological and equipment supplier conditions will be key cost determinants on economic viability. Consequently, major technological improvements that greatly decrease unit production costs will enhance the economic feasibility of dairy digester development. Conversely, additional equipment / processing requirements (i.e., as result of new
regulatory compliance requirements) that increase unit production costs will reduce the dairy digester system’s economic viability.

As will be discussed below, economies of scale can have an important role determining unit production costs and consequently the economic feasibility of the system. In some cases, scale issues will be limiting factors. Major equipment components may require minimum quantities of process throughput to operate adequately and in such cases these technological/operational constraints may dictate system design parameters.

Finally, it is worth noting that costs are generally easier to estimate than revenues which typically face more future variables. This is particularly apparent when the digester system’s operating assumptions and conditions are defined. Review of past digester studies offer far greater cost information than is provided for their revenue projections. In any case, care should be taken to ensure that estimated costs are properly matched with operational / output assumptions. It should also be recognized that site specific conditions can both positively or negatively affect the actual system development costs considerably.

**Manure Collection / Preparation as Feedstock**

The dairy manure collection costs for on-farm digesters are considered to be negligible since similar manure management practices are already a necessary component of existing dairy operations. Furthermore, the transportation distance within the farm will be very limited. In addition, relatively little pre-digester preparation is expected to be necessary for the manure. Any grinding or filtration necessary will be very minor in cost compared to the digester itself.

For a centralized or community digester system, manure transportation costs may be a limiting factor that could offset economies of scale that might be gained from larger anaerobic digester facilities. Manure from the individual farms could either be piped to the centralized digester through a sewer system or possibly be transported by trucks. Analysis by Ghafoori and Krich suggest that development of a piping system for dairy manure is prohibitively high from a construction cost basis (Ghafoori, 2005; Krich, 2005). Furthermore, such systems would incur major additional investment cost and could face significant additional difficulties with site and easement requirements.

**Anaerobic Digester Systems**

As discussed previously, anaerobic digester systems are relatively simple and well established technologies. Although there is potential for future productivity improvements, construction specifications and costs are relatively well defined. Most of the system components are relatively standard and readily available. Other construction costs (e.g., such as siting and land preparation) will be relatively straightforward.

The selection of specific anaerobic digester technologies will be primarily determined by the dairy’s manure management systems. While site specific requirements may necessitate some tailoring of digester configurations, construction costs should be relatively comparable between dairies located within the region. As a relatively simple and mature technology, future equipment
and development costs for anaerobic digester systems are not expected to change substantially. Future technological improvements are expected to be predominantly incremental. Therefore, while digester system construction costs will represent a secondary factor in determining the economic feasibility of manure digester systems, this cost factor is expected to remain relatively constant and therefore represents a minor economic driver.

Operating and maintenance costs for digester systems remain largely under-analyzed. If feasibility studies consider the system operating and maintenance costs at all, most typically attributed a percentage cost of the project’s construction cost. While improved remote sensing and automated control systems can assist digester management tasks, many industry analysts agree that most studies do not fully recognize the labor likely involved to operate digester systems (Summers, 2010).

In any case, given the comparative simplicity and mature technology used for manure digester systems, operating and maintenance costs may be expected to make a very minor contribution to the digester overall economic feasibility. Furthermore, no significant cost improvements can be expected to the anaerobic digester process that would substantially improve overall system feasibility.

**On-site Heat/Boiler System**

On-site heat generation from biogas is predominantly used for heated complete mix or plug flow anaerobic digester systems. Otherwise, unless major milk processing is occurring on-site, most dairy’s heating demand will be relatively limited and can be met with standard boiler systems that can be fairly easily modified for use with biogas (although air quality compliance may be problematic). The capital cost for conversion or purchase of suitable heating systems will be relative minor. In most cases, heat generation will be limited and only a secondary use for dairies of any produced biogas. Therefore, heating use of biogas will have a very minor influence on the digester’s economic feasibility. Furthermore, no major technological improvement or future significant cost savings can be expected related to biogas heating systems that would improve overall system feasibility.

If on-site electrical generation with biogas is planned, combined heat and power (CHP) designs typically can offer cost effective opportunities to use thermal energy that would otherwise be lost. However, given most farm’s limited heating needs it likely that surplus heat would still be generated. Consequently, while their may be opportunities for cost effective efficiency gains, the magnitude of the economic benefits will remain minor and will not be expected to be a significant economic driver of system feasibility.

**On-site Electrical Generation**

As discussed above, on-site electrical generation has generally been the primary use of biogas produced by on farm digester systems. Except for the Vintage Dairies facility which is producing biomethane for pipeline injection, all the other manure digester systems operating in California are using their biogas production to produce electricity on site. If on-site electrical generation with biogas is planned, combined heat and power (CHP) designs typically can offer cost effective opportunities to use thermal energy that would otherwise be lost. However, given most farm’s limited heating needs it likely that surplus heat would still be generated. Consequently, while their may be opportunities for cost effective efficiency gains, the magnitude of the economic benefits will remain minor and will not be expected to be a significant economic driver of system feasibility.

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24 Hilarides Dairy also produces compressed biomethane with some of its digester biogas for use as a biofuel by its specially converted trucks.
range of production scales and under a wide variety of operating conditions. Generally speaking, outside California, electrical production with internal combustion engines can be cost effectively performed to meet not only all on-farm needs but also to generate surplus electrical energy which can be exported to other users or to the grid under net-metering or distributed power arrangements with local electrical utilities.

The national average on-site electrical usage for dairies is 550 kW / cow / year (Barker, 2001). At a typical retail energy cost of $0.12 kWh, the annual electrical cost for each dairy cow would be $66. If it is conservatively projected that each dairy cow can generate 0.1 kW, then an annual basis total value of the potential electrical production would be 876 kWhr / cow / year which would be worth approximately $105 per year per cow of which approximately $39 per year would be the potential value of the surplus electricity at average retail electricity prices.

Yearly operation and maintenance costs for electrical generation systems are typically estimated to be in the range of $0.015/kWh (Jewell et al., 1997; Hurley, 2007) which reduces the system operator net revenues/saving.\(^{25}\)

However, as discussed in more detail below, future electrical generation with biogas at dairies within the Central Valley is highly problematic due to recent air quality regulations that prohibit IC engine use unless NOx emissions can be reduced to 9 – 11 ppm or less. It is currently unclear whether the use of on-site electrical generation equipment can be cost-effectively applied in the near term for dairy digester systems in the Central Valley.

On-site generation of electrical power is an important potential use option for dairy digester biogas/biomethane. As a form of distributed power, such on-site systems offer possible direct economic benefits and reduced overall environment impacts. However, given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically infeasible in the Central Valley based on currently available electricity prices.

**Biogas Upgrading**

The fundamental purpose of biogas upgrading is to increase the proportion of methane from its 50 to 65% concentration to near pure methane (95-99%) while removing the corrosive H$_2$S and CO$_2$ impurities.

The specific gas quality standards for biomethane to be accepted into the PG&E natural gas system are set in PG&E Gas Rule 21.C and by Rule 30 requirements for SoCalGas. Key utility specifications include less than 1% CO$_2$ and 4 ppm of H$_2$S content.

The upgrading requirements for biomethane production to pipeline injection standards are comparable (and typically higher) than those required for CBM or LBM production. Therefore the primary economic differentiators between biomethane uses (e.g., pipeline injection, compressed biomethane

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\(^{25}\) Although as discussed under the Electricity price section, under the net metering program additional tariff costs for transmission and distribution, as well as demand charges may also be incurred. In addition, the interconnection process prescribed by CPUC Rule 21 can also require additional costs to the dairy.
or liquefied biomethane) will be associated with subsequent delivery and market requirements for the different uses.

There are three main processes necessary for refining biogas into biomethane. The technologies for each of the procedures are well established and widely used but generally are implemented at a scale far larger than the production levels that even large dairy digesters would be able to attain based on their own herd size.

**Scrubbing (H₂S removal)**

Hydrogen sulfide (H₂S) is a highly corrosive impurity within biogas as it readily combines with water to form sulfuric acid. Generally, H₂S concentrations in raw biogas are typically 0.5% or less and can be problematic for many gas uses. However, for “lower tech” applications (such as boiler systems or internal combustion engines) regular and increased maintenance can be used to cost effectively manage most of the potential corrosion effects. Of the numerous potential scrubbing processes, iron sponge scrubbing is generally considered the most suitable for on-farm H₂S removal (Krich, 2005).

**Conditioning**

Water removal from biogas is a relatively straight forward and can be achieved through refrigeration of the biogas to condense out the water content. Using a relatively inexpensive commercial refrigeration unit and minor parasitic energy loss (2%) the water content in the biogas can be adequately reduced to acceptable levels.

Carbon dioxide is the most critical and expensive impurity to remove from biogas. Due to its relatively inert chemical composition and high concentration levels within the digester biogas, more extensive gas treatment is necessary for carbon dioxide removal. Water scrubbing is a relatively simple and low cost conditioning that is considered suitable for on-site dairy use. Although less efficient than other “higher tech” approaches, water scrubbing is most environmentally benign. Alternatively pressure swing adsorption (PSA), amine scrubbing and other technologies are available which offer some advantages for some applications (e.g., compatibility with LBM) but also present cost or environmental byproduct disadvantages.

Biogas upgrading is likely necessary for any off-site use of digester biogas. The processing equipment, and to a lesser extent, the operating and maintenance costs, required for biomethane production will add considerable cost to the digester system. In addition, approximately 15% of the methane content is lost during the upgrading process. As a result, the unit cost for the biomethane will be increased substantially. While increasing the size of production levels can help to lower the unit cost of production, the volume of production necessary for most applications of the scrubbing and conditioning equipment remain relatively high due to the fixed cost of the technology. Furthermore, diseconomies of scale may begin to be incurred if the digesters can not be favorably located and clustered. Several previous feasibility studies have suggested that biogas upgrading systems would need to process the biogas of 10,000 cows although other suggest that full production cost efficiencies for pipeline injection would require 30,000 cows (Goodman, 2010).
As a result, unless future technology improvements can cost-effectively scale down biogas upgrading systems, it is likely that current biogas upgrading technology requirements will remain a major factor restricting economic feasibility.

**Distribution / Transmission System**

The construction costs for biomethane pipelines can vary considerably. Typically pipeline costs are estimated to range from $100,000 to $250,000 per mile. While the operating cost for pipeline delivery will generally be very low, the initial construction will represent a significant additional investment cost – especially compared to tanker truck delivery. Given the comparatively high cost for pipeline delivery, it has generally been judged that pipeline delivery of biomethane for any significant distance will not be economically feasible. Some analysts suggest that at most one or two miles in most cases would be a limiting distance for pipeline use (Krich, 2005). Others maintain that up to five miles may be viable under certain conditions (Brennan, 2010).26

Pipeline distribution costs also will play a fundamental role determining the feasibility of a centralized biogas treatment facility serving several dairy digester systems. Cost effective development of a centralized biogas treatment facility will require the farms’ digester systems to be clustered close together. Furthermore, the combined biogas production must be sufficient to ensure an adequate supply to attain the necessary economies of scale for cost-effective biogas upgrading. Otherwise, the pipeline transmission costs to import the additional biogas from more distant producers may place additional cost burdens that undermine the collective enterprise’s overall feasibility.

CBM and LBM production will require both storage and truck transfer facilities. Standard and relatively inexpensive propane tanks can be used for low pressure biomethane storage (i.e., up to 300 p.s.i.). This is most suitable as intermediate storage of the biomethane output from the upgrading facility. Biomethane must be further compressed to 3,000 to 3,600 p.s.i. (i.e., equivalent to CNG pressure) for delivery and use as a transportation fuel. LBM has to be liquefied at pressures of over 5,000 p.s.i and maintained at low temperatures. Such high pressure storage is expensive and relatively complex to maintain. For pipeline injection of biomethane, only limited on-site gas storage facilities will be necessary.

**Pipeline Injection**

Currently, although California utilities are willing and able to purchase biomethane produced by manure digesters, the supplying dairy must provide all the facilities necessary to deliver pipeline quality biomethane to the utility’s natural gas transmission system. Furthermore, the dairy (or third-party developer) must also perform the scrubbing and compression of the biomethane as well as install and operate the metering equipment and pipeline tap (Brennan, 2010).27 In addition, proximity to the natural gas transmission line will also be a major limiting factor. As discussed earlier, pipeline delivery costs will likely ensure that any biogas/biomethane production facilities

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26 PVC like pipe materials are also available for raw biogas transmission. However, as an even lower-grade and less valuable fuel it is will be less economically feasible to transport than the refined biomethane.

27 PG&E will provide the pipeline tap and metering equipment for large suppliers (i.e. those delivering 500 M cu.ft. or more per day).
for pipeline injection will have to be located at most a few miles from suitable connection locations to the transmission line.

Biomethane producers injecting biomethane into the existing natural gas transmission pipeline will incur an interconnection cost. Interconnection costs to the biomethane producer will vary depending on the utilities being served. Recent estimates for the connection cost for biomethane injection into PG&E transmission system are $0.265 million for biomethane producers injecting less than 500,000 cu.ft. per day. SoCalGas will charge biomethane producers the same rates as those for a tradition natural gas interconnection. Projects injecting up to 1 MM cu.ft. / day will pay approximately $0.8 million to access the SoCalGas transmission system (Anders, 2007).

The connection costs for pipeline injection are considerable and will require a greater scale of production so that the added costs can be adequately distributed to result in a manageable unit cost basis. In any case, the utility connection costs will represent a significant factor reducing the potential economic feasibility of biomethane production from dairy digesters. Furthermore, pipeline injection use of digester biomethane will be geographically constrained due to the high cost for any pipeline or vehicle transport of the biomethane between the digester and suitable injection points which must be along the natural gas transmission system.

**Compression / Liquefaction**

Methane requires 5,000 psi for liquefaction, and approximately 600 psi for transmission pipeline injection, and it requires major applied energy to attain such pressures. Compression of biomethane only to 1,000 psi requires approximately 207 Btu of energy to compress each 1,000 Btu – a considerable parasitic energy “loss” or cost of 20.8 percent (Hansen, 1998), in addition to methane lost during earlier stages of the conditioning process. This does not include efficiency losses associated with the compression engines themselves.

There are major scale constraints for liquefaction and distribution of biomethane. Due to the cryogenic nature of liquid biomethane, significant energy must be used to maintain the produced LBM at very low temperatures to avoid the liquid “boiling off.” The potential energy losses for storage of LBM can be significant. Therefore, industry analysts suggest that liquefaction facilities should at a minimum be sized to produce adequate LBM to fill a standard tanker truck (approximately 10,000 gallons) every three or four days to reduce on-site storage losses.

**Biomethane for Fuel Use and Conversion Costs**

In recent years, the State of California has conducted extensive analyses and taken several actions intended to encourage the development of alternative vehicle fuels including Executive Order S-06-06 and most recently Executive Order S-01-07 (the Low Carbon Fuel Standard) requiring a 10 percent reduction in the carbon intensity of transportation fuels by 2020. Currently, compressed natural gas (CNG) is used as a petroleum alternative for cars and other light use vehicles. In addition, liquefied natural gas (LNG) is also being developed as a fuel source suitable for heavier industrial vehicles. While new CNG and LNG vehicles are available for commercial purchase, the existing market is relatively small and these alternative fuel vehicles are more costly. In addition, some
diesel and other vehicles can be retrofitted to use a natural gas fuel. However, the costs are considerable and even high-use vehicles will have a long payback period from an economic feasibility perspective.

Compressed biomethane (CBM) and liquefied biomethane (LBM) are both potential substitute fuels for CNG and LNG vehicles. However, as with the CNG and LNG markets, although demand has been growing, this alternative fuels market is still at an early stage of development. Currently the majority of CNG and LNG vehicle fleets belong to municipalities. While this may offer some opportunities for partnerships, these will be geographically limited and will have a very finite demand until wider public adoption of CNG or LNG occurs. In addition, greater adoption of CNG and LNG as alternative fuels also faces strong competition from ethanol and biodiesel, which to date have received considerable and greater federal and state support.

Currently, nearly all of the LNG within California is imported over land in its liquid form by truck. Therefore, until planned LNG terminals in Southern California are completed, LBM produced in the Central Valley could have a transportation advantage over LNG. However, it is unclear whether the magnitude of this transportation cost savings will outweigh the higher production costs currently projected for LBM.

Consequently, the market potential for CBM and LBM is far from assured and participation as a fuel provider will face additional production costs (vehicle conversion, possible development of on-site fueling infrastructure). Therefore, given the absence of clear market demand and purchasers, the feasibility of production of CBM or LBM for bio-fuel sale is uncertain since it is difficult to determine the likely market price that producers would actually be able to obtain.

### Overall Digester System Construction Cost Estimates

As discussed above, the capital costs for manure digester systems’ construction and equipment costs will vary depending on both the size and configuration of the planned system. Irrespective, even the simplest of manure digester systems are relatively costly. Table 2 shows the costs and grant funding obtained for nine dairy digester systems in California. The cost estimates include the electrical generation facilities.28

<table>
<thead>
<tr>
<th>Dairy</th>
<th>Digester Type</th>
<th>Size (kW)</th>
<th>Annual Energy Production (KWh)</th>
<th>Debt Capitalization</th>
<th>Grant</th>
<th>Equity Capital Cost (a)</th>
<th>Capital Cost (a) ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hilarides</td>
<td>Covered Lagoon</td>
<td>500</td>
<td>3,383</td>
<td>0%</td>
<td>40%</td>
<td>60%</td>
<td>$1,392,000</td>
</tr>
<tr>
<td>Cottonwood</td>
<td>Covered Lagoon</td>
<td>300</td>
<td>2,133</td>
<td>0%</td>
<td>31%</td>
<td>69%</td>
<td>$3,132,000</td>
</tr>
<tr>
<td>Blakes Landing</td>
<td>Covered Lagoon</td>
<td>75</td>
<td>253</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
<td>$392,000</td>
</tr>
<tr>
<td>Castelanelli</td>
<td>Covered Lagoon</td>
<td>160</td>
<td>1,135</td>
<td>0%</td>
<td>57%</td>
<td>43%</td>
<td>$1,123,000</td>
</tr>
<tr>
<td>Koetsier</td>
<td>Plug Flow</td>
<td>260</td>
<td>540</td>
<td>0%</td>
<td>0%</td>
<td>100% (a)</td>
<td>$1,537,000</td>
</tr>
</tbody>
</table>

28 As discussed earlier, new digester development for electrical production will incur substantially higher equipment costs as more expensive generation system are now required to meet subsequent and more stringent air quality standards limiting NOx emission to 9ppm.

## Table 2

### Table No./Title

Appendix A
### Key Factors Determining Economic Feasibility

<table>
<thead>
<tr>
<th>Facility</th>
<th>Flow Type</th>
<th>Capacity</th>
<th>Biogas Production</th>
<th>Biogas Quality</th>
<th>Capital Cost</th>
<th>Operating Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Van Ommering</td>
<td>Plug Flow</td>
<td>130</td>
<td>489</td>
<td>0%</td>
<td>$973,000</td>
<td>$488</td>
</tr>
<tr>
<td>Meadowbrook</td>
<td>Plug Flow</td>
<td>160</td>
<td>1,100</td>
<td>0%</td>
<td>$1,185,000</td>
<td>$406</td>
</tr>
<tr>
<td>IEUA</td>
<td>Modified Mix Plug Flow</td>
<td>943</td>
<td>7,672</td>
<td>0%</td>
<td>$14,543,000</td>
<td>$14,422</td>
</tr>
<tr>
<td>Eden-Vale</td>
<td>Plug Flow</td>
<td>180</td>
<td>457</td>
<td>0%</td>
<td>$904,000</td>
<td>$5,021</td>
</tr>
</tbody>
</table>

a Capital Costs have been adjusted for inflation into 2010 dollar terms.
b Koetsier and IEUA received their subsidies as 5 year production payment instead of grant funding.


Other studies report similar cost estimates for developing dairy digester systems. Recent analysis for comparably sized dairy digester systems in Vermont reported capital costs between $4,000 to $7,800 per kW in 2010 dollar terms (Dowds, 2009). Similarly, the approximate initial total cost for developing a 400kW digester system at Fiscalini Farms in Modesto California was reported to be over $2 million, equivalent to more than $5,000 per kW in 2010 dollar terms (Gannon, 2008). However, subsequent additional design and development requirements resulted in a final system cost of approximately $4 million of which only $1.4 million was obtained from grant funding (Dairy Today, 2010). The Gallo Farms Dairy estimates that the cost of its 700 kW digester system was approximately $3.5 million in 2010 dollar terms which is equivalent to a $5,000 per kW capital cost (Pacific CHP Application Center, 2010).

As discussed above, digester systems developed for production of biomethane will require considerable additional upgrading equipment to remove the CO\(_2\) and other impurities. In addition, compressor and storage systems will be needed if liquefied or compressed biomethane is to be produced. If the upgraded and compressed biomethane is to be injected to the utility pipeline, then pipeline injection may require additional on farm (and possibly off-farm) pipeline to the utility’s natural gas transmission line as well as interconnection, controls and monitoring facilities to ensure the quality of gas supplied to the utility.

As discussed previously, most current biogas upgrading systems require relatively high gas throughput volumes for optimal performance. Consequently, biomethane production will incur additional costs from increased scale of production as well as the additional facility and equipment requirements. Industry experts currently maintain that at a minimum manure for 10,000 cows would likely be necessary (without co-digestion) to generate sufficient biogas to supply a biogas upgrade facility to operate efficiently. While dairy farms would not need to invest in electrical generation systems, there would nonetheless be major additional cost for farm-sized biomethane production. Preliminary cost estimates for the CEC project interconnection costs of $250,000 and pipeline costs of at least $50,000 for the existing California digesters (PERI, 2009). The cost for biogas upgrading facilities was estimated to vary from $400,000 to $750,000 (depending on the plant capacity). The savings from the reduced electrical generation capital cost also varied greatly from as high as $800,000 for Hilarides Dairy to just under a $100,000 for other dairies. Excluding the Blakes Landing and Castelanelli Dairies which were 5 miles or further from a suitable utility connection site, the total additional capital cost for pipeline injections was generally $500,000 to $700,000 higher than

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29 For farms located 5 miles from a suitable transmission utility connection site the pipeline cost was $1 million.
Key Factors Determining Economic Feasibility

for on-site electrical generation (PEIR, 2009). The study also projected that there would be a 15 percent loss of the original biogas quantity by the upgrading process, in addition to the substantial parasitic load associated with compression.

Although preliminary and specific to the existing digester systems, the PERI cost analysis demonstrates the considerable additional capital cost involved in dairy digester development for biomethane production.

Implementation Factors

Farmer Interest

Dairy production is the core business for dairy farm owners most of whom also must manage some feed-crop production on their farms. Modern dairy farm management is itself a complex business requiring considerable time and expertise to successfully manage milk production and maintain regulatory compliance. This is particularly true during recent years as a poor national economy has adversely affected the California Dairy industry. Although 2008 was a year of record production with high milk prices, in the first half of 2009 dairy producers faced increased production costs – partly from increased feed costs resulting from reduced production as many Midwestern crop farmers shifted their production to feedstock crops for bio-ethanol production. For the first quarter of 2009, the average cost of production for California dairy farmers was $18.51 / cwt. More importantly, as a result of overproduction and reduced foreign demand, milk prices fell by early 40 percent between 2008 and 2009 to $10.47 / cwt - their lowest level since June 2003.

Furthermore, feed expenses represent the majority of the dairy farmer’s cost. In 2005, nearly 58 percent of the average Californian dairy farmer’s total cost of production was spent on feed while less than 3 percent of the total dairy budget was spent on electricity, fuel and lubrications for the farm operations (USDA, 2005). Consequently, the potential direct energy and/or fuel cost savings from a digester will represent, at best, a very minor benefit to the farm’s budget and any such savings may be easily outweighed by any feed price changes.

Not only must dairy farmers be willing to accept the necessary investment and operating risk to develop digester systems, farmers must develop the technical capabilities and have sufficient professional interest in assuming the secondary occupation of biogas production (Sempra, 2009).

In the face of such volatility and adverse economic conditions, without clearly attainable net financial earnings, few dairy farmers may be expected to assume the additional costs, risks and responsibilities necessary to develop dairy digesters.

30 Except for Hilarides Dairy which had an unexplained but very major cost saving (approximately $788,000 in 2007 dollars terms) for replacement of its electricity generation equipment.
Capital Availability

The interest rate associated with the initial capital investment (and to a lesser extent managing the operations cash flow needs) will play an important role in determining digester feasibility. Low interest loans and favorable tax depreciation allowances can have an important contribution in reducing the loan repayment burden that a facility must support.

The useful project life for digester systems will have an important role in affecting the economic feasibility of proposed digester and related biogas treatment facilities. A longer useful life will increase the period over which the facility’s capital investment can be earned back. However, due to the interest and inflation effects to the capital investment, future earnings at later periods in a facility’s operations typically will have a lesser contribution to offsetting the initial capital investment.

There are two key factors determining the availability of capital for farm digester systems. First, the dairy farm’s financial situation will be a fundamental determinant of its ability to borrow capital. The amount of equity that a dairy has in its business, its cash flow and the amount of the loan required will determine the likelihood that the farmer can qualify for a loan. Given the recent financial challenges facing the Californian dairy industry, it is expected that few dairies will be able to qualify for the necessary loans from commercial banks to fund the development of major digester facilities, and those that would qualify may prefer to preserve their available borrowing capacity as opposed to pursuing digester facilities.

In addition to the dairy’s financial position, commercial banks must also be willing to provide the loans. Given the currently tight credit market facing the entire economy and the dairy industry’s current poor market conditions, it may be expected that many banks will be unwilling to provide lending for digesters – especially under relatively favorable terms.

Therefore, due to the challenges facing the dairy industry and the generally weak credit market, few dairies are expected to be in the financial position to fund digester development.

Third Party Developer Assistance

Third party developers can be expected to be important for the development of future on-farm or community digester facilities within the Central Valley. As discussed above, most dairy farmers are likely to be unwilling or unable to develop manure digesters systems themselves. Third party developers will likely be better able to collect and manage the investment and have the expertise necessary for effective digester development. The ability for third party developers to negotiate and manage favorable Small Renewable Generator Power Purchase Agreements (PPAs) with utility companies is also likely to be a key advantage for future digester system development.

The commercial interest rates and the related return on investment (ROI) sought by private developers will be important determinants of the economic viability and future development of digester facilities in the Central Valley. The ROI that developers will apply to digester systems will be a function of both commercial interest rates and the profit and risk premiums associated with any digester facility venture. The risk facing developers can be reduced by favorable market conditions (e.g., long term contracts with utilities or other biogas/biomethane consumers) and will also be related the supply
conditions (such as the extent that the production technology and equipment is well established, widely adopted and/or transferrable to other commercial uses).

Due to the technological, market and regulatory risks associated with biogas/biomethane production, the returns on investment that potential venture capitalist or other third party developer will seek from any digester investment will initially be significantly above the returns required for other more established industries or businesses. Within the energy industry, potential investors typically seek payback periods of three to five years (Cheremisinoff, 2010; Best 2010). Within the published digester feasibility studies, the payback periods and return on investment rates applied vary considerably – partly given the differences between financial feasibility analyses (reflecting commercial investors’ profit requirements and capital terms) and economic feasibility studies (that represent agency or public policy perspectives) where the cost of money will be substantially lower and profit earning not applicable. Recent analyses for the California Energy Commission have applied rate of return estimates of 17% for their feasibility analyses (PERI, 2008).

While third party developer participation may be an important component of widespread digester development, their participation is fundamentally a reflection of the economic feasibility of dairy manure digesters and market context. Consequently, they may be considered to play an major role but will be an indirect economic driver since it will be the fundamentals of other market conditions that will determine the role and extent of their participation in the future digester development within the Central Valley.

Environment Compliance and Regulatory Requirements

In general, dairy operators face increasingly stringent state environmental regulations requiring dairy operators to adopt more advanced methods to manage their operations. The requirements of Senate Bill (SB) 700, San Joaquin Valley Air Quality Management District (SJAQMD) air quality regulations and Central Valley Water Board (CVWB) waste discharge regulations are examples of such rules. Anaerobic digesters, composting systems and other more costly waste management approaches are replacing traditional land application of dairy manure as accepted manure management practices. Consequently, if the economic returns of digester systems can be improved, then their greater implementation can be encouraged, which in turn will result in overall reduced air and water quality impacts.

Water Quality Compliance

Until relatively recently, most dairies located within the Central Valley Water Board jurisdiction operated under a waiver of waste discharge requirements. In May 2007, the Central Valley Water Board adopted Order No. R5-2007-0035 (Waste Discharge Requirements General Order for Existing Milk Cow Dairies). The order serves as general waste discharge requirements for discharges of waste from existing milk cow dairies and requires dairies to submit a Report of Waste Discharge prior to construction of an anaerobic digester.
The additional water quality requirements in the order have added considerable costs and restrictions. Farmers are now required to manage their applications of nutrients to their farmlands and otherwise protect their groundwater resources. The key water quality concerns for dairy digester systems are the potential for adverse groundwater impacts from dairy waste or digestate stored within farm lagoon systems and the added salt and nitrates from the importation of co-digester feedstock. The CVWB estimates that a typical 1,000 herd dairy produces approximately 3,600 tons (dry weight) of manure per year containing 180 tons of nitrogen and 235 tons of inorganic salts (CVWB, 2007).

Under the current process, unless landowners can prove that their farm’s specific site conditions will not result in water quality impacts, the primary compliance approach will be construction of more expensive Tier 1 lagoon systems, which is a significant barrier to widespread digester development. Currently, the CVWB is in the process of completing a comprehensive salinity management program with the State Water Board to address salinity problems within the Central Valley. However, until the new plan and program is completed, there are no general salt standards. Consequently review of dairy farm waste discharge compliance plans are performed on a case by case basis and the salt impacts of co-digester digestate are poorly understood, making it more difficult and costly for dairy farmers to comply with the water quality requirements. In addition, the Program EIR also provides an opportunity to determine if there is a more streamlined and cost-effective process for making improvements to existing dairies by adding digesters (likely for manure-only digesters; co-digestion will likely require detailed, location-specific analysis), if it is determined that widespread digester development would be beneficial from a CEQA standpoint.

Depending on the specific soil and groundwater conditions, some farms are required to install doubled lined lagoons (e.g., Tier 1) and/or reduce their application rates of liquid digestate or solid manure to comply with the state regulations. Salt accumulation issues within the Central Valley are likely to persist and there are currently limited management options for reducing the potential water quality impacts associated with accumulated salts.

Current regulatory differences between dairy and non-dairy farms also limit the ability for dairy farmers to export their manure or digestate to neighboring farms. While exportation of solid manure and/or digestate to other farms is permitted with little water quality regulatory oversight, a similar transfer of digestate effluent requires the recipient farm to comply with the WDR manure management testing and verification procedures. Although the recipient farmer could beneficially use the effluent to meet its fertilizer needs, faced with the regulatory requirements many farmers will instead elect to purchase and apply chemical fertilizer. The resulting outcome adds new nitrates locally (i.e., from the chemical fertilizer use) and reduces the options for manure digester operators to manage their nitrate load. In particular, wet system digesters (e.g., covered lagoons) that can not use all their digestate on site will likely have to reduce the water content of their effluent if the dairy farmer needs to export some of the material to meet the water quality standards. In which case, for the farmer to make the off-site transfer it will face added costs, energy use and water losses. Such offsite liquid digestate transfer issues could potentially be an even more significant regulatory issue for a community digester or co-digester operation (Martin, P., 2010).

31 Central Valley Salinity Alternatives for Long-Term Sustainability (CV-SALTS)
Air Quality
The California Air Resources Board (CARB) is responsible for regulating air emissions within the state. CARB is the lead agency for implementing the AB32 Scoping Plan which is the action plan for California to reduce it greenhouse gas emission substantially by 2020 with additional reduction by 2050. California farms were generally exempted from air quality regulations until the enactment of SB700 in 2003, which required most dairy farmers and other large confined animal feeding operations (CAFO) to obtain air quality permits for their operations from their local air district. Although rules vary between air districts, dairies that require air permits are now generally treated like other industries.

The San Joaquin Valley Air Pollution Control District has implemented several rules that apply to dairy operations including Rule 4550 (Conservation Management Practices [CMO] Plans), and Rule 4570 (Confined Animal Facilities). In the SJVAPCD new and modified dairies are subject to the New Source Review Rule – District Rule 2201, which requires Best Available Control Technology (BACT), Public Notice, Health Risk Assessment (HRA) & Ambient Air Quality Analyses (AAQA). For the SJVAPCD to issues permits, the projects are also required to comply with the California Environmental Quality Act (CEQA).

While the dairies are adapting to the new rules, the New Source Review Rule BACT requirements for NOx and SOx emissions from electrical generation equipment are cited as a real economic challenge for the dairies. There are several approaches to electrical generation but the systems are expensive to operate and poorly suited for dairy biogas or biomethane use.

The following is detailed updated information from Ramon Norman at the SJVAPCD describing the current requirements related to strict NOx emission limits (Norman, 2010).

“For projects proposing to generate power from biogas in the San Joaquin Valley, the main pollutants that the District is concerned about are NOx and SOx. This is because these pollutants are precursors to ozone (NOx) and particulate matter (NOx and SOx). The San Joaquin Valley Air basin will soon be classified as extreme non-attainment for the Federal 1-hour ozone standard (and the now revoked Federal 8-hour ozone) standard - the worst classification. The San Joaquin Valley Air basin is also classified as non-attainment for the Federal PM2.5 standard. Because of the air quality problems in the San Joaquin Valley and reductions in NOx are critical to the District’s attainment strategy, the District is now requiring more stringent emission controls (such as catalysts) for biogas-fired engines and evaluating alternative equipment (fuel cells, microturbines, etc.) to further reduce NOx emissions down to 0.15 g/bhp-hr (around 9-11 ppmvd @ 15% O2) or less as BACT for these operations. This BACT level has been in place for fossil fuel-fired engines in the District for a number of years but the District is just beginning to apply this BACT level to biogas-fired engines. To meet the District BACT for NOx from these installations, controls (catalysts) would need to be added to an engine or an alternate technology, such as microturbines or fuel cells, would need to be used. Because the San Joaquin Valley is classified as non-attainment for the Federal PM2.5 standard and SOx is an important precursor for PM2.5, emissions of SOx must also be minimized. To meet the District BACT for SOx from these installations, scrubbing of the gas to remove H2S (down to 50 ppmv) prior to combustion will also be required. Because the San Joaquin Valley Air District is classified as attainment for the CO Ambient Air
Quality Standard, BACT is usually not triggered for CO and engines would only be required to meet the 2,000 ppmvd CO limit from District Rule 4702.

At a minimum, any flares proposed for a digester system would need to satisfy the "Achieved in Practice" Category in the District's BACT Guidelines, which currently require a low-NOx flare with NOx emissions ≤ 0.06 lb/MMBtu. Any flares proposed for a digester would also need to satisfy the requirements of District Rule 4311, which requires enclosed flares to meet certain NOx and VOC emission limits and to be source-tested annually. Open flares (air-assisted, steam-assisted, or non-assisted) with flare gas pressure is less than 5 psig must be operated in such a manner that meets the control device requirements of 40 CFR 60.18. Emergency flares, which are exempt from the previous provisions, are required to maintain records of the duration of flaring events, the amount of gas burned, and the nature of the emergency. The requirements of District Rule 4311 can be found at the following link:


Any boilers or process heaters proposed for a digester system and rated 5.0 MMBtu/hr or greater would need to satisfy the requirements of District Rule 4320, which requires biogas-fired units to meet a NOx emission limit of 12 ppmv @ 3% O2 and also requires periodic source testing and emission monitoring. The requirements of District Rule 4320 can be found at the following link: http://www.valleyair.org/rules/currntrules/r4320.pdf.”

Mr. Norman also provided a list of suppliers of equipment that may be able to satisfy the District’s BACT requirement for NOx from power generating equipment that combusts biogas (Norman, 2010).

**Inter-Agency Co-operation and Co-ordination**

Fundamentally, there is a major challenge for finding a mechanism and forum for facilitating inter-agency co-operation and co-ordination. From a comprehensive cross resource perspective, manure digesters are generally recognized to offer significant net environmental benefits. However, since these benefits extend across several resource areas (i.e., air, water and energy use) and are not fully recognized by market mechanisms (e.g., odor and greenhouse gas reductions) balancing impact tradeoffs remains difficult. Currently methane emissions from dairy operations are not regulated.

As a result, while the negative air quality impacts of the NOx emissions are recognized, the corresponding (albeit different and less localized) air quality benefits of the methane destruction are not. Furthermore, there is not an easy mechanism for valuing the societal tradeoff of the beneficial energy capture (i.e., the produced electricity) from a resource that otherwise would have its entire energy resource value lost.

The complicated regulatory environment facing dairy operators is widely considered to be a major obstacle to future anaerobic digester development within the Central Valley. Several industry participants and analyses recommend that continued CEC and CPUC support to address technical and commercial risks is important for future development of manure digester systems in the Central Valley (Dusault, 2010). Improvement to the permitting process for complex projects with cross resource impacts such as anaerobic digesters is generally recognized as important and necessary for encouraging future development of manure digesters. A centralized and streamlined permit process that reduces the regulatory burden would greatly facilitate future dairy digester development.
Other Benefits of Dairy Digester

Talk about economic benefits to Central Valley in terms of overall investment and job creation (construction and O&M). $1 billion of potential investment directly into the Central Valley, and thousands of jobs.

Keep energy dollars in-state

Increase tax rolls

Utility Cooperation

There is currently some mismatch between utilities interests and needs for digester development. Although there are some regulatory restrictions to utilities, there are many potential opportunities for a supportive utility role to bridge the existing market gaps and barriers to digester development. Support by utilities in this early stage of market development could have a significant positive role.[[[[[[this point on SoCalGas was moved down a couple paragraphs]]]]]]

Several experts suggested that the market for future biogas conversion to biomethane would be improved if utilities such as PG&E were willing to invest, operate and maintain the necessary upgrading facilities required for pipeline injection. While such an approach would reduce the technical and investment burden on third party or dairy digester owners, the significant production costs for pipeline injection would remain high as only minimal savings would be potentially gained by reducing the utility need for verification of the non-utility injected biomethane quality.32 In addition, the location constraints of biogas acquisition in relative proximity to the utility transmission system would also remain.

Under the current market and regulatory conditions, there is little incentive for PG&E or other utilities to assume the additional costs, risks and responsibilities. Indeed, it may be expected that CPUC approval would be necessary for PG&E to undertake any such biogas development projects and pass on the costs to ratepayers. SoCalGas, however, is investigating the feasibility of potential cooperation and involvement in future biomethane production projects for pipeline injection with Sempra Energy (Goodman, 2010).

Digester projects pursuing electricity generation have also been encountering obstacles associated with the interconnection process. Digester projects applying for interconnects in conjunction with the feed-in-tariff, which provides for a first-track interconnection procedure, have been encountering months of delays and substantial additional costs. Expedited interconnection procedures at the lowest possible costs, in the most standardized manner achievable, would be of great benefit to widespread digester deployment.

32 It is likely that the utility would nonetheless need to evaluate biogas quality
Emerging Technologies and Market

As discussed above, the economic viability of future digester development appears currently to be primarily constrained by the comparatively low commodity prices for natural gas and electricity coupled by the relatively high costs of production. The complicated and cross resource impacts associated with dairy digester systems result in costly compliance requirements. Unless major breakthrough technological improvements are achieved, it is considered likely that manure digester production will remain economically unfeasible without government support for the foreseeable future. Furthermore, future improvements in feasibility would be expected to be minimal and incremental as long as natural gas and electrical prices remain relatively stable in real terms.

There is considerable hope within the renewable resource industry that fuel cells, “micro-scrubbers,” or other new technological improvements may be possible that could reduce unit production costs for biogas and/or biomethane production or enable affordable on-site electrical production that complies with air quality requirements.

Similarly, the economic feasibility for biogas production is presently reduced by the currently limited market for CBM and LBM as a transportation biofuel. Major growth in commercial and/or consumer natural gas vehicles (and the necessary related fueling infrastructure) would likely represent a new market and demand for CBM and/or LBM. In which case, dairy manure production of CBM and/or LBM might be able to take advantage of some comparative advantage of local production (especially over LBM will currently is mostly imported into California at some cost either by road or rail). However, until these biofuel markets develop or other major technical advances actually occur, the economic feasibility of dairy manure digesters can be expected to remain difficult without adequate governmental and/or regulatory assistance.

Analysis Caveats

The previous economic assessment is based on research and interviews during a highly dynamic period for the digester and other renewable energy industries. As outlined above, there are many unknown variables facing the industry – both technological and regulatory. Consequently, quantitative analysis of the industry economics is particularly challenging and, if imbedded assumptions or factors are not recognized, any finding can be misleading or highly prone to misinterpretation.

Furthermore, most digester analyses are very site and technology-specific. In addition, most operating digester projects have been pilot or demonstration projects that have received considerable government assistance. As a result, there is extensive complexity associated with any efforts to normalize the design, costs and performance of digesters operating under very different circumstances.

Consequently, we have used a predominantly qualitative approach since the primary purpose for this economic assessment has been to provide a framework by which the key economic drivers can be distinguished from the numerous variables and other factors that have a more indirect and lesser contribution to dairy digester feasibility.

33 However, successful development of the proposed Clearwater and/or Port Esperanza LNG terminals in Southern California would be expected to reduce the potential locational advantage for future LBM production.
References


CH2M Hill, Making Renewables Part of an Affordable and Diverse Electric System in California, 2007.


Clear Horizons, Craven Brothers Farm Digester Project Feasibility Study, January 2006.


Key Factors Determining Economic Feasibility


LaMendola, T. Personal Communication, April 2010.


Norman, Ramon, Air Quality Engineer, email to Tim Morgan at ESA, February 4, 2010.


Acronyms

AB  Assemble Bill
ACEEE  American Council for an Energy Efficient Economy
BACT  Best Available Control Technology
CAFO  Confined Animal Feeding Operations
CARB  California Air Resources Board
CBG  Compressed Biogas
CCAR  California Climate Action Registry
CEC  California Energy Commission
CHP  Combined Heat and Power
CNG  Compressed Natural Gas
DG  Distributed Generation
ERB  Emerging Renewables Program
GHG  Greenhouse Gas
IC  Internal Combustion
IEUA  Inland Empire Utilities Agency
LCFS  California Low Carbon Fuel Standard
LBM  Liquefied Biogas
LNG  Liquefied Natural Gas
MPR  Market Price Referent
NCRS  Natural Resource Conservation Service
PIER  Public Interest Energy Research Program
PPA  Power Purchase Agreement
ppm  Parts per million
PSA  Pressure Swing Absorption
REC  Renewable Energy Credits
RPS  Renewable Portfolio Standards
TAG  Technical Advisory Group
WDR  Waste Discharge Requirements

Glossary

Aerobic Bacteria  Bacteria that require free elemental oxygen to sustain life.
Aerobic  Requiring, or not destroyed by, the presence of free elemental oxygen.
AgSTAR  A voluntary federal program that encourages the use of effective technologies to capture methane gas, generated from the decomposition of animal manure, for use as an energy resource.
Anaerobic  Requiring, or not destroyed by, the absence of air or free oxygen.
Anaerobic Bacteria  Bacteria that only grow in the absence of free elemental oxygen.
Anaerobic Lagoon  A treatment or stabilization process that involves retention under anaerobic conditions.
Anaerobic  A tank or other vessel for the decomposition of organic matter in the absence of elemental oxygen.
Anaerobic Digestion  The degradation of organic matter including manure brought about through the action of microorganisms in the absence of elemental oxygen.
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Best Management Practice (BMP)</td>
<td>A practice or combination of practices found to be the most effective, practicable (including economic and institutional considerations) means of preventing or reducing the amount of pollution generated by nonpoint sources to a level compatible with water quality goals.</td>
</tr>
<tr>
<td>Biogas</td>
<td>Gas resulting from the decomposition of organic matter under anaerobic conditions. The principal constituents are methane and carbon dioxide.</td>
</tr>
<tr>
<td>Biomass</td>
<td>Plant materials and animal wastes used especially as a source of fuel.</td>
</tr>
<tr>
<td>British Thermal Unit (BTU)</td>
<td>The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. One cubic foot of biogas typically contains about 600 to 800 BTUs of heat energy. By comparison, one cubic foot of natural gas contains about 1,000 BTUs.</td>
</tr>
<tr>
<td>Carbon Offset (Carbon Credit)</td>
<td>A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” i.e. the offset provider must prove that the project would not have happened without its financial investment, and that the project goes beyond “business as usual” activity.</td>
</tr>
<tr>
<td>Complete Mix Digester</td>
<td>A controlled temperature, constant volume, mechanically mixed vessel designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.</td>
</tr>
<tr>
<td>Composting</td>
<td>The biological decomposition and stabilization of organic matter under conditions which allow the development of elevated temperatures as the result of biologically produced heat. When complete, the final product is sufficiently stable for storage and application to land without adverse environmental effects.</td>
</tr>
<tr>
<td>Covered Lagoon Digester</td>
<td>An anaerobic lagoon fitted with an impermeable, gas- and air-tight cover designed to capture biogas resulting from the decomposition of manure.</td>
</tr>
<tr>
<td>Demand charge</td>
<td>The peak KW demand during any quarter hour interval multiplied by the demand charge rate.</td>
</tr>
<tr>
<td>Digestate</td>
<td>The sludge or spent slurry discharged from a digester. In this report digestate generally refers to the dewatered solids portion of the spent slurry, rather than the liquid digestate, which is referred to as the effluent.</td>
</tr>
<tr>
<td>Digester</td>
<td>A concrete vessel used for the biological, physical, or chemical breakdown of livestock and poultry manure.</td>
</tr>
<tr>
<td>Discount rate</td>
<td>The interest rate used to convert future payments into present values.</td>
</tr>
<tr>
<td>Down payment</td>
<td>The initial amount paid at the time of purchase or construction expressed as a percent of the total initial cost.</td>
</tr>
<tr>
<td>Drystack</td>
<td>Solid or dry manure that is scraped from a barn, feedlane, drylot or other similar surface and stored in a pile until it can be utilized.</td>
</tr>
<tr>
<td>Effluent</td>
<td>The discharge from an anaerobic digester or other manure stabilization process.</td>
</tr>
<tr>
<td>Energy Charge</td>
<td>The energy charge rate times the total kWh of electricity used.</td>
</tr>
<tr>
<td>Fats</td>
<td>Any of numerous compounds of carbon, hydrogen, and oxygen that are glycerides of fatty acids, the chief constituents of plant and animal fat, and a major class of energy-rich food. “Fats are a principal source of energy in animal feeds and are excreted if not utilized.”</td>
</tr>
<tr>
<td>Fixed Film Digester</td>
<td>An anaerobic digester in which the microorganisms responsible for waste stabilization and biogas production are attached to some inert medium.</td>
</tr>
<tr>
<td>Flushing System</td>
<td>A manure collection system that collects and transports manure using water.</td>
</tr>
<tr>
<td>Greenhouse Gas</td>
<td>An atmospheric gas, which is transparent to incoming solar radiation but absorbs the infrared radiation emitted by the Earth’s surface. The principal greenhouse gases are carbon dioxide, methane, and CFCs.</td>
</tr>
<tr>
<td>Hydraulic Retention Time (HRT)</td>
<td>The average length of time any particle of manure remains in a manure treatment or storage structure. The HRT is an important design parameter for treatment lagoons, covered lagoon digesters, complete mix digesters, and plug flow digesters.</td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>The annual rate of increase in costs or sales prices in percent.</td>
</tr>
<tr>
<td>Influent</td>
<td>The flow into an anaerobic digester or other manure stabilization process.</td>
</tr>
</tbody>
</table>
### Key Factors Determining Economic Feasibility

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Internal Rate of Return</td>
<td>The discount rate that makes the NPV of an income stream equal to zero.</td>
</tr>
<tr>
<td>Kilowatt (kW)</td>
<td>One thousand watts (1.341 horsepower).</td>
</tr>
<tr>
<td>Kilowatt Hour (kWh)</td>
<td>A unit of work or energy equal to that expended by one kilowatt in one hour or to 3.6 million joules. A unit of work or energy equal to that expended by one kilowatt in one hour (1.341 horsepower-hours).</td>
</tr>
<tr>
<td>Lagoon</td>
<td>Any large holding or detention pond, usually with earthen dikes, used to contain wastewater while sedimentation and biological treatment or stabilization occur.</td>
</tr>
<tr>
<td>Land Application</td>
<td>Application of manure to land for reuse of the nutrients and organic matter for their fertilizer value.</td>
</tr>
<tr>
<td>Liquid Manure</td>
<td>Manure having a total solids content of no more than five percent.</td>
</tr>
<tr>
<td>Loading Rate</td>
<td>A measure of the rate of volatile solids (VS) entry into a manure management facility with methane recovery. Loading rate is often expressed as pounds of VS/1000 cubic feet.</td>
</tr>
<tr>
<td>Loan Rate</td>
<td>The percent of the total loan amount paid per year.</td>
</tr>
<tr>
<td>Methane</td>
<td>A colorless, odorless, flammable gaseous hydrocarbon that is a product of the decomposition of organic matter. Methane is a major greenhouse gas. Methane is also the principal component of natural gas.</td>
</tr>
<tr>
<td>Minimum Treatment Volume</td>
<td>The minimum volume necessary for the design HRT or loading rate.</td>
</tr>
<tr>
<td>Mix Tank</td>
<td>A control point where manure is collected and added to water or dry manure to achieve the required solids content for a complete mix or plug flow digester.</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>A combustible mixture of methane and other hydrocarbons used chiefly as a fuel.</td>
</tr>
<tr>
<td>Net Present Value (NPV)</td>
<td>The present value of all cash inflows and outflows of a project at a given discount rate over the life of the project.</td>
</tr>
<tr>
<td>NPV Payback</td>
<td>The number of years it takes to pay back the capital cost of a project calculated with discounted future revenues and costs. Profitable projects will have an NPV Payback value less than or equal to the lifetime of the project.</td>
</tr>
<tr>
<td>Operating Volume</td>
<td>The volume of the lagoon needed to hold and treat the manure influent and the rain-evap volume.</td>
</tr>
<tr>
<td>Payback Years</td>
<td>The number of years it takes to pay back the capital cost of a project.</td>
</tr>
<tr>
<td>Plug Flow Digester</td>
<td>A constant volume, flow-through, controlled temperature biological treatment unit designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.</td>
</tr>
<tr>
<td>Point Source Pollution</td>
<td>Pollution entering a water body from a discrete conveyance such as a pipe or ditch.</td>
</tr>
<tr>
<td>Process Water</td>
<td>Water used in the normal operation of a livestock farm. Process water includes all sources of water that may need to be managed in the farm’s manure management system.</td>
</tr>
<tr>
<td>Proteins</td>
<td>Any of numerous naturally occurring extremely complex combinations of amino acids containing the elements carbon, hydrogen, nitrogen, and oxygen. Proteins are in animal feeds are utilized for growth, reproduction, and lactation and are excreted if not utilized.</td>
</tr>
<tr>
<td>Renewable Energy Credits (RECs)</td>
<td>Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.</td>
</tr>
<tr>
<td>Scrape System</td>
<td>Collection method that uses a mechanical or other device to regularly remove manure from barns, confine buildings, drylots, or other similar areas where manure is deposited.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
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<tr>
<td>Simple Payback</td>
<td>The number of years it takes to pay back the capital cost of a project calculated without discounting future revenues or costs.</td>
</tr>
<tr>
<td>Slurry (Semi-solid) Manure</td>
<td>Manure having a total solids content between five and ten percent.</td>
</tr>
<tr>
<td>Solids Manure</td>
<td>Manure having a total solids content exceeding 10 percent.</td>
</tr>
<tr>
<td>Storage Pond</td>
<td>An earthen basin designed to store manure and wastewater until it can be utilized. Storage ponds are not designed to treat manure.</td>
</tr>
<tr>
<td>Storage Tank:</td>
<td>A concrete or metal tank designed to store manure and wastewater until it can be utilized. Storage tanks are not designed to treat manure.</td>
</tr>
<tr>
<td>Straight-Line Depreciation</td>
<td>Depreciation per year equals the total facility cost divided by the years of depreciation (usually the facility lifetime).</td>
</tr>
<tr>
<td>Supplemental Heat</td>
<td>Additional heat added to complete mix and plug flow digester to maintain a constant operating temperature at which maximum biological treatment may occur.</td>
</tr>
<tr>
<td>Technical Advisory Group (TAG)</td>
<td>A working group of individual representing several California State Agencies and companies knowledgeable and interested in the Environmental Impact Report (EIR) being prepared for Dairy Manure Digester and Co-digester Facilities. The group is scheduled for four meetings and will review various background documents that will help to support the preparation of the EIR.</td>
</tr>
<tr>
<td>Thermophilic</td>
<td>Operationally between 110°F and 140°F (43°C and 60°C).</td>
</tr>
<tr>
<td>Total Solids</td>
<td>The sum of dissolved and suspended solids usually expressed as a concentration or percentage on a wet basis.</td>
</tr>
<tr>
<td>Utility Interconnection</td>
<td>The method of utilizing electricity produced from manure management facilities. Options include either (1) on farm first use then sale to utility or (2) sale to the utility then direct purchase.</td>
</tr>
<tr>
<td>Volatile Solids</td>
<td>The fraction of total solids that is comprised primarily of organic matter.</td>
</tr>
<tr>
<td>Volatilization</td>
<td>The loss of a dissolved gas, such as ammonia, from solution.</td>
</tr>
<tr>
<td>Volumetric Loading Rate</td>
<td>The rate of addition per unit of system volume per unit time. Usually expressed as pounds of volatile solids per 1,000 cubic feet per day for biogas production systems.</td>
</tr>
</tbody>
</table>
Re: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Paul Miller

From: Paul Miller [PMiller@esassoc.com]
Sent: Saturday, June 26, 2010 10:18 AM
To: miller.p@sbcglobal.net
Subject: FW: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report
Attachments: CalBio_PEIR_NAC 209481 Dairy Digester Feasibility_20100430.doc

Jennifer Tencati

Sent: Tuesday, May 4, 2010 4:05 PM
To: Paul Miller
Subject: FW: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Hi Paul,
Below and attached, please comments for the Economic Feasibility report from Jackson Lehr, California Bioenergy. Please share with Nik and other team members, as needed.
Thank you,
Jennifer

Jackson Lehr

Sent: Monday, May 03, 2010 11:30 AM
To: Jennifer Tencati
Cc: nblack@calbioenergy.com; 'N Ross Buckenham'
Subject: Re: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Jennifer,
We also noticed a couple minor errors in the column headings for Table 2, “Capital Costs for Dairy Digester Developments in California.”
1. The Annual Energy Production numbers appear to be in MWh not kWh.
2. The Capital Costs should be labeled ($/kW) as opposed to ($/kWh).

Thanks again.
Jackson

On 4/30/10 9:10 PM, "Jackson Lehr" <jlehr@calbioenergy.com> wrote:

Jennifer,

Please find attached a markup of the document with suggestions from the California Bioenergy (CalBio) team. The document was already very impressive in its original form, and we hope our suggestions will help provide some additional facts to make the document as accurate as possible and to highlight some of the most pressing barriers to widespread digester development (which ultimately is a question of economic viability, the very subject of this document).

We would be happy to make ourselves available next week if Nik has any questions or would like to discuss any of our suggestions.

Thank you for all of your help with the TAG efforts.

6/26/2010
Have a nice weekend!

Best wishes,
Jackson

---

Jackson Lehr
VP, Environment & Development
California Bioenergy, LLC
646.278.9109 direct
jlehr@calbioenergy.com
www.calbioenergy.com

On 4/27/10 3:33 PM, "Jennifer Tencati" <j.tencati@circlepoint.com> wrote:

Hi Ross,

Thank you for taking the time to review the document and develop comments. Please send the comments to me and I will make sure that the appropriate team members receive a copy. We are asking for comments by the end of the week – sounds like that is in line with your timing.

Nik Carlson, ESA, is the lead for this document. If you could please provide a few day/time options that you would be available to review your comments (early next week), I would be happy to coordinate a call with Nik and other team members that should be included.

-Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

455 Capitol Mall, Suite 802
Sacramento, CA 95814-4427
www.circlepoint.com

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Please think of the environment before you print this email.

From: N Ross Buckenham [mailto:rbuckenham@calbioenergy.com]
Sent: Monday, April 26, 2010 9:13 AM
To: Jennifer Tencati
Cc: jlehr@calbioenergy.com; nblack@calbioenergy.com
Subject: RE: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Jennifer

6/26/2010
Thanks very much for sending this document.

We will listen into the CPUC meeting and their comments this AM and then work on our comments hopefully completing this week. Is that time frame ok with you?

Who is the author of this document and could we do a walk through over the phone of our comments with him/her?

Regards

Ross

---

N. Ross Buckenham
California Bioenergy, LLC
office: 214-849-9886
mobile: 214-906-9359

---

From: Jennifer Tencati [mailto:j.tencati@circlepoint.com]
Sent: Friday, April 23, 2010 7:13 PM
To: 'N Ross Buckenham'
Subject: RE: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Hi Ross,

Attached is a Word document version. If you don’t mind, we ask that you not distribute this version, but are happy to share it with you to help facilitate capturing your edits. Please let me know if you have any questions.

-Jennifer

---

From: N Ross Buckenham [mailto:rbuckenham@calbioenergy.com]
Sent: Friday, April 23, 2010 4:45 PM
To: Jennifer Tencati
Subject: RE: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Is there a word version that could be edited with tracking on and returned to you with comments.

---

From: Jennifer Tencati [mailto:j.tencati@circlepoint.com]
Sent: Friday, April 23, 2010 6:04 PM
To: Jennifer Tencati
Cc: 'Paul Miller'; 'Stephen Klein'
Subject: Dairy Digester Monday 4/26 Call re Draft Economic Feasibility Report

Dear TAG members,

---

6/26/2010
In follow up to our third TAG meeting today, we have arranged for a call in number for the 10:30 a.m. call on Monday, April 26th to discuss the Administrative Draft Economic Feasibility report (attached).

The call in number is: (605) 475-4900
ID number: 501775#

You may also join the meeting in person. It will be held at CPUC's San Francisco office at 505 Van Ness Avenue in the Golden Gate Room.
You may enter the building on Golden Gate Avenue, next to the ATM machine and go directly to the Golden Gate Room.
Parking is available on the street (metered) or at a lot on Golden Gate and Franklin (Franklin is a one way street) or Opera Plaza across from CPUC.

If you need to contact CPUC in the morning, please call Eugene Cadenasso at (415) 703-1214.

If you have questions or comments about the report or other elements of the project, please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x131.

-Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

455 Capitol Mall, Suite 802
Sacramento, CA  95814-4427
www.circlepoint.com

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Please think of the environment before you print this email.
Nik,

These are some additional edits to the Economic Feasibility report. Please let me know if you have any questions.

Eugene
703-1214
Additional CPUC edits to Dairy Digester Economic Feasibility Study

General comment:
Maps
It may be useful to the reader if the study included maps showing the general location of PG&E’s and SoCalGas’ major pipelines. The utilities should be able to provide you with such maps.

Report edits:

(A) Role of Utilities p. 2
For gas procurement for core (primarily residential and small commercial end users) customers, utilities are not necessarily restricted with regard to the price they pay for the gas. However, for core procurement, the utilities are subject to CPUC incentive mechanisms aimed at ensuring that gas is procured on a least-cost basis.

(B) Biomethane storage p. 10
Rather than saying biomethane is a more “valuable” energy commodity due to its storage capability. It may be more appropriate to say that an advantage of producing biomethane is that it may be stored and used at a later date when it can be put to its highest and best use. However, if the biomethane is being sold at a fixed price rather than on the spot market, price arbitrage opportunities for using storage is non-existent. It should be mentioned that the producer may incur additional costs to store (e.g., need for storage facilities) the biomethane as well.

(C) CPUC also approved Microgy contract in addition to Vintage p. 10
However, to meet contractual obligations biomethane can be nominated from Texas through a later contract amendment. These are the CPUC resolutions.
http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/91790.pdf
http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/71830.pdf

It may be instructive to talk to Microgy about “lessons learned”.

This is the Vintage CPUC resolution:
http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/68429.pdf

(D) CARB LCFS p.11
CARB Low Carbon Fuel Standard could be a factor to spur the use of biogas/biomethane for transportation uses with the possibility of some government funding. See p. II – 13:
The Commission is considering extending the ClimateSmart program through 2011.

(F) Biogas upgrading p. 25
This is link to biomethane quality specifications for the delivery of gas into SoCalGas’ system:

(G) Distribution/Transmission system p. 26
In addition to pipeline constructions costs, there are also possible land acquisition costs.

(H) Pipeline injection p. 27
In 2008, SoCalGas and SDG&E requested CPUC permission to allow the recovery of biomethane project interconnection costs to be recovered from all ratepayers. The CPUC denied this request with out prejudice on procedural grounds in Resolution G-3420. The utilities may file an application for further CPUC consideration of this proposal.
http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/91214.PDF
(I) Environmental Compliance and Regulatory Requirements p. 32

Include potential CARB AB 32 regulations:

(CARB) AB 32 Scoping Plan
CARB’s AB 32 Scoping Plan identifies methane capture at large dairies as a recommended action to mitigate GHGs. The Plan provides some general information about dairy digester costs. See pp. C-194-5 at:


(J) Utility cooperation P. 36

Another potential benefit of utility involvement may be the utilities ability to exercise the right of eminent domain to acquire right-of-way needed for pipeline construction. This could possibly be used to get access to utility pipeline interconnection points.
Hi Paul,

This comment on the Feasibility report just came in from Jeff Reed, Southern California Gas Comp and SDG&E.

-Jennifer

Jennifer:

Sorry this is late -- the e-mail came back undeliverable and it took me a while to sort out the error in your address. Please confirm that you get this.

The attached document contains preliminary comments and edits from Southern California Gas Company and SDG&E on the draft feasibility report. Comments and edits are provided only on the discussion of market price for biomethane, the role of utilities and specific references to SoCalGas. We would also comment that we believe a more rigorous analysis is needed to accurately assess the economics of dairy clusters and co-digestion projects interconnecting with the gas pipeline system.

Regards,

Jeff
KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Prepared for the
California Regional Water Quality Control Board, Central Valley Region

April 2010
KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Prepared for the California Regional Water Quality Control Board, Central Valley Region

April 2010

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Olympia
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Appendix A-192
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Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-digester Facilities

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KEY FACTORS DETERMINING ECONOMIC FEASIBILITY OF DAIRY MANURE DIGESTER AND CO-DIGESTER FACILITIES

Executive Summary

Extensive research and review was conducted on published industry analyses on anaerobic digestion and the use of dairy manure for bioenergy within California and elsewhere within the United States. Numerous factors are identified as key contributors influencing the future economic viability of the potential development of dairy manure digesters and co-digesters within the Central Valley. The factors determined to be important economic drivers (both positive and negative) are summarized below:

- **Energy Prices.** Most fundamentally, current and projected future commodity prices of natural gas and electricity are critical revenue constraints for dairy digesters. Natural gas is a readily available substitute for dairy digester produced biogas and biomethane. Consequently, most potential customers will be unlikely to buy biogas or biomethane at prices much above their commodity price for natural gas. Similarly, the value of biogas generated electricity will be limited by the prices of utility supplied power alternatives. Currently, long term natural gas and electricity prices are not forecast to increase (adjusted for inflation) due to recent discoveries of new domestic shale gas reserves. Consequently, biogas can not expect substantially improved feasibility from future commodity price escalation.

- **Air Quality Regulation of On-site Electrical Generation.** On-site generation of electricity represents a potential direct, “lower tech” and inexpensive beneficial use option for biogas. However, air quality restrictions within the Central Valley may preclude this use. If cost effective compliance technologies or mitigation can be developed, digester systems could be greatly enhanced – especially if adequate feed-in tariffs or other utility support increases the revenue potential for small scale distributed energy production.

- **Public Sector Support.** Federal and state grant funding, low interest loans and other public sector support (e.g., tax incentives and pilot programs) have played a vital role in past digester development. Both the amount and form of future public sector support can have a strong positive role in fostering manure digester implementation within the Central Valley. Future government support is expected to remain essential for continued development of manure digester systems.

- **Access to Capital and Third Party Developers.** The current financial difficulties facing most dairy farmers and the generally tight credit market will ensure that funding for digester developments will be scarce and costly for the foreseeable future. While increased participation by third party developers may provide some technical and financial assistance, private capital...
will be relatively costly. The potential “capital crunch” constraints will be especially acute for those biomethane production projects that require major construction, involve new technical applications and/or supply biomethane to less established and developing non-utility markets.

- **Biogas Upgrading for Biomethane Production.** Biogas scrubbing and conditioning for biomethane production is currently costly and can only be cost effectively performed at production levels significantly greater than most individual dairy operations can support. Combined with biogas upgrade system costs, system design and location requirements represent key factors limiting the feasibility of digester biogas sales for the foreseeable future.

- **Role of Utilities.** Local utilities represent a key potential customer for surplus energy production from dairy digesters. Local utilities are the predominant energy producers and wholesalers in the market and therefore can most effectively and efficiently manage the sale, distribution and use of digester produced energy. Currently, utilities are understandably wary of such distributed energy projects since they represent emerging competition. In general, the administration of small scale production (from dairy digesters) provides limited financial return for utilities. Utilities also face regulatory restrictions that limit both their involvement and, most importantly, the prices that they can pay for dairy digester energy. However, innovative and constructive partnerships between digesters and utilities offer a key potential mechanism for greater and more cost-effective development of biogas as a renewable resource.

- **Technological Change.** Although many of the core digester and biomethane technologies are fairly well established, future commercialization of dairy manure digester systems may be expected to result in some cost effectiveness improvements. However, currently most foreseeable improvements appear to be incremental rather than fundamental. Consequently, most analysts suggest that per unit production costs for biomethane and related electrical generation will remain higher than commodity energy prices and hence public support for production will remain necessary. Key technology breakthroughs that could dramatically improve future dairy digester profitability include cost-effective on-site electrical generation with biogas (e.g., very low emission micro-turbines or fuel cells) or inexpensive and/or farm sized biogas upgrading systems.

- **Proximity to Feedstocks and Energy Markets.** The location of potential dairy digester and co-digester systems can be critical to the facility’s ability to obtain sufficient manure (and possibility feedstocks for co-digesters) and/or supply its biogas and other facility products to potential buyers at an attractive price.

- **Permitting.** Facility development design and permit costs to comply with state and local regulations can represent major delays, risks and financial expenses that may discourage potential digester development.

Many other factors will also contribute to the profitability of dairy digester systems. Generally, the effects of the other factors are relatively minor compared to the economic drivers identified above. For example, many analyses have investigated the potential for revenues gains from digester byproducts (e.g., digestate sales), tipping fees (for co-digester), or the environmental attributes of anaerobic digesters (renewable energy credits and carbon offsets) as important feasibility factors. However, the magnitude of these often speculative revenues will remain secondary to the value of the digester’s primary product, which is biogas.
Introduction

The technological feasibility of biogas production from manure digesters and co-digesters is well established. Generally, digester produced biogas has been used for on-site generation of electricity and/or heating to meet the farm needs. Farm digester systems typically can produce three or four times the amount of energy that their farm’s need. This surplus biogas production represents a significant renewable energy resource with considerable potential economic value and environmental benefits.

However, to understand and evaluate the economic and environmental trade-offs associated with future manure digester and co-digester systems in the Central Valley of California, the key factors determining the economic feasibility need to be determined. Three basic types of economic factors can be identified: revenue factors, cost factors and implementation/development issues.

The balance and interrelationships of these factors under the specific project circumstances will determine the project’s overall feasibility. Most simply stated, if the average revenues (i.e., on a per unit basis) are greater than the digester’s average cost of production, then the project will have a positive benefit-cost ratio and will, in a basic sense, be economically feasible. However, to fully assess the project’s feasibility, implementation factors should also be considered to determine the likelihood that successful future development can occur.

Revenue and costs naturally face tradeoffs in the project’s feasibility as increased costs are usually necessary to generate higher revenues. The key for improving a project’s feasibility occurs when the marginal revenues are greater than the marginal cost required for the revenue growth.

Each factor will have both technical and financial components determining the magnitude and nature of its effect on the system’s feasibility. Generally, economies of scale associated with greater production efficiencies will result in a lower production cost per unit.1 Similarly, at a fixed rate of production, higher sale revenues (or reduced production costs) will increase the revenues per unit. In both cases, the system’s economic feasibility will be improved.

The following analysis provides a brief description of the key factors affecting the economic feasibility of digester systems. The nature and extent of each factor’s contribution or role to the economic feasibility is also identified and evaluated. The central purpose of the analysis is to identify those economic or technological “drivers” that play a major role in determining the viability of digester system development. Expected future trends that might alter the system’s overall economic feasibility are discussed.

The analysis generally discusses manure digesters and unless explicitly noted otherwise, should be read as also applicable to and inclusive of co-digester systems. In addition the report maintains an important distinction between biogas and biomethane. Biogas is generally synonymous with raw biogas (i.e., the unrefined biogas produced by anaerobic digesters that has a methane content of 50 to 65 percent). Biomethane refers to refined biogas with higher methane content, typically 95 percent or more.

---

1 Except in cases where equipment of facility requirements or cost / revenue thresholds may result in a “step-function” cost.
Finally, it should be noted that this analysis primarily addresses “economic” feasibility issues and as such considers the general costs and benefits of manure digesters. Strictly speaking, “financial” feasibility analysis typically refers to a more specific and comprehensive determination of the revenues and expenditures for a well-defined and site specified project. As such, a financial feasibility analysis would typically provide a more detailed description and estimates of project costs and revenues, consider its business cash-flow and include greater characterization of applicable market conditions and other considerations – primarily from the perspective of the potential owner/investor. Nonetheless, financial and economic factors are often used interchangeably. Unless specified otherwise, references to financial issues will refer to a more general economic assessment of cost and revenue issues.

The economic feasibility for specific systems will depend not only on general feasibility factors but may also depend upon site- or system-specific considerations. Nonetheless, important general observations can be identified and assessed.

**Revenue Factors**

The revenues generated by a future digester are central for its economic viability. Typically, it is more difficult to estimate future revenues than it is to estimate future costs which are easier to specify. This is particularly true in the case of a new or emerging market (e.g., such as biomethane) where the potential customers and future product applications are difficult to identify and fully evaluate.

The following section provides a brief overview and assessment of the various factors that will influence the potential revenue performance of future anaerobic digester development in the Central Valley of California. When possible, the relative magnitude and any significant future revenue variables are also reported so that those factors that are current and future revenue “drivers” can be identified and their inter-relationships with cost and implementation better understood.

**Biogas Productivity**

The efficiency and effectiveness of biogas / biomethane production of manure digesters and other related production processes is a central factor in determining economic feasibility. All else being equal, greater biogas production will increase the system’s revenue potential and hence cost-effectiveness.

Currently, most dairy digester produced biogas is used on-site for energy generation. Electrical production is generally the primary use of the produced biogas although heat is frequently also produced for use in the anaerobic digester either as part of a combined heat and power system (CHP)\(^2\) or separate dedicated boiler systems. Consequently many of the feasibility studies for manure digesters report their productivity and costs in terms of the system’s electricity production.

---

\(^2\) The thermal energy recovered in a CHP system can be used for heating or cooling farm facilities. Since CHP captures the heat that would otherwise be lost in traditional electrical generation, the efficiency of an integrated system is much greater (up to 85%) than the separate systems combined efficiency (45%) (ACEEE, 2010).
Overall System-wide Estimates

There is a wide variance in the methane and electrical production rates estimated for manure power systems. The potential biogas production will not only depend on the anaerobic digestion process used but also on both the volume of biodegradable organic materials in the collected manure and the length and type of manure collection and storage used. Similarly, the amount of electricity that can be produced by the digester system will also depend on the electrical generation system used.

The California Energy Commission (CEC) conservatively estimates an average 36 cu.ft. of methane per cow\(^3\) per day (with an energy content of 36,000 Btu/day) which can generate 0.107 kWh of electricity. The EPA estimates that manure digesters can typically produce 38.5 cu.ft. of methane per cow per day (EPA, 2004).

Actual daily electrical generation performance at Hilarides Dairy was substantially less at 0.055 kWh per cow (though partly due to substantial biogas flaring during the evaluation period) (WURD, 2006). Craven Farms reported achieving daily energy values of 34,500 Btu/cow with a 0.096 kWh per cow electricity generation rate that is comparable to CEC estimates. Other studies suggest 0.14 kWh per cow (Electrigaz, 2008), and 0.1 kWh per cow (Black & Veatch, 2007) as reasonable daily electrical productivity projections. Other analysts have more optimistic estimates of the per cow energy values. PG&E has estimated that each cow may generate 1,640 kWh annually (equivalent to 0.187 kWh per cow\(^4\)).

Within these biogas production parameters, it is generally agreed that adequate biogas capacity can be attained by larger dairies for development of dairy digesters to be technically feasible, and to be potentially economically viable with sufficient revenue assistance.

Specific Digester Systems

Manure Digesters

Three primary anaerobic digester system approaches are commonly used to treat dairy manure. The system most suited for a specific dairy operation will generally depend on its manure management system. As of October 2009, 21 major anaerobic digester systems had been constructed and are currently operating within California.\(^4\) The digester systems vary from relatively small dairy farm facilities processing the manure wastes for approximately 200 head of cattle to very large dairies with up to 5,000 cattle.

- Covered lagoon systems are the most basic and traditionally the most inexpensive anaerobic digester systems to construct and operate. These systems require the manure to be highly diluted (typically with a 3% or less total solid content) roughly consistent with “flush” manure handling. Covered lagoon digesters generally are unheated (mesophilic) and are not well suited for co-digestion with other feedstock. The average retention times for processing the manure is 45 to 60 days. The biogas conversion rates for covered lagoon

\(^3\) Whenever possible, production and cost projections have been normalized for a 1,000 lb dairy cow.

\(^4\) In 2009 six operating digester systems have recently suspended or closed their operations due to financial difficulties or regulatory compliance issues.
systems are generally 35% to 45% (Burke, 2001). Covered lagoon systems are currently the most widely constructed and operated dairy digester systems in California.

- **Complete mix systems** consist of a tank constructed of either reinforced concrete or steel. The digester contents are periodically mixed and frequently heated to maintain an optimal temperature for methane production. As a result, complete mix systems are more expensive to construct and require applied energy to operate. These systems work best with slurry manure with a total solids content of 3% to 10%. As a result they can be used by managed flush manure management dairies or scrape manure dairies if water can be added to the collected manure. Complete mix systems are well suited for co-digestion and have a relatively short retention time of 15 to 20 days. Consequently they are also able to handle higher processing loads. Heated digestion (thermophilic) with a complete mix system can be expected to increase biogas conversion rates to 45% to 55% (Burke, 2001). Currently, there only a few complete mix digester systems are operating within California.

- **Plug Flow Digesters** consist of a long relatively narrow tank often built below ground. The digester requires semi-solid manure (i.e., with a total solid content between 11% and 13%) consistent with “scrape” manure management systems. Plug flow systems can be operated heated or unheated. The costs and biogas conversion rates for plug flow digesters are comparable to similar complete mix systems. Typical retention time for plug flow digesters are 20 to 30 days (Burke, 2001). Also, plug flow digesters are less well suited for co-digestion use. Currently, 6 plug flow digesters current operate or recently operated within California.

Until recently, the price performances of these three digester systems were roughly comparable. The higher biogas production from managed digester systems (i.e., complete mix and plug flow) covered the additional construction costs. As a result, the costs per cow for these systems were approximately the same (Martin, 2010). However, as result of recent imposed manure management regulations for Central Valley dairy farms, depending on their land and groundwater conditions, many farmers are required to construct more expensive Tier 1 lagoon systems. In such cases, the added costs for double lining or reinforcing the lagoons represent a significant additional cost and will make complete mix and plug flow systems more attractive and cost-effective digester systems for biogas production.

Wider adoption and commercialization of digester systems may be expected to reduce system costs and improve performance – both from facility design improvements and better system management. However, the biogas productivity improvements will be relatively limited and incremental.

**Co-digesters**

The biogas productivity of dairy manure digesters can be greatly increased by the addition of other non-manure organic feedstocks. The proportional increase in biogas production will depend on the quality and suitability of the added feedstock. Food or agricultural wastes with higher oil or grease contents will generally release a greater amount of methane than other feedstocks with lower potential energy values. There is considerable variation amongst analyses in the amount of additional methane that co-digesters can produce. A conservative analysis for the CEC observed approximately a 35% improvement in methane production by co-digestion (CH2M Hill, 2007). Other commenters suggest that high energy feedstocks (e.g. fats, oils and greases or municipal
organic wastes) could result in a doubling or even tripling of biogas production by dairy digesters (Hintz, 2010). Such industry analysts projected that the potential for major gas productivity improvements (supplemented by tipping fee revenues with longer term contracts for handling the municipal green wastes) will make a substantial improvement in the economic feasibility of biogas production (Best, 2010).

Co-digestion is more management intensive and could add greater reporting and oversight requirements to comply with water quality and solid waste regulations. However, the additional equipment costs for enhanced production should be minor (presuming the feedstock handling, preparation and storage requirements are limited). Consequently, many analysts suggest that co-digestion can provide cost effective biogas production gains.

However, availability of suitable feedstock will be important for determining the practicality and cost effectiveness of co-digestion. Many analyses identify potential tipping fee revenues for the digester operator from the feedstock sources as an important additional revenues source. However, as discussed later under the discussion of by-product revenues, most potential agricultural wastes are only seasonally available and may be located too far from specific digesters to be cost-effectively transported. Feedstocks also may become a commodity so that co-digester operators will likely have to obtain a variety of different feedstocks.

**Centralized Digester**

Only a few studies have assessed the economic feasibility of centralized digesters within the United States. Feasibility studies for centralized digester systems in New York state, southern Wisconsin and Oregon concluded that the proposed systems were uneconomical (Bothi, 2005; Reindl, 2006; DeVore, 2006). Analysis for a centralized manure digester in Dane County, Wisconsin projected significant cost efficiencies compared to individual systems but still required major public and private sector support.

A few large centralized manure digesters have been constructed and operate in the United States. The Inland Empire Utilities Agency’s (IEUA) Chino Basin project in South California was the first centralized anaerobic digester to be developed in the United States and is the only centralized digester facility currently operating in California. The IEUA project came online in 2002 and processes 225 tons of manure per day from 6,250 dairy cows, plus food waste from local food industries. The manure is trucked to the facility from six farms located within 6 miles of the digester (Davis, 2009).

However, currently all of these centralized digesters are in effect demonstration projects having received major funding assistance and have faced significant operational difficulties. The Chino Basin facility itself received approximately $5 million of its $8.5 million construction cost from the USDA’s Natural Resource Conservation Service (NCRS) for watershed protection. The CEC provided approximately $2 million in funding with the remainder provided by the Inland Empire Utilities Agency (IEUA) that owns and operates the facility. The energy generated from the biogas powers the agency’s off-site groundwater desalinization plant and wastewater facilities.

5 It is presumed that co-digestion will not substantially alter the value or use of the resulting digestate except for the negative aspects from potential net nitrate and salt increases associated with the feedstock importation to the dairy.
Large scale biomethane production requirements are a primary rationale for centralized digester systems. Although there are potential limited economies of scale for the centralized digester, manure transportation and handling costs can offset the economic savings if there are not sufficient suitable dairies willing to participate in close proximity to the proposed facility. Given the limited and geographical constraints on such facility’s economies of scale, the centralized digester systems represent a secondary factor for digesters’ economic feasibility. Currently, there are only limited future system enhancements foreseen that would improve their cost-effectiveness.

**Electrical Generation**

Electrical generation is currently the primary use of digester biogas within California. Biogas (and biomethane) can be used to generate electricity using a variety of technologies including reciprocating engines (e.g., such as internal combustion), microturbines, gas turbine and fuel cells. Electrical generation with digester gas represents a promising distributed generation (DG) technology offering not only the environmental benefits of offsetting fossil fuel use but also has the additional benefit of destroying methane which otherwise would have major greenhouse gas impacts.

Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in the determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. This emission standard has been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards.

Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, currently properly operated “clean burn” IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations (Joblin, 2010). While additional selective catalytic reduction can in some cases be used to further reduce emissions, the necessary secondary emission controls are expensive and difficult to operate on lower energy fuels such as unrefined biogas. Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 - 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the SCS-Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010).

Microturbines are a newer technology that is becoming increasingly available. While potentially well suited for low emission electrical generation using biomethane, microturbines generally do not operate well under hot climate conditions (e.g., such as during summer months within the Central Valley). Recent implementation efforts at dairy digesters have been mostly unsuccessful as

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6  Only Vintage Dairy facility near Fresno uses the majority of its biogas production for biomethane production and injection into the utility grid.

7  Distributed generation also potentially offers additional system benefits of reduced transmission line infrastructure requirements and possibly reduced peak power system capacity requirements.

8  Current microturbines cannot be used with biogas due to the effects of hydrogen sulfide impurities.
reliability issues could not be solved for on-farm uses (Dusault, 2010). Analysts also suggest that at comparable implementation scales, the thermal conversion efficiency of microturbines will typically be 5% less than internal combustion (IC) engines.

### TABLE 1
COMPARISON OF ELECTRICAL GENERATION TECHNOLOGIES FOR BIOMETHANE

<table>
<thead>
<tr>
<th>Factors</th>
<th>Microturbines</th>
<th>Combustion Turbines</th>
<th>Reciprocating Engines</th>
<th>Fuel Cell</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost ($/kW)</td>
<td>$300 - $1,000 / kW</td>
<td>$300 - $1,000 / kW</td>
<td>$300 - $900 / kW</td>
<td>$5,500 - $12,000 / kW</td>
</tr>
<tr>
<td>Commercially Available</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Only Phosphoric Acid Fuels Cells Available</td>
</tr>
<tr>
<td>Size Range</td>
<td>30-500 kW</td>
<td>500 kW – 25 MW</td>
<td>5 kW – 7 MW</td>
<td>1 kW – 10 MW</td>
</tr>
<tr>
<td>Efficiency</td>
<td>20 – 30%</td>
<td>20 – 45% (at scale)</td>
<td>25 – 45%</td>
<td>30 – 60%</td>
</tr>
<tr>
<td>Emissions</td>
<td>Low (&lt;9 – 50 ppm) NOx</td>
<td>Very Low when controls applied</td>
<td>Emission Controls Necessary for NOx CO – 50 ppm min.</td>
<td>Nearly zero</td>
</tr>
<tr>
<td>CHP Possible</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Commercial Status</td>
<td>Small Volume Production</td>
<td>Widely Available</td>
<td>Widely Available</td>
<td>Only Phosphoric Acid Fuels Cells Available</td>
</tr>
</tbody>
</table>

All dollar amounts in 2007 dollars. 
SOURCE: California Energy Commission; ESA.

Combustion turbine engines are a mature technology but scale issues for their implementation preclude their use with dairy digesters except for the relative large or centralized community systems. At the lowest end of the scale, at least 5,000 dairy cows would likely be necessary to generate sufficient biogas production. The conversion efficiencies for combustion turbines are also expected to be reduced at the scales likely to be applicable for any on-site or community systems.

Fuel cell technology is currently at an early stage of development and consequently the costs for fuel cells are many times greater than for comparably sized micro-turbine, turbine or IC engines. Even though the efficiency of fuel cells are considerably better than the other technologies, given this very large production cost differential, until major technological improvements and/or large scale commercialization is achieved, fuel cells will remain dramatically less cost-effective for implementation.

EPA estimates that that the maximum thermal conversion efficiency of biogas to electricity by a standard reciprocating engine (internal combustion) is 28.5%. However, due to the difficulty in sizing engine-generator sets for optimal efficiency as well as a likely on-line operating rate of 90%, electrical output for biogas is estimated to be 66.6kWh / 1,000 cu.ft. of methane. Other analysts recommend that realistically, the thermal efficiency conversion to electricity is between 18% and 25%.

Electrical production with biogas will remain an important potential alternative use for digester systems. Consequently, the electrical generation productivity will have a direct revenue effect by determine the amount of energy that can be sold or used from the system. But, as discussed below,

9 The reduced efficiency rates for biogas electrical generation compared to natural gas reflect the biogas’s lower methane and higher impurities content.
other factors such as pricing structures with local utilities will have a greater influence on the system’s overall economic feasibility than its electrical generation performance. However, it is possible that major technological advances could provide major improvement in the cost-effectiveness and/or environmental performance of future biogas electrical generation systems.

**Commodity Prices of Energy**

**Natural Gas**

Generally speaking, biomethane is a more valuable energy commodity to utilities than biogas generated electricity since the biomethane can be more readily stored for later use. Consequently, it is easier for utilities to use the biomethane as an energy resource during periods of higher energy demand (i.e., when its value as an energy resource will be higher).

In a fundamental way, the commodity price of natural gas constrains the economic value and sale price for digester system produced biogas and biomethane. Natural gas is a substitute energy alternative for on-site biogas use, off-site commercial sale or upgrading to biomethane. If the renewable and environmental attributes of the produced biomethane are considered separately (i.e., Renewable Energy Credits [RECs] and greenhouse gas [GHG] credits), then the core value of biomethane will be largely limited to the substitution cost for potential purchasers (e.g., such as industrial users or utility) to use natural gas to meet their energy needs.

In past years, the price of natural gas has fluctuated greatly. The price variability had been partly due to the major international oil price fluctuations and global economic instability. Current natural gas prices are approximately $5.40 /1,000 cu.ft.\(^9\) Extensive future supplies of domestic natural gas are currently believed to be available and ongoing technological improvements in natural gas recovery are expected to enable natural gas production to increase over the next 25 years. During that period, natural gas prices are expected to remain unchanged in real terms (USEIA, 2010).

While long term stable natural gas prices (in real terms) are good for the general economy, the absence of any significant future natural gas commodity price increase will undercut the future economic feasibility of biomethane production. If the sales prices for biomethane are restricted to current natural gas prices, any future production costs increases can be expected reduce the profitability of biogas production unless offsetting technological improvements are achieved.

Currently, biomethane pipeline injection is only permitted into PG&E’s transmission pipelines due to insufficient and inconsistent demand within its distribution network. Furthermore, to meet the utilities flow requirement, any biomethane injection to the transmission pipeline must occur near urban areas that have adequate and consistent natural gas demand.

An initial pilot project at the Vintage Dairy near Fresno is currently operating and processes manure from approximately 3,000 cows into biomethane. The dairy has successfully upgraded its biogas to meet PG&E’s gas quality requirements. Vintage Dairy is located along a natural gas transmission pipeline.

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\(^9\) City Gate Price for November 2009 (U.S.E.I.A, 2010).
line and therefore in able to inject on-site. In PG&E’s experience, biogas injection projects more than 4 to 5 miles from a transmission pipeline are less economically viable (PG&E, 2009). Other studies and analysts have also concluded that proximity to interconnection locations are a major limiting constraint for the feasibility of biomethane pipeline injection (Goodman, 2010). Consequently, the existing natural gas transmission system infrastructure is considered a key feasibility constraint for future development of any dairy biomethane pipeline injection within the Central Valley.

Biomethane could potentially be piped to local industry or commercial customers with sufficient energy needs. Again however, due to the relatively high cost of construction for delivery pipelines, proximity to the biomethane production facility will be a key feasibility constraint. Furthermore there are likely to be only a limited number of industrial or commercial users with adequate power demand.11

Alternatively, biomethane can be compressed or liquefied for truck transportation and/or transportation fuel use. The biogas conditioning requirements for compression biomethane (CBM) or liquefied (LBM) are comparable to those required for pipeline quality biomethane although specific users or fuel use may accept higher carbon dioxide levels.12 As is discussed in the assessment of production costs, the purified biomethane must not only be compressed or liquefied, but on-site storage is also likely to be necessary until it can be truck transported to its end customers. Given their very similar chemical composition, the market prices for compressed CBM and LBM are expected to be highly comparable to compressed natural gas (CNG) and liquefied natural gas (LNG) prices.13

The commercial sales potential for CNG and LNG are currently relatively limited. However, CNG offers substantial fuel cost savings as prices are currently averaging approximately $2.25 per gallon gasoline equivalent compared to diesel’s current $2.70 per gallon gasoline equivalent (cngprices.com 2010; CEC, 2010). The current market is primarily focused on sales as a “clean” transportation fuel for vehicle fleets. While municipal or government agencies have been major initial adopters of CNG vehicles, private companies are also considered potential customers. Presently, the main operational limits to CNG powered vehicles use is their horsepower constraints which make them less well suited for trucking us over major gradients. The greatest market demand for CNG fuel is within California’s major urban areas where the negative air quality effects of diesel trucks are highest and the CNG supply infrastructure can be most cost effectively developed.

Although, there are existing and future sales opportunities for CBM and LBM, it remains an emerging market that is constrained by the higher cost of conversion or purchase of CNG/LNG powered-vehicles and the need for expansion of the fueling infrastructure. Consequently, the value of both CNG and LNG are expected to remain closely related to natural gas prices with a relatively limited potential for any price “premium” for biomethane.

11 Under some circumstance and pending local air quality issues, it may be viable for “raw” biogas to be used for industrial or commercial heating systems. In which cases, if the relatively costly biogas upgrading are avoided, it could be economically viable to pipe the biogas further distances to commercial customers.
12 Acceptance of higher carbon dioxide proportion will offer some production cost savings.
13 If the biomethane’s environmental attributes (e.g., renewable energy credits [RECs]) are valued separately. Given the nascent CBG and LBG markets it should be conservatively assumed that no major premium biogas price would be obtainable – especially given the relatively small production levels likely for the foreseeable future.
Electricity

Similar to natural gas, electricity prices have a central influence in determining the economic performance of digester systems. The “retail” electricity price that farmers currently pay to meet their on-farm needs determines a maximum economic value for their potential electric cost savings earned by self generation. The avoided cost for purchasing electricity at the utility’s retail price will offer direct economic benefit for dairies that can self generate electricity on-site to meet their electricity needs. Electrical generation for on-farm use and/or net metering plays a vital role in the economic performance of current operating dairy manure systems (PERI, 2009).

Net Metering

Retail electric rates in California are comparatively higher than elsewhere in the United States and consequently will increase the potential economic attractiveness of alternative energy sources. Currently, the typical base “retail” electricity price facing farmers within the PG&E service area is $0.12 kWh to $0.14 kWh. However, during peak periods electricity prices can increase to more than $0.25 kWh (PG&E, 2010).

In 1995, the California State Legislature passed SB 656 (Alquist), which required all electric utilities to buy back any electricity generated by a customer-owned solar and wind systems system. This buy-back program is known as “net metering” because the electricity purchases of the customer are netted against the electricity generated by the customer’s renewable system. The customer’s utility bill is calculated on the net quantity of electricity bought from the utility. However, the utilities were not required to purchase any surplus generated by the customer and it was only the subsequent Assembly Bills 2228 (passed in 2002) and 728 (passed in 2005) that required the utilities to offer net metering to dairy farms that generated electricity with biogas.

Past net metering regulations did not encourage digesters operating as electricity “exporters” since the program only allowed them to “bank” their energy production in the utility grid. As a result, biogas producers often chose to flare excess biogas rather than generate electricity for which they would receive no compensation from their local utility. In addition, dairy farmers do not receive the full retail price for their self generated electricity but still incur tariff charges for transmission and distribution, demand charges, public purpose funds. These additional costs can be considerable – averaging $0.055 / Kwh (in 2005 dollars) for a typical dairy (Krich, 2005).

However, recent passage of AB 920 has amended the net metering provisions to require utilities after January 2011 to compensate customers for any surplus electrical production. This improves the future revenue potential for dairy’s self-generating electricity.

Feed-In Tariffs

Following the passage in 2006 of Assembly Bill (AB) 1969 (and subsequent CPUC rulings), PG&E and other California utilities14 are now required to buy excess energy generated with renewable sources from qualified customers. Dairies that generate electricity can choose to sell their surplus

14 Although several utilities serve farmers within the Central Valley, PG&E is predominant utility provide for the region and consequently the analysis primarily refers to PG&E in its discussion of utility issues.
electricity to their local utility under a Small Renewable Generator Power Purchase Agreement (PPA) provided they sell less than 1.5 MW of power (which at average of 0.107 kWhr / cow would be equivalent to surplus power production by 14,000 cows). This “feed-in tariff” program is in some ways a more sophisticated net metering program as the dairy’s usage and exports to the grid are both measured for quantity and by time of delivery. Under the feed-in tariff program, small renewable energy producers are able to obtain long-term contract for their energy production at a very low transaction cost which should assist in raising capital investment. This is a primary benefit offered by the feed-in tariff program to potential dairy digester developers.

Under the feed-in tariff program the purchase price for excess power is set by the CPUC according to the market price referent (MPR) determined as part of the State’s renewable portfolio standard proceedings. The MPR values offered under the feed-in tariff program are based on the comparable costs for electrical production at large scale utility power plants. As such, the MPR is unrelated to the actual cost of renewable energy production and therefore does not provide any subsidy to encourage specific renewal resources.15

The prices paid for the surplus power is also adjusted for its “time of delivery” which recognizes the higher value of power supplied during on-peak periods and its lower value during off-peak hours. Current MPR values are approximately $0.09/kWh and producers can enter into 10, 15 or 20 year contracts with the utility (PG&E, 2010).

The feed-in tariff programs provide an improved mechanism for dairy digester to sell surplus electricity. However, the set price for the MPR price and low off-peak rates can nonetheless result in average electricity prices that may be insufficient to fully compensate for the electrical generation system costs. Furthermore, the long term contracting terms lack escalation provisions and this can be a disincentive for electrical producers deciding between participating in the feed-in tariff or net-metering programs. However, it may also be possible with suitable gas storage and design that a digester system could be operated beneficially as a peak power operation under the feed-in tariff program so that the dairy sells most during peak or partial peak periods (PERI, 2008).

While the feed-in tariff program improves the revenue potential for on-site electrical production, it does not maximize the economic benefits to the dairy. Under the current feed-in tariff programs, Californian utilities are prohibited by regulation from “wheeling” electricity from the dairy – even amongst the dairy’s own electrical accounts. For example, a dairy farm with several electrical accounts (e.g., for refrigeration, irrigation systems, lighting and home use) will have to sell the power in excess of that it consumes on its producing electrical line (i.e., that connected to the generator system). Under the PPA agreement terms with the utility, the dairy would earn revenues (which may be near to a wholesale price) while at the same time being charged at a higher retail price for the electricity it is consuming on its other electrical accounts. Under this arrangement,

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15 Some industry experts suggest that the MPR is too low to provide sufficient financial support for the development of new renewable energy projects. Consequently, the CPUC is currently also considering the implementation of “reverse auction” as future funding. If approved, potential renewable energy producers could bid the rates at which they would supply electricity. The major utilities would then select the lowest cost bids from qualified producers. Such an approach could enable the producers to contract for renewable energy at higher than MPR rates.
the dairy loses some of its potential avoided cost savings that it could earn if it was able to fully serve its own electrical needs from its own electrical production.

The feed-in tariff program is available on a first-come, first served basis and PG&E’s obligation for the program serving manure digesters and other non-water/wastewater customers will end when 104.6 MW of installed renewable generation will operate under the program. As of February 2010, only the Castelanelli Bros Dairy has enrolled in the program (PG&E, 2010).

The most recent analysis by the CEC predicts that California’s system-wide average retail electricity price will not increase in real terms between 2010 and 2016 (CEC, 2007). If electricity prices remain stable, then there will be reduced economic incentives for on-site electric generation use of dairy digester biogas.

In summary, electricity prices are a direct and fundamental driver of dairy digester feasibility. The revenue boundaries for digesters systems are determined by both the retail prices paid by electrical consumers and the wholesale prices and contract terms by which utilities will purchase any on-site surplus electrical production using biogas / biomethane. The terms of any feed-in tariffs, PPA and other price factors (e.g., time of delivery pricing) will determine and incentivize the dairies’ production levels and use/sale of their biogas. Currently, much of these terms are set by the CPUC regulations and policy which determine not only the MPR but also authorize the utilities’ prices to its consumers and their ability to “pass on” any electrical purchase costs. Similar to other distributed generation and renewable resources, these financial factors may be expected to have an important, albeit complicated role, influencing the economic feasibility for manure digesters in the Central Valley.

Byproduct Values

Digestate Use Values

Most feasibility studies of dairy digester systems estimate an economic value for use of the digestate by-products. Depending on its water content, the digestate can be spray applied to crops as a fertilizer supplement / replacement, used as compost material or livestock bedding material.

The quantity and form of the digestate will be related to the anaerobic process used. Lagoon digesters will result in predominately liquid digestate while the complete mix digesters typically produces a denser slurry digestate. The plug-flow process results in a wet solid digestate material. The digestate can be heated or otherwise dewatered to separate the solid fraction for use as a compost material or bedding. If a dairy farmer has insufficient land to accept all its digestate, the material can generally be transported short distances to other nearby farm operations. In many cases, the digester owner will earn a small payment for the effluent (Martin, P., 2010).

The extent that the digestate by-product can be used as a soil supplement or fertilizer replacement will depend on the farmland soil conditions and crop types as concerns about salt and nitrate loading limit its land application rates within the Central Valley. Currently, single crop farming in the region can typically accept approximately 2,000 lbs of manure or digestate per acre annually while double cropped fields can receive 3,000 lbs per year. Given that a cow will produce approximately one
ton (2,000 lbs) of manure solid a year, the quantity of digestate that will remain after anaerobic
digestion will be approximately 60% or 1,200 lbs per cow per year (Clear Horizons, 2006).16

Some analysts argue that most digestate uses should not be recognized as an additional revenue
source for the digester since the dairy’s manure would otherwise be similarly reused on-site. In
which case it may be argued that no new net revenue has been generated unless manure or other
feedstocks (if co-digestion is occurring) has been imported (Hall, 2010).

In any case, the potential value of avoided bedding costs will be very minor. Although bedding
sales of digestate are commonly estimated to be approximately $20 - 25 per ton (Clear Horizons,
2006), according to USDA statistics, less than 0.28 percent of the total dairy budget was spent on
bedding and litter materials for the average California dairy operation (USDA, 2005). Consequently
the avoided cost of digestate use for bedding or revenues from their sales can be expected to have
a minimal if not negligible effect on the economic feasibility of any manure digester systems.

The compost value of digestate is considered to be potentially significantly higher if it can be sold
commercially.17 Green waste recyclers report sales of up to $18 per cubic yard ($90 per ton)
(SAIC, 2002). However, wholesale values of the digestate may be far lower. In an analysis of a
large centralized digester system Hurley estimates that the net value of the digestate would be $5 /
ton which was consist with several other studies (Hurley, 2007).

Again, given the relatively minor net value of the bulky digestate and recognition that it is arguable
that any net material gain has occurred (and in actuality likely to have been a 40% loss in biomaterial
material weight in the manure to digestate conversion), the value of the solid digestate as a compost
revenue may be expected to have a minimal contributory effect to the digester feasibility.

**Effluent Use**

Digester effluent is typically applied to dairy farmers’ fields for feed crop production. As discussed
above for the solid digestate, it is arguable whether any revenues or avoided costs associated with
the use of the effluent by-product will represent a net revenue contribution. Unless organic feedstock
material has been imported (which would increase the effluent quantity and/or fertilizer value),
then the farmer’s fertilizer expenditure would be expected to relatively unchanged. Consequently,
only co-digesters or centralized manure digester systems would be expected to generate net revenues
from digester effluent use that would represent additional revenues potentially improving the project’s
feasibility. Furthermore, if the location of the digester has insufficient onsite capacity to accept
on-field applications of all the generated effluent (or solid digestate), then disposal of the effluent
could add costs that would further decrease the project’s economic feasibility.

The potential applied fertilizer cost savings with effluent use will have greater potential economic
than solid digestate uses. Furthermore, unlike the quantity of manure solids which is substantially

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16 Assuming substrate volatile solid content of approximately 65% (i.e., manure with bedding) of which 60% would
be converted to methane.

17 Technically, the digestate is not actually compost material since it has not been aerobically decomposed, however it
has very similar uses and nutrient value for soil application as compost.
reduced by the anaerobic digestion process, most of the nitrate, phosphorus and, to a lesser extent, potassium content will remain in the effluent and digestate. As a result, any use of imported feedstock will likely add additional nutrients. While such nitrogen and other salt accumulation can present potential water quality concerns if improperly managed, the high costs of fertilizer ensure that effluent can have reuse value to the dairy and other nearby farms. Farm studies indicate that the fertilizer value of untreated manure can be significant – conservative estimates from a 1997 study estimate the annual value of untreated manure to be over $100 / cow (in 1997 dollars) (Hart, 1997). However, these fertilizer cost saving are also more applicable to higher value commercial crops rather than feed crops. Nonetheless, it can be reasonably expected that on a per cow basis, new net effluent gains would have some positive revenue value for the dairy.

It has been suggested by some industry analysts that large scale effluent treatment to separate out the nitrogen, phosphorous and other salts could generate highly valuable organic fertilizer byproducts that would be suitable for use by drip feed irrigation systems. Such an additional effluent processing component to the dairy digester facility would be costly with developer costs and economies of scale similar to those necessary for biogas upgrading systems. However, given the high costs for fertilizer purchases, the high concentrate organic byproduct would have significant value which according to some experts could be a major economic driver for the digester system (Best, 2010). Furthermore, such a digester effluent treatment system would sequester nitrogen and salt thereby improving the dairy’s water quality management practices.

In general, net effluent gains for co-digesters or community digester systems may represent a positive albeit relatively minor supplemental economic factor for system feasibility (subject to local farmland soil conditions).

**Tipping Fees (Co-digesters only)**

Most co-digester studies argue that that tipping fees for the feedstocks processed by co-digesters are important revenue sources. Several studies have concluded that tipping fees can be crucial factors is determining the viability of the digester project (Moffatt, 2007).

However, it is essential that the net revenues for sourcing co-digester feedstocks are understood so that the net revenues to the digester project can be correctly determined. “Tipping fees” generally refer to the price paid for disposal of the organic wastes. In some cases, the waste producer may also incur additional transportation costs for removal of the waste. Co-digester operators sourcing feedstocks for their facilities will similarly need to recognize the costs for transportation (and possibility storage) of the feedstock to determine the cost-effectiveness of feedstock additions for their biogas production.

In most cases, waste-to-energy facilities are able to obtain a disposal or tipping fee for feedstocks that increase biogas production and add revenues that assist in offsetting facility construction and operating cost expenses. Such disposal fees currently range from about $50 to $60 / ton in California.

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18 It should be noted though that the site-specific soil and groundwater conditions may reduce the effluent’s value if the land application rates of local farmland are too restrictive.

19 Not including the development of major effluent processing component.
However, most of the feedstocks are potential commodities for which supply, demand and prices are susceptible to change. Relatedly, most commercial feedstocks (e.g., agricultural or food processor wastes) are expected to be available only seasonally and on a short-term contract basis. Digester operators will likely have to obtain a variety of different feedstock materials from numerous sources. Municipal green waste is currently identified as one of the more reliable potential feedstocks. As competition increases for these resources this trend may reverse and tipping fees may decrease. Costs for collection, transporting and storing agricultural residues uses are typically in the range of $25 to $50 per dry ton. Transportation costs of $0.20 to $0.60 per mile per ton are typical for feedstock delivery (Jenkins, 2006). Other analyses have identified loading and unloading costs of $0.40 / ton (2007 dollars) with a $0.18 / ton / mile transportation cost (Moffatt, 2007).

Tipping fees can offer additional revenues for co-digester systems but transportation and storage costs may reduce the net revenues for the digester operator. Given the uncertainties and geographic considerations associated with current and future feedstock commodity values, it is conservatively considered that tipping fees should be recognized as at most a minor secondary supplemental revenue source solely for co-digester systems.

**Greenhouse Gas Emission Reduction Credits**

There are two types of potential greenhouse gas (GHG) credits that may be derived from digester systems: (1) Credits for methane destruction (carbon offsets); and (2) Credits for Fossil Fuel Displacement (renewable energy credits).

Methane has 23 times the greenhouse gas impact of an equivalent weight of carbon dioxide (CO₂). Consequently, each ton of methane that is intentionally destroyed will have an equivalent GHG reduction value of approximately 23 tons of carbon dioxide. Use of renewable fuels for power generation also has a secondary benefit that carbon currently stored in fossil deposits is not added to the environment. Renewable Energy Credits (RECs) in effect account for the fossil fuel displacement effects and are discussed separately below.

A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” (i.e., the offset provider must prove that the project would not have happened without its financial investment and that the project goes beyond “business as usual” activity).

The methane collection and use associated with anaerobic digesters systems can result in considerable reductions in GHG releases. Flaring of collected biogas will result in a net GHG impact reduction as the more volatile methane is converted to carbon dioxide which has less than a twentieth of the climate change effect. Productive use of anaerobic digester biogas will result in additional GHG benefits as the biogas generated energy will reduce the corresponding utility generated GHG emissions that would otherwise be necessary.
Currently, there is an emerging international and domestic market for greenhouse gas emission offset credits (often referred to as carbon credits). Both the European Union (EU) and Chicago Stock Market (amongst others) operate “carbon markets” for the purchase and sale of certified carbon credits. In addition, potential GHG credits have to be certified to verify their effectiveness. Numerous organizations operate GHG verification programs both within the U.S. and internationally (e.g., the Voluntary Carbon Standard Association and Gold Standard Foundation). Within California, the California Climate Action Registry (CCAR) has approved protocols to quantify and certify GHG emission reductions which are applicable to manure digesters.

Presently participation in GHG markets is voluntary within the United States. Nonetheless, many businesses are currently purchasing carbon offsets to support projects that reduce GHG levels. Consequently sales of carbon offsets may be an additional revenue source for future digester projects. However carbon offset prices are subject to market conditions and price volatility. Between 2005 and 2007, carbon reduction credit values were as high as $50 per ton of CO\textsubscript{2} equivalent. More recently, carbon values have been considerably lower - typically in the range of $10 per ton. Since the market is based on both the supply and demand for carbon credits, it is difficult to project the future carbon credit values.

PG&E currently operates its Climate Smart program which allows participating customers to elect to pay an additional monthly premium to fund CPUC-approved projects that reduce GHG emissions. Climate Smart acquires 1.5 million tons of carbon credits annually and as such is the largest single carbon credit purchaser in California. Residential, businesses and municipal customers participating in the Climate Smart program are purchasing GHG offset credits which fund renewable energy purchases and development. PG&E estimates a current carbon reduction price of approximately $7 per metric ton of CO\textsubscript{2} for its Climate Smart program. Given an annual GHG impact equivalent to 4.6 tons of carbon per year, the current potential carbon offset value for qualified dairy digesters would be approximately $32 per cow (Brennan, 2009).

A central issue for carbon credits is “additionality.” Additionality considers whether the GHG reduction is discretionary and whether the carbon offset purchase actually ensures carbon reductions, or whether the reductions would have occurred regardless. If the carbon offset purchase is a key factor in making the reductions happen, the reductions can be considered to be “additional” to the business-as-usual case. If anaerobic digesters become the Best Available Control Technology (BACT) for dairies’ waste management, then digester collection of methane would no longer represent “additional” carbon reductions and so would no longer qualify as carbon credits. Under such circumstance, existing GHG credits would remain valid until the end of their ten year term but new credits would not be authorized (CCAR, 2007).

**Renewable Energy Credits**

Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.
Renewable Energy Credits (RECs), as statutorily defined, are not created until electricity is generated. Therefore biogas digesters, unlike wind turbines and geothermal facilities, in and of themselves have no RECs to convey. However, if the digester biogas end use will replace the use of fossil fuels for energy production then the digester can qualify for fossil fuel displacement credits. As a renewable resource that can directly substitute for natural gas use, biomethane or biogas used for electrical generation or injection into the utility grid will qualify for REC credits.

The value of the fossil fuel credits also depends on the fossil fuel use that would be displaced. Consequently, California fossil fuel displacement credit values for electrical generation use are lower than elsewhere within the most of the United States due to the fact that no coal fired power plants operate within the state. Under the State of California’s Renewable Portfolio Standards (RPS) requirements, there is an emerging market for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters. The generation of renewable energy from the dairy digester systems can be quantified and certified for sale as a renewable energy credits.

A digester system developer retains the RECs for self-generated power used on site while the utility receives the remaining REC credits for any surplus electricity it has purchased. Utilities and other entities that need these “green tags” to comply with California’s Renewable Portfolio Standard would be potential purchasers of digester RECs. In addition, other businesses wishing to support renewable energy might also be interested in purchasing digester power RECs. REC prices are subject to market conditions but could be expected to be $0.002 to $0.005/kWh (CH2M Hill, 2006).

Currently, most RECs within California are sold bundled with the associated renewable energy. Consequently, utilities such as PG&E that are negotiating long term renewable energy purchases acquire the REC values with the resource’s material value as a fuel. Consequently, the sale price for the renewal resource has a price premium component for the included REC. However, the REC values for self-generated energy used by the dairy will be retained and would be potentially available for sale and purchased.

There are no established REC values for biomethane use as a transportation fuel. However, future implementation of the California Low Carbon Fuel Standard (LCFS) is expect by many industry experts to encourage the future of REC values applicable for future use of biomethane (either as CBM or LBM) as a replacement for diesel and gas fuel (Price, 2010). Although very difficult to value at this point in time, some industry experts maintain that the future REC values for biofuels could add additional revenues for digesters systems producing CBM or LMB.

**Other Economic Benefits of Sustainable Farm Production**

Currently, several of the farms with operating digester systems receive significant attention for their pioneering sustainability improvements and use of biogas as a renewable energy source. Hilarides Dairies use of cow power for its trucks and Fiscalini Farm’s use of its biogas for its

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20 Consequently, biomethane production for use as transportation fuel will not qualify for RECs.
21 The sale and purchase of tradeable REC’s for utility compliance with RPS is currently under agency review and consideration by the CPUC.
cheese production are two notable examples. Similarly, the Straus Family and Gallo Farms also differentiate their dairy operations by their implementation of more sustainable farming practices.

However, as yet there is no appreciable market or economic value to these and other California dairies rewarding them for adopting more sustainable business practices. While “greener” businesses in other sectors may be able to leverage their sustainability commitments for an improved market position or marketing benefit, there is currently little potential for dairy farms to capture any such similar benefits. Due to California’s regulated milk sales market and relatively few dairy producers that sell directly to retailers, most dairy farmers are “price-takers” (LaMendola, 2010). Dairies such as Straus Family Farms that have a brand identity and sell their dairy goods to consumers are very few in number and represent a very small portion and niche of the dairy market. Premium prices for “greener” dairy producers are unlikely to be achievable in the foreseeable future particularly during a depressed economy and relatively low public awareness of the potential for more sustainable production practices such as dairy digesters. Furthermore, due to the largely consolidated market for most dairy goods and the perishable nature of milk itself, emergence of any sales premium or selection preference for dairy products from “sustainable” dairy farmers will likely require a considerable increase in prevalence and/or accreditation labeling (i.e., a “green” stamp of approval) before wholesalers and/or other large customers can and will begin to select amongst dairy producers for those more sustainable producers.

As a result, it is considered unlikely that dairy farmers will be able to gain any significant economic premium for their dairy products from their digester operations.

Government Grants and Assistance

Currently most operating digester systems receive considerable government funding assistance. Anaerobic digester projects qualify for many of the federal and state programs promoting renewable resource development. Governmental assistance and support can be provided in the form of grant funding, low-interest loans, tax incentives and/or technical support. The main forms of government support currently available for biomethane production by dairy manure digesters are identified below. Individual digester projects will have to qualify for assistance on a case by case basis and projects will typically receive assistance from only a few programs.

Renewable Energy Production Tax Credit. Under this federal program authorized by the 2005 Energy Policy Act, qualifying renewable energy producers can obtain $0.015/kWh in production incentives. The program is currently authorized to continue until 2026.

USDA – Renewal Energy Program. The program provides grants and loan guarantees to rural small businesses and agricultural producers for up to 25% of the cost to purchase and install renewable energy generation systems up to $500,000.

Self-Generation Incentive Program for Renewable Fuel Cells. Authorized by the CPUC, this utility administered program provides financial incentives for installation of new, self-

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22 The Feed-in Tariff program authorized by the CPUC is discussed previously under the electricity price section.
generation equipment installed to meet all or a portion of the user’s electric energy needs. The program was originally designed to complement the CEC’s Emerging Renewables Program (ERP) by providing incentive funding to larger renewable and non-renewable self-generation units up to the first 1 MW in capacity and subsequently increased for units up to 3 MW in capacity. Renewable fuel cell systems can receive a $4.50 /watt as a one time capital payment (but not to exceed 50% of the total cost). Non-renewable fuel cell systems can similarly receive a $2.50 /watt capital payment.

California Energy Commission - Renewable Energy Program. The Existing Renewable Facilities Program provides production incentives, based on kilowatt-hours generated, to support existing renewable energy facilities. In addition, the Emerging Renewables Program provides rebate funding for solar and fuel cells that use renewable fuels (such as biogas). The program has $65.5 million in funding until 2011.

State Assistance Fund for Enterprise, Business and Industrial Development Corporation: Energy Efficiency Improvements Loan Fund. This long standing state program offers low interest loans to small businesses in California for renewable energy systems. The maximum loan amount is $350,000 at 4% interest with a five year repayment period.

In addition to these current programs, the State of California (administered by the CEC) provided significant funding assistance to manure digester and other similar renewable resource projects through both its former Dairy Power Production Program and research conducted under its Public Interest Energy Research Program (PIER). As discussed previously in the Renewable Energy Credits discussion, the State of California Renewable Portfolio Standards (RPS) requirements also provides indirect support for manure digesters by fostering an emerging market within California for the sale and purchase of renewable energy credits from renewable resource producers such as dairy digesters.

Recent economic analysis of dairy digester systems installed under the California Dairy Power Production Program determined that without government subsides, even the best constructed / operated digesters would have electrical production costs that are “high tending to be above market rates” (PERI, 2008). Even factoring in government subsides, the cost of energy for other digester systems were such that while several digesters were marginally profitable, several others operated at a negative rate of return.

Together these past and current programs illustrate the important role that state and federal programs contribute to fostering the development of manure digester systems. The financial and technical support is widely agreed to be an important and positive influence improving the feasibility of manure digester development. Furthermore, given the increasingly complex regulatory conditions facing dairy farms and renewable energy projects, as well as the financial challenges remaining before full commercialization of the manure biogas/biomethane production is expected to occur, continued governmental support is expected to remain an important and essential economic driver for future manure digester development for the feasible future.
Cost Factors

These costs typically will consist of both:

- Initial construction and equipment costs for development of the digester project. In many cases there may be significant economies of scale as the system capacity increases. The construction and/or equipment cost will also likely vary depending on the technology adopted.

- Operating and maintenance cost for the project. This will include the labor and input costs including required energy. Typically, these are variable costs and will vary with the level of production. The operating and maintenance cost may also vary depending on the technology adopted.

The following section identifies the major cost factors that influence the economic feasibility of biogas production by dairy manure digester systems. These factors are naturally inter-related with the revenue factors discussed above. Just as market conditions will determine the revenue potential for digester biogas and its other byproducts, technological and equipment supplier conditions will be key cost determinants on economic viability. Consequently, major technological improvements that greatly decrease unit production costs will enhance the economic feasibility of dairy digester development. Conversely, additional equipment / processing requirements (i.e., as result of new regulatory compliance requirements) that increase unit production costs will reduce the dairy digester system’s economic viability.

As will be discussed below, economies of scale can have an important role determining unit production costs and consequently the economic feasibility of the system. In some cases, scale issues will be limiting factors. Major equipment components may require minimum quantities of process throughput to operate adequately and in such cases these technological/operational constraints may dictate system design parameters.

Finally, it is worth noting that costs are generally easier to estimate than revenues which typically face more future variables. This is particularly apparent when the digester system’s operating assumptions and conditions are defined. Review of past digester studies offer far greater cost information than is provided for their revenue projections. In any case, care should be taken to ensure that estimated costs are properly matched with operational / output assumptions. It should also be recognized that site specific conditions can both positively or negatively affect the actual system development costs considerably.

Manure Collection / Preparation as Feedstock

The dairy manure collection costs for on-farm digesters are considered to be negligible since similar manure management practices are already a necessary component of existing dairy operations. Furthermore, the transportation distance within the farm will be very limited. In addition, relatively little pre-digester preparation is expected to be necessary for the manure. Any grinding or filtration necessary will be very minor in cost compared to the digester itself.
For a centralized or community digester system, manure transportation costs may be a limiting factor that could offset economies of scale that might be gained from larger anaerobic digester facilities. Manure from the individual farms could either be piped to the centralized digester through a sewer system or possibly be transported by trucks. Analysis by Ghafoori and Krich suggest that development of a piping system for dairy manure is prohibitively high from a construction cost basis (Ghafoori, 2005; Krich, 2005). Furthermore, such systems would incur major additional investment cost and could face significant additional difficulties with site and easement requirements.

**Anaerobic Digester Systems**

As discussed previously, anaerobic digester systems are relatively simple and well established technologies. Although there is potential for future productivity improvements, construction specifications and costs are relatively well defined. Most of the system components are relatively standard and readily available. Other construction costs (e.g., such as siting and land preparation) will be relatively straightforward.

The selection of specific anaerobic digester technologies will be primarily determined by the dairy’s manure management systems. While site specific requirements may necessitate some tailoring of digester configurations, construction costs should be relatively comparable between dairies located within the region. As a relatively simple and mature technology, future equipment and development costs for anaerobic digester systems are not expected to change substantially. Future technological improvements are expected to be predominantly incremental. Therefore, while digester system construction costs will represent a secondary factor in determining the economic feasibility of manure digester systems, this cost factor is expected to remain relatively constant and therefore represents a minor economic driver.

Operating and maintenance costs for digester systems remain largely under-analyzed. If feasibility studies consider the system operating and maintenance costs at all, most typically attributed a percentage cost of the project’s construction cost. While improved remote sensing and automated control systems can assist digester management tasks, many industry analysts agree that most studies do not fully recognize the labor likely involved to operate digester systems (Summers, 2010).

In any case, given the comparative simplicity and mature technology used for manure digester systems, operating and maintenance costs may be expected to make a very minor contribution to the digester overall economic feasibility. Furthermore, no significant cost improvements can be expected to the anaerobic digester process that would substantially improve overall system feasibility.

**On-site Heat/Boiler System**

On-site heat generation from biogas is predominantly used for heated complete mix or plug flow anaerobic digester systems. Otherwise, unless major milk processing is occurring on-site, most dairy’s heating demand will be relatively limited and can be met with standard boiler systems that can be fairly easily modified for use with biogas (although air quality compliance may be problematic). The capital cost for conversion or purchase of suitable heating systems will be relative minor. In most cases, heat generation will be limited and only a secondary use for dairies of any produced...
biogas. Therefore, heating use of biogas will have a very minor influence on the digester’s economic feasibility. Furthermore, no major technological improvement or future significant cost savings can be expected related to biogas heating systems that would improve overall system feasibility.

If on-site electrical generation with biogas is planned, combined heat and power (CHP) designs typically can offer cost effective opportunities to use thermal energy that would otherwise be lost. However, given most farm’s limited heating needs it likely that surplus heat would still be generated. Consequently, while their may be opportunities for cost effective efficiency gains, the magnitude of the economic benefits will remain minor and will not be expected to be a significant economic driver of system feasibility.

**On-site Electrical Generation**

As discussed above, on-site electrical generation has generally been the primary use of biogas produced by on farm digester systems. Except for the Vintage Dairies facility which is producing biomethane for pipeline injection, all the other manure digester systems operating in California are using their biogas production to produce electricity on site. Electrical generation with internal combustion (IC) engines is a very well established technology that can be applied at both the full range of production scales and under a wide variety of operating conditions. Generally speaking, outside California, electrical production with internal combustion engines can be cost effectively performed to meet not only all on-farm needs but also to generate surplus electrical energy which can be exported to other users or to the grid under net-metering or distributed power arrangements with local electrical utilities.

The national average on-site electrical usage for dairies is 550 kW / cow / year (Barker, 2001). At a typical retail energy cost of $0.12 kWh, the annual electrical cost for each dairy cow would be $66. If it is conservatively projected that each dairy cow can generate 0.1 kW/hr, then an annual basis total value of the potential electrical production would be 876 kW/cow/year which would be worth approximately $105 per year per cow of which approximately $39 per year would be the potential value of the surplus electricity at average retail electricity prices.

Yearly operation and maintenance costs for electrical generation systems are typically estimated to be in the range of $0.015/kWh (Jewell et al., 1997; Hurley, 2007) which reduces the system operator net revenues/saving.

However, as discussed in more detail below, future electrical generation with biogas at dairies within the Central Valley is highly problematic due to recent air quality regulations that prohibit IC engine use unless NOx emissions can be reduced to 9 – 11 ppm or less. It is currently unclear whether the use of on-site electrical generation equipment can be cost-effectively applied in the near term for dairy digester systems in the Central Valley.

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23 Hilarides Dairy also produces compressed biomethane with some of its digester biogas for use as a biofuel by its specially converted trucks.

24 Although as discussed under the Electricity price section, under the net metering program additional tariff costs for transmission and distribution, as well as demand charges may also be incurred. In addition, the interconnection process prescribed by CPUC Rule 21 can also require additional costs to the dairy.
On-site generation of electrical power is an important potential use option for dairy digester biogas/biomethane. As a form of distributed power, such on-site systems offer possible direct economic benefits and reduced overall environment impacts. However, given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically infeasible in the Central Valley until major improvements in the technical capabilities and costs for new microturbines or fuel cells are achieved.

**Biogas Upgrading**

The fundamental purpose of biogas upgrading is to increase the proportion of methane from its 50 to 65% concentration to near pure methane (95-99%) while removing the corrosive H$_2$S and CO$_2$ impurities.

The specific gas quality standards for biomethane to be accepted into the PG&E natural gas system are set in PG&E Gas Rule 21.C and by Rule 30 requirements for SoCalGas. Key utility specifications include less than 1% CO$_2$ and 4 ppm of H$_2$S content.

The upgrading requirements for biomethane production to pipeline injection standards are comparable (and typically higher) than those required for CBM or LBM production. Therefore the primary economic differentiators between biomethane uses (e.g., pipeline injection, compressed biomethane or liquefied biomethane) will be associated with subsequent delivery and market requirements for the different uses.

There are three main processes necessary for refining biogas into biomethane. The technologies for each of the procedures are well established and widely used but generally are implemented at a scale far larger than the production levels that even large dairy digesters would be able to attain based on its own herd size.

**Scrubbing (H$_2$S removal)**

Hydrogen sulfide (H$_2$S) is a highly corrosive impurity within biogas as it readily combines with water to form sulfuric acid. Generally, H$_2$S concentrations in raw biogas are typically 0.5% or less and can be problematic for many gas uses. However, for “lower tech” applications (such as boiler systems or internal combustion engines) regular and increased maintenance can be used to cost effectively manage most of the potential corrosion effects. Of the numerous potential scrubbing processes, iron sponge scrubbing is generally considered the most suitable for on-farm H$_2$S removal (Krich, 2005).

**Conditioning**

Water removal from biogas is a relatively straight forward and can be achieved through refrigeration of the biogas to condense out the water content. Using a relatively inexpensive commercial refrigeration unit and minor parasitic energy loss (2%) the water content in the biogas can be adequately reduced to acceptable levels.
Carbon dioxide is the most critical and expensive impurity to remove from biogas. Due to its relatively inert chemical composition and high concentration levels within the digester biogas, more extensive gas treatment is necessary for carbon dioxide removal. Water scrubbing is a relatively simple and low cost conditioning that is considered suitable for on-site dairy use. Although less efficient than other “higher tech” approaches, water scrubbing is most environmentally benign. Alternatively pressure swing adsorption (PSA), amine scrubbing and other technologies are available which offer some advantages for some applications (e.g., compatibility with LBM) but also present cost or environment byproduct disadvantages.

Biogas upgrading is likely necessary for any off-site use of digester biogas. The processing equipment, and to a lesser extent, the operating and maintenance costs, required for biomethane production will add considerable cost to the digester system. As a result, the unit cost for the biomethane will be increased substantially. While increasing the size of production levels can help to lower the unit cost of production, the volume of production necessary for most applications of the scrubbing and conditioning equipment remain relatively high due to the fixed cost of the technology. Furthermore, diseconomies of scale may begin to be incurred if the digesters can not be favorably located and clustered. Several previous feasibility studies have suggested that biogas upgrading systems would need to process the biogas of 10,000 cows although other suggest that full production cost efficiencies for pipeline injection would require 30,000 cows (Goodman, 2010).

As a result, unless future technology improvements can cost-effectively scale down biogas upgrading systems, it is likely that current biogas upgrading technology requirements will remain a major factor restricting economic feasibility.

**Distribution / Transmission System**

The construction costs for biomethane pipelines can vary considerably. Typically pipeline costs are estimated to range from $100,000 to $250,000 per mile. While the operating cost for pipeline delivery will generally be very low, the initial construction will represent a significant additional investment cost – especially compared to tanker truck delivery. Given the comparatively high cost for pipeline delivery, it has generally been judged that pipeline delivery of biomethane for any significant distance will not be economically feasible. Some analysts suggest that at most one or two miles in most cases would be a limiting distance for pipeline use (Krich, 2005). Others maintain that up to five miles may be viable under certain conditions (Brennan, 2010).25

Pipeline distribution costs also will play a fundamental role determining the feasibility of a centralized biogas treatment facility serving several dairy digester systems. Cost effective development of a centralized biogas treatment facility will require the farms’ digester systems to be clustered close together. Furthermore, the combined biogas production must be sufficient to ensure an adequate supply to attain the necessary economies of scale for cost-effective biogas upgrading. Otherwise, the pipeline transmission costs to import the additional biogas from more distant producers may place additional cost burdens that undermine the collective enterprise’s overall feasibility.

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25 PVC like pipe materials are also available for raw biogas transmission. However, as an even lower-grade and less valuable fuel it is will be less economically feasible to transport than the refined biomethane.
One advantage of pipeline injection for biomethane is that only limited on-site gas storage facilities will be necessary. CBM and LBM production will require both storage and truck transfer facilities. Standard and relatively inexpensive propane tanks can be used for low pressure biomethane storage (i.e., up to 300 p.s.i.). This is most suitable as intermediate storage of the biomethane output from the upgrading facility. Biomethane must be further compressed to 3,000 to 3,600 p.s.i. (i.e., equivalent to CNG pressure) for delivery and use as a transportation fuel. LBM has to be liquefied at pressures of over 5,000 p.s.i and maintained at low temperatures. Such high pressure storage is expensive and relatively complex to maintain.

**Pipeline Injection**

Currently, although California utilities are willing and able to purchase biomethane produced by manure digesters, the supplying dairy must provide all the facilities necessary to deliver pipeline quality biomethane to the utility’s natural gas transmission system. Furthermore, the dairy (or third-party developer) must also perform the scrubbing and compression of the biomethane as well as install and operate the metering equipment and pipeline tap (Brennan, 2010). In addition, proximity to the natural gas transmission line will also be a major limiting factor. As discussed earlier, pipeline delivery costs will likely ensure that any biogas/biomethane production facilities for pipeline injection will have to be located at most a few miles from suitable connection locations to the transmission line.

Biomethane producers injecting biomethane into the existing natural gas transmission pipeline will incur an interconnection cost. Interconnection costs to the biomethane producer will vary depending on the utilities being served. Recent estimates for the connection cost for biomethane injection into PG&E transmission system are $0.265 million for biomethane producers injecting less than 500,000 cu.ft. per day. SoCalGas will charge biomethane producers the same rates as those for a tradition natural gas interconnection. Projects injecting up to 1 MM cu.ft. / day will pay approximately $0.8 million to access the SoCalGas transmission system (Anders, 2007). The connection costs for pipeline injection are considerable and will require a greater scale of production so that the added costs can be adequately distributed to result in a manageable unit cost basis. In any case, the utility connection costs will represent a significant factor reducing the potential economic feasibility of biomethane production from dairy digesters. Furthermore, pipeline injection use of digester biomethane will be geographically constrained due to the high cost for any pipeline or vehicle transport of the biomethane between the digester and suitable injection points which must be along the natural gas transmission system.

**Compression / Liquefaction**

Methane requires 5,000 psi for liquefaction and it requires major applied energy to attain. Compression of biomethane only to 1,000 psi requires approximately 207 Btu of energy to compress each 1,000 Btu – a considerable parasitic energy “loss” or cost of 20.8 percent (Hansen, 1998). This does not include efficiency losses associated with the compression engines themselves.

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26 PG&E will provide the pipeline tap and metering equipment for large suppliers (i.e. those delivering 500 M cu.ft. or more per day).
There are major scale constraints for liquefaction and distribution of biomethane. Due to the cryogenic nature of liquid biomethane, significant energy must be used to maintain the produced LBM at very low temperatures to avoid the liquid “boiling off.” The potential energy losses for storage of LBM can be significant. Therefore, industry analysts suggest that liquefaction facilities should at a minimum be sized to produce adequate LBM to fill a standard tanker truck (approximately 10,000 gallons) every three or four days to reduce on-site storage losses.

**Biomethane for Fuel Use and Conversion Costs**

In recent years, the State of California has conducted extensive analyses and taken several actions intended to encourage the development of alternative vehicle fuels including Executive Order S-06-06 and most recently Executive Order S-01-07 (the Low Carbon Fuel Standard) requiring a 10 percent reduction in the carbon intensity of transportation fuels by 2020. Currently, compressed natural gas (CNG) is used as a petroleum alternative for cars and other light use vehicles. In addition, liquefied natural gas (LNG) is also being developed as a fuel source suitable for heavier industrial vehicles. While new CNG and LNG vehicles are available for commercial purchase, the existing market is relatively small and these alternative fuel vehicles are more costly. In addition, some diesel and other vehicles can be retrofitted to use a natural gas fuel. However, the costs are considerable and even high-use vehicles will have a long payback period from an economic feasibility perspective.

Compressed biomethane (CBM) and liquefied biomethane (LBM) are both potential substitute fuels for CNG and LNG vehicles. However, as with the CNG and LNG markets, although demand has been growing, this alternative fuels market is still at an early stage of development. Currently the majority of CNG and LNG vehicle fleets belong to municipalities. While this may offer some opportunities for partnerships, these will be geographically limited and will have a very finite demand until wider public adoption of CNG or LNG occurs. In addition, greater adoption of CNG and LNG as alternative fuels also faces strong competition from ethanol and biodiesel, which to date have received considerable and greater federal and state support.

Currently, nearly all of the LNG within California is imported over land in its liquid form by truck. Therefore, until planned LNG terminals in Southern California are completed, LBM produced in the Central Valley could have a transportation advantage over LNG. However, it is unclear whether the magnitude of this transportation cost savings will outweigh the higher production costs currently projected for LBM.

Consequently, the market potential for CBM and LBM is far from assured and participation as a fuel provider will face additional production costs (vehicle conversion, possible development of on-site fueling infrastructure). Therefore, given the absence of clear market demand and purchasers, the feasibility of production of CBM or LBM for bio-fuel sale is uncertain since it is difficult to determine the likely market price that producers would actually be able to obtain.

**Overall Digester System Construction Cost Estimates**

As discussed above, the capital costs for manure digester systems’ construction and equipment costs will vary depending on both the size and configuration of the planned system. Irrespective,
even the simplest of manure digester systems are relatively costly. Table 2 shows the costs and grant funding obtained for nine dairy digester systems in California. The cost estimates include the electrical generation facilities. 

**TABLE 2**  
CAPITAL COSTS FOR DAIRY DIGESTER DEVELOPMENTS IN CALIFORNIA

<table>
<thead>
<tr>
<th>Dairy</th>
<th>Digester Type</th>
<th>Size (kW)</th>
<th>Annual Energy Production (KWh)</th>
<th>Debt Capitalization</th>
<th>Grant Equity</th>
<th>Capital Cost (a)</th>
<th>Capital Cost (a) ($/kWh)</th>
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</thead>
<tbody>
<tr>
<td>Hilarides</td>
<td>Covered Lagoon</td>
<td>500</td>
<td>3,383</td>
<td>0%</td>
<td>40%</td>
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<td>Cottonwood</td>
<td>Covered Lagoon</td>
<td>300</td>
<td>2,133</td>
<td>0%</td>
<td>31%</td>
<td>69%</td>
<td>$3,132,000</td>
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<td>Blakes Landing</td>
<td>Covered Lagoon</td>
<td>75</td>
<td>253</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
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<tr>
<td>Castelanelli</td>
<td>Covered Lagoon</td>
<td>160</td>
<td>1,135</td>
<td>0%</td>
<td>57%</td>
<td>43%</td>
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<tr>
<td>Koetsier</td>
<td>Plug Flow</td>
<td>260</td>
<td>540</td>
<td>0%</td>
<td>0%</td>
<td>100% (a)</td>
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<tr>
<td>Van Ommering</td>
<td>Plug Flow</td>
<td>130</td>
<td>489</td>
<td>0%</td>
<td>46%</td>
<td>54%</td>
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<tr>
<td>Meadowbrook</td>
<td>Plug Flow</td>
<td>160</td>
<td>1,100</td>
<td>0%</td>
<td>45%</td>
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<td>IEUA</td>
<td>Modified Mix Plug Flow</td>
<td>943</td>
<td>7,572</td>
<td>0%</td>
<td>1%</td>
<td>99% (a)</td>
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<td>Eden-Vale</td>
<td>Plug Flow</td>
<td>180</td>
<td>457</td>
<td>0%</td>
<td>37%</td>
<td>63%</td>
<td>$904,000</td>
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* Capital Costs have been adjusted for inflation into 2010 dollar terms.
* Koetsier and IEUA received their subsidies as 5 year production payment instead of grant funding.


Other studies report similar cost estimates for developing dairy digester systems. Recent analysis for comparably sized dairy digester systems in Vermont reported capital costs between $4,000 to $7,800 per kWh in 2010 dollar terms (Dowds, 2009). Similarly, the approximate initial total cost for developing a 400kW digester system at Fiscalini Farms in Modesto California was reported to be over $2 million, equivalent to more than $5,000 per kW in 2010 dollar terms (Gannon, 2008). However, subsequent additional design and development requirements resulted in a final system cost of approximately $4 million of which only $1.4 million was obtained from grant funding (Dairy Today, 2010). The Gallo Farms Dairy estimates that the cost of its 700 kW digester system was approximately $3.5 million in 2010 dollar terms which is equivalent to a $5,000 per kWh capital cost (Pacific CHP Application Center, 2010).

As discussed above, digester systems developed for production of biomethane will require considerable additional upgrading equipment to remove the CO₂ and other impurities. In addition, compressor and storage systems will be needed if liquefied or compressed biomethane is to be produced. If the upgraded biomethane is to be injected to the utility pipeline then pipeline injection may require additional on farm (and possibly off-farm) pipeline to the utility’s natural gas transmission line as well as interconnection, controls and monitoring facilities to ensure the quality of gas supplied to the utility.

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27 As discussed earlier, new digester development for electrical production will incur substantially higher equipment costs as more expensive generation system are now required to meet subsequent and more stringent air quality standards limiting NOx emission to 9ppm.
As discussed previously, most current biogas upgrading systems require relatively high gas throughput volumes for optimal performance. Consequently, biomethane production will incur additional costs from both increased scale of production as well as the additional facility and equipment requirements. Industry experts currently maintain that at a minimum manure for 10,000 cows would likely be necessary (without co-digestion) to generate sufficient biogas to supply a biogas upgrade facility to operate efficiently. While dairy farms would not need to invest in electrical generation systems, there would nonetheless be major additional cost for farm-sized biomethane production. Preliminary cost estimates for the CEC project interconnection costs of $250,000 and pipeline costs of at least $50,000 for the existing California digesters (PERI, 2009). The cost for biogas upgrading facilities was estimated to vary from $400,000 to over $750,000 (depending on the plant capacity). The saving from the reduced electrical generation capital cost also varied greatly from as high as $800,000 for Hilarides Dairy to just under a $100,000 for other dairies. Excluding the Blakes Landing and Castelaneli Dairies which were 5 miles or further from a suitable utility connection site, the total net additional capital cost for pipeline injections was generally $500,000 to $700,000 higher than for on-site electrical generation (PEIR, 2009). The study also projected that there would be a 15 percent loss of the original biogas quantity by the upgrading process.

Although preliminary and specific to the existing digester systems, the PERI cost analyses demonstrates the considerable additional capital cost involved in dairy digester development for biomethane production.

**Implementation Factors**

**Farmer Interest**

Dairy production is the core business for dairy farm owners most of whom also must manage some feed-crop production on their farms. Modern dairy farm management is itself a complex business requiring considerable time and expertise to successfully manage milk production and maintain regulatory compliance. This is particularly true during recent years as a poor national economy has adversely affected the California Dairy industry. Although 2008 was a year of record production with high milk prices, in the first half of 2009 dairy producers faced increased production costs – partly from increased feed costs resulting from reduced production as many Midwestern crop farmers shifted their production to feedstock crops for bio-ethanol production. For the first quarter of 2009, the average cost of production for California dairy farmers was $18.51 / cwt. More importantly, as a result of overproduction and reduced foreign demand, milk prices fell by early 40 percent between 2008 and 2009 to $10.47 / cwt - their lowest level since June 2003.

Furthermore, feed expenses represent the majority of the dairy farmer’s cost. In 2005, nearly 58 percent of the average Californian dairy farmer’s total cost of production was spent on feed while less than 3 percent of the total dairy budget was spent on electricity, fuel and lubrications for the farm operations (USDA, 2005). Consequently, the potential direct energy and/or fuel cost savings

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28 For farms located 5 miles from a suitable transmission utility connection site the pipeline cost was $1 million.
29 Except for Hilarides Dairy which had an unexplained but very major cost saving (approximately $788,000 in 2007 dollars terms) for replacement of its electricity generation equipment.
from a digester will represent, at best, a very minor benefit to the farm’s budget and any such savings may be easily outweighed by any feed price changes.

Not only must dairy farmers be willing to accept the necessary investment and operating risk to develop digester systems, farmers must develop the technical capabilities and have sufficient professional interest in assuming the secondary occupation of biogas production (Sempra, 2009).

In the face of such volatility and adverse economic conditions, without clearly attainable net financial earnings, few dairy farmers may be expected to assume the additional costs, risks and responsibilities necessary to develop dairy digesters.

**Capital Availability**

The interest rate associated with the initial capital investment (and to a lesser extent managing the operations cash flow needs) will play an important role in determining digester feasibility. Low interest loans and favorable tax depreciation allowances can have an important contribution in reducing the loan repayment burden that a facility must support.

The useful project life for digester systems will have an important role in affecting the economic feasibility of proposed digester and related biogas treatment facilities. A longer useful life will increase the period over which the facility’s capital investment can be earned back. However, due to the interest and inflation effects to the capital investment, future earnings at later periods in a facility’s operations typically will have a lesser contribution to offsetting the initial capital investment.

There are two key factors determining the availability of capital for farm digester systems. First, the dairy farm’s financial situation will be a fundamental determinant of its ability to borrow capital. The amount of equity that a dairy has in its business, its cash flow and the amount of the loan required will determine the likelihood that the farmer can qualify for a loan. Given the recent financial challenges facing the Californian dairy industry, it is expected that few dairies will be able to qualify for the necessary loans from commercial banks to fund the development of major digester facilities.

In addition to the dairy’s financial position, commercial banks must also be willing to provide the loans. Given the currently tight credit market facing the entire economy and the dairy industry’s current poor market conditions, it may be expected that many banks will be unwilling to provide lending for digesters – especially under relatively favorable terms.

Therefore, due to the challenges facing the dairy industry and the generally weak credit market, few dairies are expected to be in the financial position to fund digester development.

**Third Party Developer Assistance**

Third party developers can be expected to be important for the development of future on-farm or community digester facilities within the Central Valley. As discussed above, most dairy farmers are likely to be unwilling or unable to develop manure digesters systems themselves. Third party developers will likely be better able to collect and manage the investment and have the expertise necessary for effective digester development. The ability for third party developers to negotiate
and manage favorable Small Renewable Generator Power Purchase Agreement (PPA) with utility companies is also likely to be a key advantage for future digester system development.

The commercial interest rates and the related return on investment (ROI) sought by private developers will be important determinants of the economic viability and future development of digester facilities in the Central Valley. The ROI that developers will apply to digester systems will be a function of both commercial interest rates and the profit and risk premiums associated with any digester facility venture. The risk facing developers can be reduced by favorable market conditions (e.g., long term contracts with utilities or other biogas/biomethane consumers) and will also be related the supply conditions (such as the extent that the production technology and equipment is well established, widely adopted and/or transferrable to other commercial uses).

Due to the technological, market and regulatory risks associated with biogas/biomethane production, the returns on investment that potential venture capitalist or other third party developer will seek from any digester investment will be significantly above the returns required for other more established industries or businesses. Within the energy industry, potential investors typically seek payback periods of three to five years (Cheremisinoff, 2010; Best 2010). Within the published digester feasibility studies, the payback periods and return on investment rates applied vary considerable – partly given the differences between financial feasibility analyses (reflecting commercial investors’ profit requirements and capital terms) and economic feasibility studies (that represent agency or public policy perspectives) where the cost of money will be substantially lower and profit earning not applicable. Recent analyses for the California Energy Commission have applied rate of return estimates of 17% for their feasibility analyses (PERI, 2008).

While third party developer participation may be an important component of future digester development, their participation is fundamentally a reflection of the economic feasibility of dairy manure digesters and market context. Consequently, they may be considered to play an major role but will be an indirect economic driver since its will be the fundamentals of other market conditions that will determine the role and extent of their participation in the future digester development within the Central Valley.

**Environment Compliance and Regulatory Requirements**

In general, dairy operators face increasingly stringent state environmental regulations requiring dairy operators to adopt more advanced methods to manage their operations. The requirements of Senate Bill (SB) 700, San Joaquin Valley Air Quality Management District (SJAQMD) air quality regulations and Central Valley Water Board (CVWB) waste discharge regulations are examples of such rules. Anaerobic digesters, composting systems and other more costly waste management approaches are replacing traditional land application of dairy manure as accepted manure management practices. Consequently, if the economic returns of digester systems can be improved, then their greater implementation can be encouraged, which in turn will result in overall reduced air and water quality impacts.
**Water Quality Compliance**

Until relatively recently, most dairies located within the Central Valley Water Board jurisdiction operated under a waiver of waste discharge requirements. In May 2007, the Central Valley Water Board adopted Order No. R5-2007-0035 (Waste Discharge Requirements General Order for Existing Milk Cow Dairies). The order serves as general waste discharge requirements for discharges of waste from existing milk cow dairies and requires dairies to submit a Report of Waste Discharge prior to construction of an anaerobic digester.

The additional water quality requirements in the order have added considerable costs and restrictions. Farmers are now required to manage their applications of nutrients to their farmlands and otherwise protect their groundwater resources. The key water quality concerns for dairy digester systems are the potential for adverse groundwater impacts from dairy waste or digestate stored within farm lagoon systems and the added salt and nitrates from the importation of co-digester feedstock. The CVWB estimates that a typical 1,000 herd dairy produces approximately 3,600 tons (dry weight) of manure per year containing 180 tons of nitrogen and 235 tons of inorganic salts (CVWB, 2007).

Unless, landowners can prove that their farm’s specific site conditions will not result in water quality impacts, the primary compliance approach will be construction of more expensive Tier 1 lagoon systems. Currently, the CVWB is in the process of completing a comprehensive salinity management program with the State Water Board to address salinity problems within the Central Valley. However, until the new plan and program is completed, there are no general salt standards. Consequently, review of dairy farm waste discharge compliance plans are performed on a case by case basis and the salt impacts of co-digester digestate are poorly understood, making it more difficult and costly for dairy farmers to comply with the water quality requirements.

Depending on the specific soil and groundwater conditions, some farms are required to install doubled lined lagoons (e.g., Tier 1) and/or reduce their application rates of liquid digestate or solid manure to comply with the state regulations. Salt accumulation issues within the Central Valley are likely to persist and there are currently limited management options for reducing the potential water quality impacts associated with accumulated salts.

Current regulatory differences between dairy and non-dairy farms also limit the ability for dairy farmers to export their manure or digestate to neighboring farms. While exportation of solid manure and/or digestate to other farms is permitted with little water quality regulatory oversight, a similar transfer of digestate effluent requires the recipient farm to comply with the WDR manure management testing and verification procedures. Although the recipient farmer could beneficially use the effluent to meet its fertilizer needs, faced with the regulatory requirements many farmers will instead elect to purchase and apply chemical fertilizer. The resulting outcome adds new nitrates locally (i.e., from the chemical fertilizer use) and reduces the options for manure digester operators to manage their nitrate load. In particular, wet system digesters (e.g., covered lagoons) that can not use all their digestate on site will likely have to reduce the water content of their effluent if the dairy farmer needs to export some of the material to meet the water quality standards. In which case, for the farmer to make the off-site transfer it will face added costs, energy use and water losses. Such offsite liquid

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30 Central Valley Salinity Alternatives for Long-Term Sustainability (CV-SALTS)
digestate transfer issues could potentially be an even more significant regulatory issue for a community digester or co-digester operation (Martin, P., 2010).

**Air Quality**

The California Air Resources Board (CARB) is responsible for regulating air emissions within the state. CARB is the lead agency for implementing the AB32 Scoping Plan which is the action plan for California to reduce it greenhouse gas emission substantially by 2020 with additional reduction by 2050. California farms were generally exempted from air quality regulations until the enactment of SB700 in 2003, which required most dairy farmers and other large confined animal feeding operations (CAFO) to obtain air quality permits for their operations from the local air district. Although rules vary between air districts, dairies that require air permits are now generally treated like other industries.

The San Joaquin Valley Air Pollution Control District has implemented several rules that apply to dairy operations including Rule 4550 (Conservation Management Practices [CMO] Plans), and Rule 4570 (Confined Animal Facilities). In the SJVAPCD new and modified dairies are subject to the New Source Review Rule – District Rule 2201, which requires Best Available Control Technology (BACT), Public Notice, Health Risk Assessment (HRA) & Ambient Air Quality Analyses (AAQA). For the SJVAPCD to issues permits, the projects are also required to comply with the California Environmental Quality Act (CEQA).

While the dairies are adapting to the new rules, the New Source Review Rule BACT requirements for NOx and SOx emissions from electrical generation equipment are cited as a real economic challenge for the dairies. There are several approaches to electrical generation but the systems are expensive to operate and poorly suited for dairy biogas or biomethane use.

The following is detailed updated information from Ramon Norman at the SJVAPCD describing the current requirements related to strict NOx emission limits (Norman, 2010).

“For projects proposing to generate power from biogas in the San Joaquin Valley, the main pollutants that the District is concerned about are NOx and SOx. This is because these pollutants are precursors to ozone (NOx) and particulate matter (NOx and SOx). The San Joaquin Valley Air basin will soon be classified as extreme non-attainment for the Federal 1-hour ozone standard (and the now revoked Federal 8-hour ozone) standard - the worst classification. The San Joaquin Valley Air basin is also classified as non-attainment for the Federal PM2.5 standard. Because of the air quality problems in the San Joaquin Valley and reductions in NOx are critical to the District’s attainment strategy, the District is now requiring more stringent emission controls (such as catalysts) for biogas-fired engines and evaluating alternative equipment (fuel cells, microturbines, etc.) to further reduce NOx emissions down to 0.15 g/bhp-hr (around 9-11 ppmvd @ 15% O2) or less as BACT for these operations. This BACT level has been in place for fossil fuel-fired engines in the District for a number of years but the District is just beginning to apply this BACT level to biogas-fired engines. To meet the District BACT for NOx from these installations, controls (catalysts) would need to be added to an engine or an alternate technology, such as microturbines or fuel cells, would need to be used. Because the San Joaquin Valley is classified as non-attainment for the Federal PM2.5 standard and SOx is an important precursor for PM2.5, emissions of SOx must also be
minimized. To meet the District BACT for SOX from these installations, scrubbing of the
gas to remove H2S (down to 50 ppmv) prior to combustion will also be required. Because
the San Joaquin Valley Air District is classified as attainment for the CO Ambient Air
Quality Standard, BACT is usually not triggered for CO and engines would only be
required to meet the 2,000 ppmvd CO limit from District Rule 4702.

At a minimum, any flares proposed for a digester system would need to satisfy the "Achieved
in Practice" Category in the District's BACT Guidelines, which currently require a low-
NOX flare with NOX emissions ≤ 0.06 lb/MMBtu. Any flares proposed for a digester would
also need to satisfy the requirements of District Rule 4311, which requires enclosed flares
to meet certain NOX and VOC emission limits and to be source-tested annually. Open flares
(air-assisted, steam-assisted, or non-assisted) with flare gas pressure is less than 5 psig must
be operated in such a manner that meets the control device requirements of 40 CFR 60.18.
Emergency flares, which are exempt from the previous previsions, are required to maintain
records of the duration of flaring events, the amount of gas burned, and the nature of the
emergency. The requirements of District Rule 4311 can be found at the following link:


Any boilers or process heaters proposed for a digester system and rated 5.0 MMBtu/hr or
greater would need to satisfy the requirements of District Rule 4320, which requires
biogas-fired units to meet a NOX emission limit of 12 ppmv @ 3% O2 and also requires
periodic source testing and emission monitoring. The requirements of District Rule 4320
can be found at the following link: http://www.valleyair.org/rules/currntrules/r4320.pdf.”

Mr. Norman also provided a list of suppliers of equipment that may be able to satisfy the District's
BACT requirement for NOX from power generating equipment that combusts biogas (Norman, 2010).

Inter-Agency Co-operation and Co-ordination

Fundamentally, there is a major challenge for finding a mechanism and forum for facilitating inter-
agency co-operation and co-ordination. From a comprehensive cross resource perspective, manure
digesters are generally recognized to offer significant net environmental benefits. However, since
these benefits extend across several resource areas (i.e., air, water and energy use) and are not
fully recognized by market mechanisms (e.g., odor and greenhouse gas reductions) balancing impact
tradeoffs remains difficult. Currently methane emissions from dairy operations are not regulated.

As a result, while the negative air quality impacts of the NOx emissions are recognized, the
supporting (albeit different and less localized) air quality benefits of the methane destruction
are not. Furthermore, there is not an easy mechanism for valuing the societal tradeoff of the beneficial
energy capture (i.e., the produced electricity) from a resource that otherwise would have its entire
energy resource value lost.

The complicated regulatory environment facing dairy operators is widely considered to be a major
obstacle to future anaerobic digester development within the Central Valley. Several industry
participants and analyses recommend that continued CEC and CPUC support to address technical
and commercial risks is important for future development of manure digester systems in the Central
Valley (Dusault, 2010). Improvement to the permitting process for complex projects with cross
resource impacts such as anaerobic digesters is generally recognized as important and necessary for encouraging future development of manure digesters. A centralized and stream-lined permit process that reduces the regulatory burden would greatly facilitate future dairy digester development.

Utility Cooperation

There is currently some mismatch between utilities' interests and needs for digester development. Although there are some regulatory restrictions to utilities, there are many potential opportunities for a supportive utility role to bridge the existing market gaps and barriers to digester development. Support by utilities in this early stage of market development could have a significant positive role. Potential for utility participation in future projects is particularly important for the biomethane conditioning projects. SoCalGas is investigating the feasibility of potential cooperation and involvement in future biomethane production projects for pipeline injection with Sempra Energy (Goodman, 2010).

Several experts suggested that the market for future biogas would be improved if utilities such as PG&E were willing to invest, operate and maintain the necessary upgrading facilities required for pipeline injection. While such an approach would reduce the technical and investment burden on third party or dairy digester owners, the significant production costs for pipeline injection would remain high as only minimal savings would be potentially gained by reducing the utility need for verification of the non-utility injected biomethane quality. In addition, the location constraints of biogas acquisition in relative proximity to the utility transmission system would also remain.

Under the current market and regulatory conditions, there is little incentive for PG&E or other utilities to assume the additional costs, risks and responsibilities. Indeed, it may be expected that CPUC approval would be necessary for PG&E to undertake any such biogas development projects and pass on the costs to ratepayers.

Emerging Technologies and Market

As discussed above, the economic viability of future digester development appears currently to be primarily constrained by the comparatively low commodity prices for natural gas and electricity coupled by the relatively high costs of production. The complicated and cross resource impacts associated with dairy digester systems result in costly compliance requirements. Unless major breakthrough technological improvements are achieved, it is considered likely that manure digester production will remain economically unfeasible without government support for the foreseeable future. Furthermore, future improvements in feasibility would be expected to be minimal and incremental as long as natural gas and electrical prices remain relatively stable in real terms.

There is considerable hope within the renewable resource industry that fuel cells, “micro-scrubbers,” or other new technological improvements may be possible that could reduce unit production costs for biogas and/or biomethane production or enable affordable on-site electrical production that complies with air quality requirements.

31 It is likely that the utility would nonetheless need to evaluate biogas quality
Similarly, the economic feasibility for biogas production is presently reduced by the currently limited market for CBM and LBM as a transportation biofuel. Major growth in commercial and/or consumer natural gas vehicles (and the necessary related fueling infrastructure) would likely represent a new market and demand for CBM and/or LBM. In which case, dairy manure production of CBM and/or LBM might be able to take advantage of some comparative advantage of local production (especially over LBM will currently is mostly imported into California at some cost either by road or rail). However, until these biofuel markets develop or other major technical advances actually occur, the economic feasibility of dairy manure digesters can be expected to remain difficult without adequate governmental and/or regulatory assistance.

**Analysis Caveats**

The previous economic assessment is based on research and interviews during a highly dynamic period for the digester and other renewable energy industries. As outlined above, there are many unknown variables facing the industry – both technological and regulatory. Consequently, quantitative analysis of the industry economics is particularly challenging and, if imbedded assumptions or factors are not recognized, any finding can be misleading or highly prone to misinterpretation.

Furthermore, most digester analyses are very site and technology-specific. In addition, most operating digester projects have been pilot or demonstration projects that have received considerable government assistance. As a result, there is extensive complexity associated with any efforts to normalize the design, costs and performance of digesters operating under very different circumstances.

Consequently, we have used a predominantly qualitative approach since the primary purpose for this economic assessment has been to provide a framework by which the key economic drivers can be distinguished from the numerous variables and other factors that have a more indirect and lesser contribution to dairy digester feasibility.

**References**


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32 However, successful development of the proposed Clearwater and/or Port Esperanza LNG terminals in Southern California would be expected to reduce the potential locational advantage for future LBM production.


CH2M Hill, Making Renewables Part of an Affordable and Diverse Electric System in California, 2007.


Clear Horizons, Craven Brothers Farm Digester Project Feasibility Study, January 2006.


LaMendola, T. Personal Communication, April 2010.


Norman, Ramon, Air Quality Engineer, email to Tim Morgan at ESA, February 4, 2010.


Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<td>AB</td>
<td>Assemble Bill</td>
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<tr>
<td>ACEEE</td>
<td>American Council for an Energy Efficient Economy</td>
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<td>BACT</td>
<td>Best Available Control Technology</td>
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<td>CAFO</td>
<td>Confined Animal Feeding Operations</td>
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<td>CARB</td>
<td>California Air Resources Board</td>
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<td>CBG</td>
<td>Compressed Biomethane</td>
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<td>CCAR</td>
<td>California Climate Action Registry</td>
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<tr>
<td>CEC</td>
<td>California Energy Commission</td>
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<td>CHP</td>
<td>Combined Heat and Power</td>
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<td>CNG</td>
<td>Compressed Natural Gas</td>
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<td>DG</td>
<td>Distributed Generation</td>
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<td>ERB</td>
<td>Emerging Renewables Program</td>
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<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>IC</td>
<td>Internal Combustion</td>
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<td>IEUA</td>
<td>Inland Empire Utilities Agency</td>
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<td>LCFS</td>
<td>California Low Carbon Fuel Standard</td>
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<td>LBM</td>
<td>Liquefied Biomethane</td>
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<td>LNG</td>
<td>Liquefied Natural Gas</td>
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<tr>
<td>MPR</td>
<td>Market Price Referent</td>
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<tr>
<td>NCRS</td>
<td>Natural Resource Conservation Service</td>
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<tr>
<td>PIER</td>
<td>Public Interest Energy Research Program</td>
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<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
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<td>ppm</td>
<td>Parts per million</td>
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<td>PSA</td>
<td>Pressure Swing Absorption</td>
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<td>REC</td>
<td>Renewable Energy Credits</td>
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<td>RPS</td>
<td>Renewable Portfolio Standards</td>
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<td>TAG</td>
<td>Technical Advisory Group</td>
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<tr>
<td>WDR</td>
<td>Waste Discharge Requirements</td>
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Glossary

Aerobic Bacteria: Bacteria that require free elemental oxygen to sustain life.
Aerobic: Requiring, or not destroyed by, the presence of free elemental oxygen.
AgSTAR: A voluntary federal program that encourages the use of effective technologies to capture methane gas, generated from the decomposition of animal manure, for use as an energy resource.
Anaerobic: Requiring, or not destroyed by, the absence of air or free oxygen.
Anaerobic Bacteria: Bacteria that only grow in the absence of free elemental oxygen.
Anaerobic Lagoon: A treatment or stabilization process that involves retention under anaerobic conditions.
Anaerobic: A tank or other vessel for the decomposition of organic matter in the absence of elemental oxygen.
Anaerobic Digestion: The degradation of organic matter including manure brought about through the action of microorganisms in the absence of elemental oxygen.
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
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<tr>
<td>Best Management Practice (BMP)</td>
<td>A practice or combination of practices found to be the most effective, practicable (including economic and institutional considerations) means of preventing or reducing the amount of pollution generated by nonpoint sources to a level compatible with water quality goals.</td>
</tr>
<tr>
<td>Biogas</td>
<td>Gas resulting from the decomposition of organic matter under anaerobic conditions. The principal constituents are methane and carbon dioxide.</td>
</tr>
<tr>
<td>Biomass</td>
<td>Plant materials and animal wastes used especially as a source of fuel.</td>
</tr>
<tr>
<td>British Thermal Unit (BTU)</td>
<td>The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. One cubic foot of biogas typically contains about 600 to 800 BTUs of heat energy. By comparison, one cubic foot of natural gas contains about 1,000 BTUs.</td>
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<td>Carbon Offset (Carbon Credit)</td>
<td>A carbon offset purchase results in a reduction or avoidance of greenhouse gas emissions. The purchaser of the carbon offset entity pays the seller not to emit or otherwise reduce the agreed amount of emissions. This may be achieved through various kinds of projects including renewable energy, methane capture, reforestation, improved energy efficiency, etc. A key characteristic of a carbon offset is that it must be “additional” i.e. the offset provider must prove that the project would not have happened without its financial investment, and that the project goes beyond “business as usual” activity.</td>
</tr>
<tr>
<td>Complete Mix Digester</td>
<td>A controlled temperature, constant volume, mechanically mixed vessel designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.</td>
</tr>
<tr>
<td>Composting</td>
<td>The biological decomposition and stabilization of organic matter under conditions which allow the development of elevated temperatures as the result of biologically produced heat. When complete, the final product is sufficiently stable for storage and application to land without adverse environmental effects.</td>
</tr>
<tr>
<td>Covered Lagoon Digester</td>
<td>An anaerobic lagoon fitted with an impermeable, gas- and air-tight cover designed to capture biogas resulting from the decomposition of manure.</td>
</tr>
<tr>
<td>Demand charge</td>
<td>The peak kW demand during any quarter hour interval multiplied by the demand charge rate.</td>
</tr>
<tr>
<td>Digestate</td>
<td>The sludge or spent slurry discharged from a digester. In this report digestate generally refers to the dewatered solids portion of the spent slurry, rather than the liquid digestate, which is referred to as the effluent.</td>
</tr>
<tr>
<td>Digester</td>
<td>A concrete vessel used for the biological, physical, or chemical breakdown of livestock and poultry manure.</td>
</tr>
<tr>
<td>Discount rate</td>
<td>The interest rate used to convert future payments into present values.</td>
</tr>
<tr>
<td>Down payment</td>
<td>The initial amount paid at the time of purchase or construction expressed as a percent of the total initial cost.</td>
</tr>
<tr>
<td>Drystack</td>
<td>Solid or dry manure that is scraped from a barn, feedlane, drylot or other similar surface and stored in a pile until it can be utilized.</td>
</tr>
<tr>
<td>Effluent</td>
<td>The discharge from an anaerobic digester or other manure stabilization process.</td>
</tr>
<tr>
<td>Energy Charge</td>
<td>The energy charge rate times the total kWh of electricity used.</td>
</tr>
<tr>
<td>Fats</td>
<td>Any of numerous compounds of carbon, hydrogen, and oxygen that are glycerides of fatty acids, the chief constituents of plant and animal fat, and a major class of energy-rich food. “Fats are a principal source of energy in animal feeds and are excreted if not utilized.”</td>
</tr>
<tr>
<td>Fixed Film Digester</td>
<td>An anaerobic digester in which the microorganisms responsible for waste stabilization and biogas production are attached to some inert medium.</td>
</tr>
<tr>
<td>Flushing System</td>
<td>A manure collection system that collects and transports manure using water.</td>
</tr>
<tr>
<td>Greenhouse Gas</td>
<td>An atmospheric gas, which is transparent to incoming solar radiation but absorbs the infrared radiation emitted by the Earth’s surface. The principal greenhouse gases are carbon dioxide, methane, and CFCs.</td>
</tr>
<tr>
<td>Hydraulic Retention Time (HRT)</td>
<td>The average length of time any particle of manure remains in a manure treatment or storage structure. The HRT is an important design parameter for treatment lagoons, covered lagoon digesters, complete mix digesters, and plug flow digesters.</td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>The annual rate of increase in costs or sales prices in percent.</td>
</tr>
<tr>
<td>Influent</td>
<td>The flow into an anaerobic digester or other manure stabilization process.</td>
</tr>
</tbody>
</table>
## Key Factors Determining Economic Feasibility

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Internal Rate of Return</td>
<td>The discount rate that makes the NPV of an income stream equal to zero.</td>
</tr>
<tr>
<td>Kilowatt (KW)</td>
<td>One thousand watts (1.341 horsepower).</td>
</tr>
<tr>
<td>Kilowatt Hour (kWh)</td>
<td>A unit of work or energy equal to that expended by one kilowatt in one hour or to 3.6 million joules. A unit of work or energy equal to that expended by one kilowatt in one hour (1.341 horsepower-hours).</td>
</tr>
<tr>
<td>Lagoon</td>
<td>Any large holding or detention pond, usually with earthen dikes, used to contain wastewater while sedimentation and biological treatment or stabilization occur.</td>
</tr>
<tr>
<td>Land Application</td>
<td>Application of manure to land for reuse of the nutrients and organic matter for their fertilizer value.</td>
</tr>
<tr>
<td>Liquid Manure</td>
<td>Manure having a total solids content of no more than five percent.</td>
</tr>
<tr>
<td>Loading Rate</td>
<td>A measure of the rate of volatile solids (VS) entry into a manure management facility with methane recovery. Loading rate is often expressed as pounds of VS/1000 cubic feet.</td>
</tr>
<tr>
<td>Loan Rate</td>
<td>The percent of the total loan amount paid per year.</td>
</tr>
<tr>
<td>Manure</td>
<td>The fecal and urinary excretions of livestock and poultry.</td>
</tr>
<tr>
<td>Mesophilic</td>
<td>Operationally between 80°F and 100°F (27°C and 38°C).</td>
</tr>
<tr>
<td>Methane</td>
<td>A colorless, odorless, flammable gaseous hydrocarbon that is a product of the decomposition of organic matter. Methane is a major greenhouse gas. Methane is also the principal component of natural gas.</td>
</tr>
<tr>
<td>Minimum Treatment Volume</td>
<td>The minimum volume necessary for the design HRT or loading rate.</td>
</tr>
<tr>
<td>Mix Tank</td>
<td>A control point where manure is collected and added to water or dry manure to achieve the required solids content for a complete mix or plug flow digester.</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>A combustible mixture of methane and other hydrocarbons used chiefly as a fuel.</td>
</tr>
<tr>
<td>Net Present Value (NPV)</td>
<td>The present value of all cash inflows and outflows of a project at a given discount rate over the life of the project.</td>
</tr>
<tr>
<td>NPV Payback</td>
<td>The number of years it takes to pay back the capital cost of a project calculated with discounted future revenues and costs. Profitable projects will have an NPV Payback value less than or equal to the lifetime of the project.</td>
</tr>
<tr>
<td>Nutrients</td>
<td>A substance required for plant or animal growth. The primary nutrients required by plants are nitrogen, phosphorus, and potassium. The primary nutrients required by animals are carbohydrates, fats, and proteins.</td>
</tr>
<tr>
<td>Operating Volume</td>
<td>The volume of the lagoon needed to hold and treat the manure influent and the rain-evap volume.</td>
</tr>
<tr>
<td>Payback Years</td>
<td>The number of years it takes to pay back the capital cost of a project.</td>
</tr>
<tr>
<td>Plug Flow Digester</td>
<td>A constant volume, flow-through, controlled temperature biological treatment unit designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.</td>
</tr>
<tr>
<td>Point Source Pollution</td>
<td>Pollution entering a water body from a discrete conveyance such as a pipe or ditch.</td>
</tr>
<tr>
<td>Process Water</td>
<td>Water used in the normal operation of a livestock farm. Process water includes all sources of water that may need to be managed in the farm’s manure management system.</td>
</tr>
<tr>
<td>Proteins</td>
<td>Any of numerous naturally occurring extremely complex combinations of amino acids containing the elements carbon, hydrogen, nitrogen, and oxygen. Proteins are in animal feeds are utilized for growth, reproduction, and lactation and are excreted if not utilized.</td>
</tr>
<tr>
<td>Renewable Energy Credits (RECs)</td>
<td>Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.</td>
</tr>
<tr>
<td>Scrape System</td>
<td>Collection method that uses a mechanical or other device to regularly remove manure from barns, confine buildings, drylots, or other similar areas where manure is deposited.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Simple Payback</td>
<td>The number of years it takes to pay back the capital cost of a project calculated without discounting future revenues or costs.</td>
</tr>
<tr>
<td>Slurry (Semi-solid) Manure</td>
<td>Manure having a total solids content between five and ten percent.</td>
</tr>
<tr>
<td>Solids Manure</td>
<td>Manure having a total solids content exceeding 10 percent.</td>
</tr>
<tr>
<td>Storage Pond</td>
<td>An earthen basin designed to store manure and wastewater until it can be utilized. Storage ponds are not designed to treat manure.</td>
</tr>
<tr>
<td>Storage Tank</td>
<td>A concrete or metal tank designed to store manure and wastewater until it can be utilized. Storage tanks are not designed to treat manure.</td>
</tr>
<tr>
<td>Straight-Line Depreciation</td>
<td>Depreciation per year equals the total facility cost divided by the years of depreciation (usually the facility lifetime).</td>
</tr>
<tr>
<td>Supplemental Heat</td>
<td>Additional heat added to complete mix and plug flow digester to maintain a constant operating temperature at which maximum biological treatment may occur.</td>
</tr>
<tr>
<td>Technical Advisory Group (TAG)</td>
<td>A working group of individual representing several California State Agencies and companies knowledgeable and interested in the Environmental Impact Report (EIR) being prepared for Dairy Manure Digester and Co-digester Facilities. The group is scheduled for four meetings and will review various background documents that will help to support the preparation of the EIR.</td>
</tr>
<tr>
<td>Thermophilic</td>
<td>Operationally between 110°F and 140°F (43°C and 60°C).</td>
</tr>
<tr>
<td>Total Solids</td>
<td>The sum of dissolved and suspended solids usually expressed as a concentration or percentage on a wet basis.</td>
</tr>
<tr>
<td>Utility Interconnection</td>
<td>The method of utilizing electricity produced from manure management facilities. Options include either (1) on farm first use then sale to utility or (2) sale to the utility then direct purchase.</td>
</tr>
<tr>
<td>Volatile Solids</td>
<td>The fraction of total solids that is comprised primarily of organic matter.</td>
</tr>
<tr>
<td>Volatilization</td>
<td>The loss of a dissolved gas, such as ammonia, from solution.</td>
</tr>
<tr>
<td>Volumetric Loading Rate</td>
<td>The rate of addition per unit of system volume per unit time. Usually expressed as pounds of volatile solids per 1,000 cubic feet per day for biogas production systems.</td>
</tr>
</tbody>
</table>
Dear Jennifer:

I do have a few comments on the category of the “Complete Mix System”

My comments are specific to the Induced Blanket Reactor (IBR) which did fall under your original definition of complete mix digester. The expanded description does not provide a description accurately establishing the parameters for which the IBR can operate.

As shown in the attached installation descriptions the HRT can be as low as 4 days, not the 15 to 20 days stated.

The IBR does not require “applied energy to operate”. Mixing energy is the result of rising gasses formed in the bottom of the IBR. Given that the IBR is a complete mix without mixing parasitic load the statement regarding expense of the system is not accurate.

Of course the statement “Currently only a few complete mix digester systems operate within California” is completely misleading. There are few dairy complete mix digesters, but when you include municipal wastewater, complete mix is the dominate process in the State.

Attached are a few operational IBR project descriptions, including one in California which will substantiate the above. The Pixley systems recently received a grant from the CEC to expand. The CEC grant will make the Pixley dairy digester one of the largest in the United States. Your documentation should reflect the digestive technology of such a system.

Larry T. Buckle, PE
Organic Energy Corporation, Inc.
1017 L Street #296
Sacramento, CA 95814-3505
USA

8/20/2010
--- On Sat, 5/15/10, Jennifer Tencati <j.tencati@circlepoint.com> wrote:

From: Jennifer Tencati <j.tencati@circlepoint.com>
Subject: Revised Economic Feasibility Report
To: "Jennifer Tencati" <j.tencati@circlepoint.com>
Cc: "Paul Miller" <PMiller@esassoc.com>, "Stephen Klein" <sklein@waterboards.ca.gov>
Date: Saturday, May 15, 2010, 8:16 AM

Dear TAG members,

Attached, please find a revised copy of the Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report. This updated report includes comments from the CPUC, utilities and others who participated in a review of the earlier draft report in San Francisco on April 26th. We appreciate everyone’s insights and efforts in the review process.

Please provide any final comments you may have on the report to me by Monday, May 24th. Comments can be submitted by email to j.tencati@circlepoint.com or by fax to (916) 658-0189.

If you have any questions about the report or the Dairy Digester project, please give me a call at (916) 658-0180 x131.

Kind regards,
Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

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Please think of the environment before you print this email
Jer-Lindy Farm
Brooten, MN

Facility: Dairy – Approximately 135 Cows Serviced

Started (one tank): June, 2008

Input Material: Manure slurry
Collection: Scrape/flush
Substrates Added: Cheese Whey
Typical Manure Solids Content: 6%
Hydraulic Retention Time: Approximately 4.5 days
Throughput During Operation: Approx. 7,100 gallons/day
Gas Production (manure only): 7-8 CFM without substrate
Gas Usage: Electrical Generation
Liquid Effluent: To lagoon for irrigation
Solids: Post digestion separation for bedding
Typical Operating Temperature: 103 deg. F
Westpoint Dairy
Jerome, ID

Facility: Dairy – Approximately 4,500 Cows

First Started (15 tanks): Spring 2009

Input Material: Manure slurry
Collection: Scrape and vacuum
Substrates Added: None
Typical Solids Content: 6.5%
Hydraulic Retention Time: Approximately 4 days
Gas Production: 150 CFM (Est.)
Gas Usage: Gas conditioning and sale
Liquid Effluent: To lagoon for irrigation
Solids: Post digestion separation and sale

Appendix A-242
Souza Farm  
Pixley, CA

Facility: Dairy – Approximately 4,000 Cows

Started (two tank – phase 1 pilot): Summer, 2008  
Expansion to 16 Tanks – Start Q1 2010

Input Material: Manure slurry  
Collection: Vacuum  
Substrates Added: Cheese Whey (oil planned)  
Typical Manure Solids Content: 6%  
Hydraulic Retention Time: Approximately 5 days  
Gas Production (manure only): N/A  
Gas Usage: Flare  
Liquid Effluent: To lagoon for irrigation  
Solids: Post digestion separation for bedding (planned)
Anaerobic Digestion Variants in the Treatment of Solid Wastes

Rational approaches will determine whether microbial methanogenesis can efficiently address solid waste challenges

Melvin S. Finstein

The United States Environmental Protection Agency defines municipal solid waste (MSW) as everyday items, including product packaging, grass clippings, furniture, clothing, bottles, food scraps, newspapers, appliances, and batteries. Over two-thirds of the 254 million tons of MSW produced in 2007 was biodegradable. However, as a practical matter, only about one-third of the biodegradable material would have been amenable to anaerobic digestion, in part because much of the paper was usefully recycled and yard trimmings were composted. Otherwise, it is the extreme heterogeneity of MSW and the difficulties of separating its components that are key obstacles to energy recovery from this waste stream via microbiological processing (Fig. 1).

Source-separation programs targeting food waste and other organics are gaining popularity in the U.S. Compared to mixed MSW, such waste streams need less facility-level removal of non-biodegradable inclusions. Organics-rich waste streams are currently composted, but could be anaerobically digested with the recovery of energy.

Because solid wastes are complex mixtures, anaerobic digestion facilities necessarily include three major components: a mechanical step to recover recyclable materials and remove non-processible inclusions for disposal; an anaerobic digestion step to transform the organics to biogas (methane, carbon dioxide, and trace contaminants), leaving slow-to-degrade residual material usable as compost and liberated water; and a third step to separate residual solids and water and to condition the biogas as necessary. After contaminant removal, the biogas can be used directly to generate electricity on site, or the carbon dioxide can be removed and the methane can be injected into pipelines or used as vehicular fuel.

In France, Germany, and Spain, anaerobic digestion has found a role in the management of MSW. In the United States, some cities and counties have sponsored studies of alternatives to the dominant practices of incineration and landfilling. Although the reports identify anaerobic digestion as a top candidate, no plant has been built. Moreover, technical evaluations focus on mechanics instead of facing more fundamental microbiological-level process design and control issues. Because there are so many ways to configure anaerobic digestion technologies, commercial development awaits decision-making based on meaningful microbiology-based analysis.

Summary

- The heterogeneity of solid waste and difficulties in separating its components are key obstacles to the anaerobic digestion of its biodegradable organic fraction.
- Because anaerobic digestion can be physically configured in different ways, microbiology-based analysis is essential to commercial development.
- Optimizing anaerobic digestion depends on balancing both production and consumption of hydrogen and acids.
- Anaerobic digestion variants embody critical microbiological-level design differences.

Melvin S. Finstein is Professor Emeritus, Department of Environmental Sciences, Rutgers University. He resides in Wheeling, W.V. e-mail, finstein@envsci.rutgers.edu.
Methanogenesis Is a Key Part of Global Carbon Cycle

The degradative part of the global carbon cycle in anaerobic environments generates methane, as can be demonstrated by the “Volta experiment” (http://www.youtube.com/watch?v=e2Gz-h33HCE; Volta experiment courtesy of Craig Phelps). Thus methanogenesis occurs spontaneously in, among other places, organics-rich sediments, landfills, and anaerobic digestion plants whether or not they are rationally designed. However, inefficient, empirical practices are not sufficient for large-scale waste processing.

How well an anaerobic digestion system performs is determined by the rate and extent of degradation, reflected in the amount of methane produced and the stability of the residual digestate. The amount of methane is inversely related to the amount of digestate but directly related to the digestate’s stability. Thus degradative rate and extent need to be taken into account in conjunction with a variety of other factors, including odor prevention, the area that a treatment facility occupies, reactor height and diameter, economic feasibility, public acceptability, and costs of construction and operation. All depend, ultimately, on how the microbes are managed.

Anaerobic digestion has long been used in treating sewage sludge, where process design and control are stubbornly empirical and tradition-bound. Moreover, owing to pilot programs in which food waste is injected into sewage sludge digesters with excess capacity, outmoded practices may spill over into the solid waste domain.

In contrast, a generic reactor design and informed process control strategy is widely used for treating aqueous industrial wastewaters, including those from breweries. These systems reflect a sound understanding of microbial methanogenesis. While not directly applicable to treating solid wastes or waste streams laden with particulate solids, this generic approach provides a model for the more problematic solid waste domain.

Factors in Achieving Fast Microbial Methanogenesis

Methanogenesis is one of the most ancient biological functions on earth, and one of the best understood. Diverse microorganisms partly digest a range of complex solid materials, leading toward the final steps in which methane is generated (Fig. 2). Microorganisms in nature typically degrade relatively low concentrations of organic carbon compounds at a relaxed pace.
However, the idea behind anaerobic digestion—harnessing methanogenesis in engineered reactors—is to intensively transform concentrated wastes as rapidly as possible into methane and degraded residual. The goal is to get the most bang for the volumetric buck by accelerating the process.

Several factors help to explain why particular approaches to reactor design and control might achieve high degradation rates and why others will not. First, acidogens are fast growers. However, some of them, particularly those that transform butyrate and propionate to hydrogen, carbon dioxide, and acetate, are subject to feedback inhibition when hydrogen gas accumulates to even very low levels. In contrast, methanogens are intrinsically slow growers, and are inhibited at acidic pH values. Thus, to achieve overall high rates, both the production and consumption of hydrogen and acids should be in balance, with production matched by consumption. An imbalance causes a bottleneck that reverberates through the metabolic web, slowing overall degradation of waste.

Second, microbial methanogenesis depends on syntrophy in which one species consumes the products of another; interspecies hydrogen transfer, the particular form of syntrophy in which acetogens and methanogens produce and consume hydrogen and acetate; and consortiums, in which acetogens and methanogens form close associations leading to methane production. The more intimate the association, the shorter the diffusive distance, making the syntrophy more efficient.

Third, there are technological hurdles to overcome before methane-producing consortia can be optimally harnessed to degrade wastes on an industrial scale. Process design and control imperatives include the promotion of consortia development and the protection of their integrity. Also, the consortia need to be retained in the reactor, as in the form of an expanded bed or blanket, and the reactor should be designed to allow high organic loading rates, albeit not so high as to upset the balance between acidogens and methanogens.

Diverse Designs Are Being Used or Proposed to Treat Solid Wastes
Several anaerobic systems are in use or projected to treat solid wastes, and they embody critical differences (Table 1). Upflow anaerobic sludge blanket digestion (UASB) is a rational technology in that it is based on the science of microbial methanogenesis and informed by factors needed to achieve high rates. It fosters the development and retention of methanogenic consortia, which self-organize into granules slightly denser than

---

**FIGURE 2**

Major pathways leading to the generation of methane. Adapted from L.T. Argenten and B.A. Wrenn. 2008. Optimizing Mixed-Culture Bioprocessing to Convert Waste into Bioenergy. Chapter 15, p. 179–194, in Bioenergy (eds. J.D. Wall, C.S. Harwood, A. Demain) ASM Press, Washington, D.C. This flow chart was derived, in turn, from earlier reports. The arrows represent: 1. hydrolysis by a vast and diverse array of Eucarya and Bacteria, principally the latter; 2. fermentation of monomers to volatile fatty acids and alcohols; 3. transformation of intermediates to H₂, CO₂, and acetic acid (acetogenesis); 4. formation of methane (methanogenesis) from H₂ and CO₂ or acetate by highly specialized Archaea.
Salient Features of Five Anaerobic Digestion Variants*

<table>
<thead>
<tr>
<th>Feature</th>
<th>UASB</th>
<th>IBR</th>
<th>CSTR</th>
<th>Leach Bed</th>
<th>Tall Silo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three-phase separator at top of reactor</td>
<td>Passive</td>
<td>Active</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>Input</td>
<td>Aqueous influent with high particulate solids content</td>
<td>Flowable influent with moderate particulate solids content</td>
<td>Flowable influent with high particulate solids content</td>
<td>Solid phase Input</td>
<td>Solid phase Input</td>
</tr>
<tr>
<td>Recycle ratio (old/new)</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>High (2/1)</td>
<td>Very high (6–8/1)</td>
</tr>
<tr>
<td>Introduction and transit through reactor</td>
<td>Pumped in, passive upflow through biologically mature bed</td>
<td>Pumped in, passive upflow through biologically mature bed</td>
<td>Pumped in, vigorously mixed to keep solids in suspension</td>
<td>Wheeled loader</td>
<td>Batches lifted to top via cement pump, gravitational descent</td>
</tr>
<tr>
<td>Operational mode</td>
<td>Continuous</td>
<td>Continuous</td>
<td>Continuous</td>
<td>Batch</td>
<td>Contiguous, batches</td>
</tr>
<tr>
<td>SRT and HRT</td>
<td>SRT &gt; HRT</td>
<td>SRT &gt; HRT</td>
<td>SRT = HRT</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>Thermophilic processing</td>
<td>Feasible</td>
<td>Feasible</td>
<td>Not feasible</td>
<td>Not feasible</td>
<td>Feasible</td>
</tr>
<tr>
<td>Fosters development retention of methanogenic consortia</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Methane yield relative to potential post digestion composting</td>
<td>High</td>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Post digestion composting</td>
<td>Minor, operation if at all</td>
<td>Minor, operation if at all</td>
<td>Major, operation</td>
<td>Major, operation</td>
<td>Major, operation</td>
</tr>
</tbody>
</table>

*UASB is a named but not patented approach; IBR is a patented technology. The other types are generic approaches finding various applications. UASB, upflow anaerobic sludge bed (or blanket) digestion; IBR, induced bed (or blanket) reactor; CSTR, continuously stirred tank reactor; leach bed, high recycle ratio pile sprinkled with leachate; tall silo, vertical structure with successive very high recycle ratio batches.

Owing to this limitation, in treating solid wastes via UASB, the solids must first be converted to an aqueous wastewater stream. This conversion starts prior to biological treatment, with extensive mechanical disruption, size reduction, and successive screenings. Biological processing is in two stages: first an acidogenic stage performed in a continuously stirred tank reactor (CSTR), followed by a UASB methanogenic stage. Additional screening is needed between stages to remove recalcitrant particulates. While UASB is the gold standard in the wastewater domain, its application to solid wastes is extremely awkward.

Like UASB, induced bed reactor (IBR) is a rational technology informed by the science of microbial methanogenesis and the factors needed to achieve high rates. It, too, fosters development and retention of methanogenic consortia in the form of a suspended bed. IBR was initially developed for treating dairy manure flush water laden with as high as 10% particulate solids, without the necessity of their prior removal. That need is eliminated through more effective retention of culture by means of an active three-phase separator. Acidogenesis and methanogenesis are thus accomplished in a single reactor, with multiple reactors operated in parallel.

IBR is an example of a technology originally intended for a narrow application that has much wider utility. As applied to solid waste, while mechanical separation work prior to biological processing is not entirely eliminated, it is greatly reduced because IBR thrives on particulate-laden waste streams. IBR has the advantages of UASB without its intolerance of particulates.

Continuous stirring of anaerobically digesting liquor in sealed tanks is a historic transplant from aerobic sewage treatment, where vigorous mechanical agitation was used in open tanks to keep particulates in suspension and introduce oxygen into solution. Continuously stirred tank reactor (CSTR) was adapted to anaerobic digestion of primary settled sewage and secondary waste activated sludge before the profound difference between aerobic and anaerobic treatment was understood. But stirring disrupts consortia and is inconsistent with the disparate growth rates and environmental requirements of acidogens and water, forming a powerfully methanogenic suspended bed through which aqueous waste flows in its upward transit through the reactor. UASB was developed specifically for treating strong industrial wastewaters, such as those generated at breweries. Its limitation is that particulate solids in the waste stream tend to upset the system through poorly understood mechanisms.
methanogens within the anaerobic system. Nonetheless, CSTR anaerobic digestion remains a standard practice for U.S. municipal wastewater treatment facilities, and its fundamental deficiency of disrupting, rather than fostering, consortia is not considered in professional organization guidance documents and wastewater engineering textbooks. Richard Speece of the Vanderbilt University Department of Civil & Environmental Engineering, Nashville, Tenn., has reviewed recent research on this issue.

The leach bed approach is a transplant from aerobic composting. Fresh solid waste is heavily inoculated by mixing with previously processed material at high recycle ratios. Within a sealed vault, the new batch is irrigated with leachate amended with lime to counteract the decline in pH that would otherwise occur through acidogenesis getting ahead of methanogenesis. Gas is conveyed to storage. Material is moved in and out of the vault via wheeled loaders. A large component of a leach bed facility is after-the-fact aerobic composting, reflecting incomplete anaerobic digestion with much of the potential for methane production unexpressed.

The tall silo method involves very high recycle ratios. Successive batches are lifted to the top of a column to fill the void left as material exits from the bottom of the silo. The moisture content of the mixture must be high enough for it to slip through the silo. Gas is collected from a capped space at the top. At tall silo facilities, finishing through aerobic composting is a major operation.

In recent decades, great strides have been made in the basic science of microbial methanogenesis. Application of this progress to anaerobic digestion would advance the practice of solid waste management.

SUGGESTED READING


Hi Paul, Nik and Stephen,

Below, please find a comment on the Economic Feasibility report from Allen Dusault.

Jennifer

---

From: Allen Dusault [mailto:ADusault@suscon.org]
Sent: Monday, May 17, 2010 1:18 PM
To: Jennifer Tencati
Subject: RE: Revised Economic Feasibility Report

Jennifer,

Great effort. The document looks good. A couple of minor suggestions. On page 5 there are estimates of biogas/methane production and electricity generating potential from dairies looking at cows as a yardstick. These estimates seem very low. One of the digester company's we work with says the numbers are much lower than what they get. You do recognize the numbers as conservative but they may be overly so.

Also note that the units on the electricity generation is expressed in KW. You should include the time unit in hours (i.e. KWh)

One other minor correction. Bob Joblin is referenced as affiliated with Utilitech. He is with AgPower Partners.

Allen

---

From: Jennifer Tencati [j.tencati@circlepoint.com]
Sent: Saturday, May 15, 2010 8:17 AM


Appendix A-249
Dear TAG members,

Attached, please find a revised copy of the Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report. This updated report includes comments from the CPUC, utilities and others who participated in a review of the earlier draft report in San Francisco on April 26th. We appreciate everyone’s insights and efforts in the review process.

Please provide any final comments you may have on the report to me by Monday, May 24th. Comments can be submitted by email to j.tencati@circlepoint.com or by fax to (916) 658-0189.

If you have any questions about the report or the Dairy Digester project, please give me a call at (916) 658-0180 x131.

Kind regards,

Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

455 Capitol Mall, Suite 802
Sacramento, CA  95814-4427

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Hi All,

Below, please find comments on the revised Economic Feasibility Report from [Dave Warner, Director of Permit Services, San Joaquin Valley APCD].

-Jennifer

Hi Jennifer,

The following paragraph from page 9 of the economic feasibility paper is misleading in a couple of ways:

Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in the determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. This emission standard has been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards.

The 9-11 ppm standard applies only to new equipment, but most readers would assume that standard to somehow be responsible for producers shutting down existing digesters. Also, the comment about the six operating digesters being shutdown because of air district requirements is incorrect. First of all, the District is aware of 7 dairy digesters with engines in the SJV. Two of those are new units subject to, and are currently operating in compliance with, the new-unit limit of 9-11 ppm. That leaves five operations that were affected by the rule in question (Rule 4702, for controlling NOx from internal combustion engines). Of the seven total, here is our understanding of events:
Operational Dairy Digesters

**Castelanelli Brothers Dairy** – Replaced old engines with new lean burn engine with higher efficiency and less emissions. Complies with 4702.

**Cottonwood Dairy (Gallo)** – New rich burn engine with catalyst. Did not have problems meeting the Rule 4702 NOx limit but had difficulty meeting the 9 ppmv Best Available Control Technology (BACT) limit for new equipment. Now operating in compliance with the 9 ppm limit.

**Fiscalini Dairy** – New lean burn engine with Selective Catalytic Reduction. Engine currently operating and SCR system has recently been achieving less than 11 ppmv NOx to comply with BACT. The new engine did not have problems meeting 4702 NOx limits but was subject to the BACT limit for NOx. (Note: 11 ppm from a lean burn engine is equivalent to 9 ppm from a rich burn engine.)

**Hilarides Dairy** – Grandfathered engines were modified to operate in lean burn mode to comply with 150 ppmv NOX emission limits in Rule 4702. Engines were never shut down but allowed to operate under a variance until modifications to the engine were complete.

Non-Operational Dairy Digesters

**Eden Vale Dairy** – Previously operating but ceased operation and submitted application to make unit dormant. It is unclear if digester ceased operation before or after Rule 4702 requirements came into effect. Based on information from CEC PIER Dairy Digester System Program Evaluation Report, Page, Table 20, NOX emissions from the engine were measured to be 129 ppmv @ 14.1% O2 equivalent to 112 ppmv @ 15% O2. Therefore, the engine already complied with Rule 4702 because the engine had greater than 4% O2 in the exhaust and would be classified as a lean burn engine subject to the 150 ppmv NOX limit.

The reason the engine was shut down were economic and are discussed in pages 44-47 of the CEC report. Basically, it was not economic to run the engine at full capacity because net metering does not allow full recovery of the costs to run the engine.

**Koetsier Dairy** – Ceased operation prior to Rule 4702 requirements taking effect. Plug Flow digester needed to be cleaned out and heated up with external heat source prior to being used again. Applicant submitted application to make unit dormant. Based on information from CEC PIER Dairy Digester System Program Evaluation Report, Page, Table 20, NOX emissions from the engine were measured to be 86 ppmv @ 8.9% O2 equivalent to 42.5 ppmv @ 15% O2. Therefore, the engine already complied with Rule 4702 NOX limits of 90 or 150 ppmv.
Economics and net metering appear to be the main reason the system is not currently operating.

**Lourenco Dairy** – Engine had not operated for a number of years prior to Rule 4702 and was not operational during CEC study period. The dairy is currently being leased out to Mr. Fagundes and he has no plans to operate the digester.

**General Conclusion**

The District assisted applicants to try to comply with the 4702 emissions standards and worked with anyone who wanted to continue to operate digester gas engines. The two dairy digesters that ceased operation did so mainly because of economics or other issues because they already complied with the Rule 4702 emissions limits. Complying with rule 4702 emissions limits is not difficult.

As you can see, the rumour that was reported as fact in the TAG meeting is tough to reconcile with the actual facts. It’s a stretch to say that air requirements were even “partly” responsible for the shutdowns, but it is clearly not accurate to leave the other reasons unstated.

I would suggest that we not make use of unsubstantiated and unattributed statements in a document that may be a basis for important digester-related decisions well into the future, or if we do use them, provide a robust exploration of their claims. I would also suggest that this paragraph be re-written, perhaps as follows:

Nonetheless, the air quality emissions of operating these electrical generation technologies are a critical factor in determining the feasibility of biogas/biomethane use for electrical generation within the Central Valley. The most recent San Joaquin Valley Air Pollution Control District requirements for new digesters with electrical power production limit NOx emissions to 9 - 11 ppm. Another air district rule (Rule 4702) limits NOx emissions of existing lean burn engines fired on dairy digester gas to 150 ppm, and existing rich burn engines to 90 ppm. Although these emission limits are less strict than those that non-farm engines must meet (75 and 50 ppm, respectively), they have been reported to be very challenging for dairy digester operators that want to generate electricity from the biogas. It was mentioned in the March 24, 2010 TAG meeting that six of the operating digesters ceased operations at least partly due to their inability to produce electricity in compliance with air emission standards. However, the air district refutes this claim, and states that the Rule 4702 limits for digester engines are not difficult to achieve. According to the air district, there were seven total digester-engine systems in the valley, and only five existing digester systems were affected by the rule. Only two or three were actually operating at the time the rule went into affect. Two of these systems continue to operate. Two of the remaining three had previously shown compliance with the district’s rule, so there were no costs associated with meeting the requirements of the rule. At least two of the three currently non-operational engines had ceased operation well prior to the rule taking affect. Therefore, the Air District concludes that their Rule 4702 had virtually no impact on the status of operational digesters in the San Joaquin Valley.

In addition, the next paragraph on the same page contains the following sentence:

Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 - 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the Ingersoll-Rand MicroTurbine can generate 250 kW of power at less
The word “infeasible” is not correct to use here. Operating a dairy digester engine at 9-11 ppm is certainly feasible. We agree that microturbines have the ability to meet these emissions limits, and in addition two digester operators in the San Joaquin Valley are proving that these limits can be met with reciprocating engines, as well: Gallo’s Cottonwood facility is operating in compliance with this limit using a three-way catalyst on a rich burn engine, and Fiscalini’s facility is operating in compliance using a lean-burn engine with selective catalytic reduction. Neither operator would tell you that it has been cheap to do so, or easy, but "infeasible" is simply not correct.

Finally, the air district believes that all potential digester operators could invest in technology that would allow digesters to operate in compliance with the district’s emissions limits that are discussed above, but the additional difficulty and cost will require widespread support for the larger point made in the feasibility report – these systems are generally not viable without financial support and incentives.

My suggestion for a rewrite of this section:

Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9-11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the Ingersoll-Rand Microturbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010). In addition, the San Joaquin Valley Air District strongly disagrees that achieving 9-11 ppm is infeasible for new operations. They report that the two newest San Joaquin Valley dairy digester power-production operations are currently operating in compliance with this standard, and applications have been filed for a number of additional operations that intend to meet this standard. A third operational digester feeds biomethane into the natural gas pipeline, which is an even lower-polluting option to get bioenergy out of a digester. The District contends that while operations that can achieve this standard are more expensive to construct and operate than their more polluting counterparts, they are a necessary part of controlling air pollution in the San Joaquin Valley, one of the most polluted air basins in the country.

Thanks for providing another chance to review this document, and please feel free to pass this information along to anyone and everyone – I’d be appreciative of any input we can receive, especially if our understanding is not correct.

Dave Warner
Director of Permit Services
San Joaquin Valley APCD
Dear TAG members,

Attached, please find a revised copy of the Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report. This updated report includes comments from the CPUC, utilities and others who participated in a review of the earlier draft report in San Francisco on April 26th. We appreciate everyone’s insights and efforts in the review process.

Please provide any final comments you may have on the report to me by Monday, May 24th. Comments can be submitted by email to j.tencati@circlepoint.com or by fax to (916) 658-0189.

If you have any questions about the report or the Dairy Digester project, please give me a call at (916) 658-0180 x131.

Kind regards,

Jennifer

Jennifer Tencati
Project Manager

j.tencati@circlepoint.com

916.658.0180 x131
From: Kevin Maas [kevin@farmpower.com]
Sent: Sunday, May 23, 2010 9:35 PM
To: Jennifer Tencati; jtencati@hotmail.com
Cc: Paul Miller; Stephen Klein
Subject: Re: Dairy TAG meeting cancelled

Hello TAG staff--

I have one comment on the economic feasibility draft: the page 6 section on types of manure digesters doesn’t look outside California, where the majority of manure digesters being installed are a hybrid mixed/plug-flow system that has a successful record of co-digestion. The report should consider the experience of other states with numerous digesters, such as Wisconsin.

Thanks,

Kevin

Farm Power
http://www.farmpower.blogspot.com
360.424.4519 (office)
360.770.9212 (mobile)

---

From: Jennifer Tencati <jtencati@circlepoint.com>
Date: Thu, 20 May 2010 16:50:16 -0700
To: "jtencati@hotmail.com" <jtencati@hotmail.com>
Cc: 'Paul Miller' <PMiller@esassoc.com>, 'Stephen Klein' <sklein@waterboards.ca.gov>
Subject: Dairy TAG meeting cancelled

Dear TAG members,

The fourth TAG meeting has been cancelled until further notice. There will not be a TAG meeting on Wednesday, May 26, 2010.

We have decided that the EIR preparation team needs to stay focused on preparing the Draft EIR. The Draft EIR is still on schedule for release at the end of June.

The TAG has provided a great benefit to the staff preparing the Draft EIR with the interactions that have already occurred in the meetings and the review of the various reports. We have received excellent comments over the past few weeks on several of the draft reports that we sent to the TAG for review. We truly appreciate everyone’s efforts.

The TAG has been asked to submit comments on the “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities” Draft Report by May 24th. We have already received several good comments on the report and still would appreciate your comments.

8/20/2010
input on that draft report.

We will be releasing some additional reports to the TAG, but the schedule for those is uncertain. Releasing additional reports will be a secondary effort, but a couple of the remaining reports are almost ready for distribution to the TAG and should be distributed to the TAG in time to get some additional feedback from the TAG that will benefit the EIR.

If you have any questions please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x 131.

Kind regards,
Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

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Please think of the environment before you print this email
Hi All,

Below, please find a comment on the Economic Feasibility report from Daniel Mann.

-Jennifer

From: Daniel Mann [mailto:daniel.mann@mt-energie.com]
Sent: Monday, May 24, 2010 10:59 AM
To: Jennifer Tencati
Subject: Comment on the "Key Factors Determining Economic Feasibility..."

Jennifer,

Our complete mix systems are able to handle manure with a TS content of up to 12.5% without adding water to the process.

Best regards

Dipl. Wi-Ing. Daniel Mann

MT-Energie USA Inc.

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4900 California Ave.,
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Bakersfield, CA 93309
USA

www.mt-energie.com
Dear TAG members,

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If you have any questions please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x 131.

Kind regards,

Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x 131

CirclePoint
455 Capitol Mall, Suite 802
Hi Nik,

Below are comments from Neil Black, California Bioenergy.

-Jennifer

---

From: Neil Black [mailto:nblack@calbioenergy.com]
Sent: Monday, May 24, 2010 1:20 PM
To: Jennifer Tencati
Cc: Paul Miller; Stephen Klein; Ross Buckenham; Jackson Lehr
Subject: Re: Revised Economic Feasibility Report

Jennifer:

Our suggested changes are in blue below. Please let me know if you have any questions.

Best regards,

Neil

Neil Black
President | California Bioenergy LLC | http://www.calbioenergy.com
nblack@calbioenergy.com | (office) 646-896-3989 | (cell) 917-589-6009

Executive Summary

Role of Utilities... Significantly streamlined (and/or if possible utility cost shared) interconnection procedures for [delete “for”] would improve the economic feasibility of digester-based gas and electricity projects

Access to Capital and Third Party Developers. The current financial difficulties facing most dairy farmers and the generally tight credit market will ensure that funding for digester developments will be scarce and costly for the foreseeable future. While increased participation by third party developers may provide some technical and financial assistance, private capital will be relatively costly. The potential "capital crunch" constraints will be especially acute for those projects that require major construction, involve new technical applications and/or supply energy to less established and developing non-utility markets. With sufficient prices and contracting mechanisms, third-party developers could play a key role in widespread digester deployment, creating standardized development processes and ongoing operations, enabling capital efficiency and cost reductions ([potentially significant over time]), and making it easier for dairies to host digester electricity and biomethane projects.

*Air Quality Regulation of On-site Electrical Generation. On-site generation of electricity represents a potential direct, “lower tech” and inexpensive beneficial use option for biogas. Recent air quality restrictions within the Central Valley may preclude this use. However, if cost effective compliance technologies or mitigation can be developed [, and some promising technologies will be brought on line and tested in the near future], digester systems could be greatly enhanced – especially if feed-in tariff revenues increase the revenue potential sufficiently for
small scale distributed energy production to be developed.*

Also see below

"Cost and Minimum Size for Biogas Upgrading. Biogas scrubbing and conditioning for [pipeline quality] biomethane production is currently costly and can only be cost effectively performed at production levels significantly greater than most individual dairy operations can support. Combined with biogas upgrade system costs, system design and location requirements [also] represent key factors limiting the feasibility for widespread development of [pipeline quality] biomethane facilities for the foreseeable future."

"Technological Change. Although many of the core digester and biomethane technologies are fairly well established, future commercialization of dairy manure digester systems may be expected to result in some cost effectiveness improvements. However, currently most foreseeable improvements appear to be incremental rather than fundamental. Consequently, most analysts suggest that per unit production costs for biomethane and related electrical generation will remain higher than commodity energy prices and hence public support for production will remain necessary [though over time at lower levels]. Key technology breakthroughs that could dramatically [remove “dramatically”] improve future dairy digester profitability include cost-effective on-site electrical generation with biogas [e.g., very low emission internal combustion engines, micro-turbines or fuel cells] or inexpensive, efficient and/or farm sized biogas upgrading systems with low-pressure distribution line injection."

*This would also require a change in the body of the document: Electrical Generation (page 10)

"Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, currently properly operated “clean burn” IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations (Joblin, 2010). While additional selective catalytic reduction can in some cases be used to further reduce emissions, the necessary secondary emission controls are expensive and difficult to operate on lower energy fuels such as unrefined biogas. Several of the industry analysts interviewed stated that from their experience commercial on-site electrical generation with biogas conforming with 9 – 11 ppm is infeasible with the current available technology (Dusault, 2010; Joblin, 2010) although others state that existing systems such as the Ingersoll-Rand MicroTurbine can generate 250 kW of power at less than 6 ppm (Tiangco, 2006; TAG member comment, March 24, 2010). In addition other new IC technologies will be brought on line and tested in the near future."

On 5/15/10 11:16 AM, "Jennifer Tencati" <j.tencati@circlepoint.com> wrote:

Dear TAG members,

Attached, please find a revised copy of the Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report. This updated report includes comments from the CPUC, utilities and others who participated in a review of the earlier draft report in San Francisco on April 26th. We appreciate everyone’s insights and efforts in the review process.

Please provide any final comments you may have on the report to me by Monday, May 24th. Comments can be submitted by email to j.tencati@circlepoint.com or by fax to (916) 658-0189.

If you have any questions about the report or the Dairy Digester project, please give me a call at (916) 658-0180 x131.

Kind regards,
Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com <mailto:j.tencati@circlepoint.com>
916.658.0180 x131


Appendix A-265
Hi All,

Attached, please find comments on the Economic Feasibility report from the Inland Empire Utilities Agency.

-Jennifer

From: Dan Geis [mailto:dgeis@dolphingroup.org]
Sent: Monday, May 24, 2010 4:32 PM
To: Jennifer Tencati
Subject: Comments on the draft Economic Feasibility Report

Jennifer:

Please find attached the comments of the Inland Empire Utilities Agency (IEUA) on the draft document "Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities."

Please contact me if you have any questions.

Dan Geis
The Dolphin Group
916.441.4383

https://exchange.csassoc.com/exchange/PMiller/Inbox/FW:%20Comments%20on%20the...
May 24, 2010

Stephen James Klein, P.E., M.S.
Water Resources Control Engineer
Regional Water Quality Control Board, SF
1685 E Street
Fresno, CA 93706

Re: Comments on ESA April 2010 Administrative Draft/Draft Reports

On behalf of the Inland Empire Utilities Agency (IEUA), I wanted to take the opportunity to clarify some information regarding our facility contained in the draft report: “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities.” Thank you for the opportunity to submit these brief comments.

IEUA would like to clarify the following points contained in the draft report:

• The IEUA project is no longer operating using dairy manure, and this is largely due to the impact of Rule 1110.2. The new feed stock will be food waste, not dairy manure;
• The project has been expanded from a plug-flow to a European-style digester capable of producing 3 MW of power;
• On page 8, the report references $2 million in funding from the CEC. The total amount of funding from the CEC was approximately $7 million in two phases;
• It should be clarified that the IEUA facilities were constructed to eventually convert from dairy manure to biosolids, so the capital investment is intended for infrastructure that is intended to be operational over 50-years or more. This should be clarified on page 31; and
• The report should consider that regional biogas facilities may utilize a variety of feedstocks, not just dairy manure, for the benefit of the Central Valley.

Thank you for the opportunity to provide this clarification. If you have any further questions, please do not hesitate to contact me.

Sincerely,

[Signature]

Martha Davis
Executive Manager for Policy

Fifty-Five Years of Excellence in Water Resources & Quality Management

Terry Callin
President
Angel Santiago
Vice President
Michael E. Camacho
Secretary/Treasurer
Gene Koopman
Director
John L. Anderson
Director
Richard W. Alwiler
Chief Executive Officer
General Manager

Appendix A-268
Hi All,

Attached, please find comments on the Economic Feasibility report from Jeff Cox, Fuel Cell Energy.

-Jennifer

Dear Jennifer,

Please find attached the comments of Jeff Cox from Fuel Cell Energy (FCE) on the draft document "Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities."

Please contact me if you have any questions.

Dan Geis
The Dolphin Group
916.441.4383
May 24, 2010

Stephen James Klein, P.E., M.S.
Water Resources Control Engineer
Regional Water Quality Control Board, 5F
1685 E Street
Fresno, CA 93706

Re: Comments on ESA April 2010 Administrative Draft/Draft Reports

On behalf of Fuel Cell Energy (FCE), I appreciate the opportunity to comment on the draft report: “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities.” While we have not yet participated in your process to date, we hope that the information contained herein will assist the Regional Board in accurately reflecting the status of the fuel cell technology and its potential applications within the dairy biogas industry.

Revenue Factors – Overall System-wide Estimates

- Further details and data should be provided to reinforce the accuracy of the stated conversion of methane to electricity. While this analysis is intended to create a better understanding of how much electricity can be generated from each cow’s methane production, it fails to offer a meaningful comparison of conversion efficiencies from all available power generation technologies. For example, the estimate of 36 cubic feet of methane yielding 0.107 kW[h] of electricity represents an extremely low conversion efficiency and, consequently, negatively influences the broader evaluation of economic feasibility for dairy manure digesters. Low power production estimates such as this could lead to an inaccurate assumption that dairy digesters are incapable to producing significant amounts of electricity and, therefore, are not economically viable.
- Table 1 of the report summarizes various power generation technologies. It would be helpful to incorporate the per cow methane production data into this table in an effort to demonstrate the effects of conversion efficiency in relation to comparably sized generation systems. For example, the table provides some data about fuel cells but fails to accurately depict how their higher conversion efficiency would influence the prior section’s electrical power yield on a per cow
basis. Using the same estimate of 36 cubic feet of methane, a fuel cell (similar to the 900 kW system currently operated by the City of Tulare at its wastewater treatment plant) would produce a total of 4.641 kWh. If expressed on a per hour basis similar to the example presented in the draft report, the fuel cell would deliver 0.193 kW in comparison to the stated value of 0.107 kW, or roughly 80% more power from the same volume of methane. Ultimately, an accurate description of the true power generation potential of dairy digester methane will better inform the evaluation of the digesters themselves.

Among the various bits of data summarized in Table 1, the most influential component affecting the economic feasibility of a dairy digester system is the cost of the generator. Although the draft cites its sources for this data, published figures from several hundred operational projects participating in California’s Self-Generation Incentive Program (“SGIP”) offer a differing view of these same system costs. In its capacity as one of the local administrators of the SGIP, PG&E publishes a table (most recently updated on April 10, 2010) of system costs for all past project participants where actual installed costs for IC engines, microturbines, gas turbines, and fuel cells operated on biogas can be reviewed. The following table compares the figures from Table 1 with actual costs published by PG&E via its SGIP web page.

Table 1 – Comparison of Electrical Generation Technologies for Biomethane

<table>
<thead>
<tr>
<th>Generation Technology</th>
<th>Average Installed System Size (kW)</th>
<th>Draft Table 1 Cost Estimate ($/kW)</th>
<th>PG&amp;E’s SGIP Actual Cost ($/kW)</th>
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<tbody>
<tr>
<td>Microturbines</td>
<td>179</td>
<td>$300 - $1,000</td>
<td>$4,410</td>
</tr>
<tr>
<td>Gas Turbines</td>
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</tr>
<tr>
<td>IC Engines</td>
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<td>$300 - $900</td>
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<tr>
<td>Fuel Cells</td>
<td>404</td>
<td>$5,500 - $12,000</td>
<td>$6,780</td>
</tr>
</tbody>
</table>

In addition to the cost estimates that do not compare favorably with PG&E’s published data from actual field installations, Table 1 further suggests that only phosphoric acid fuel cells are available and their costs are many times greater than comparably sized combustion based technologies. As further evidenced by PG&E’s published SGIP data, this cost comparison is not accurate and fails to account for the greater state-sponsored incentives and federal tax credits that are available to fuel cells to bring their net costs well below those of any competing technology. Moreover, the current roster of fuel cell projects in PG&E’s statewide summary indicates that only four systems representing 1400
kW, or roughly 3.7% of the total 37,000 kW of participating fuel cell systems are of the older phosphoric acid type. When operated on biogas, fuel cells of the molten carbonate type have been shown to be widely available, more efficient, and less costly than depicted in the draft report. As evidence of this status, it should be noted that the 900 kW molten carbonate fuel cell system operated the City of Tulare is shown in PG&E’s published data at a total installed cost of $5,760 per kW. This cost includes the requisite digester gas cleanup hardware that may not be reflected in the system prices of other technologies.

- Following Table 1, the draft further suggests that conversion efficiencies for biogas to electricity are limited to very low rates of 18 to 28.5%. Once again, this estimate relies exclusively on the usage of combustion technologies (specifically, internal combustion engines cited in the example) for the conversion of biogas to electricity. The usage of fuel cells significantly elevates the net electrical efficiency to 47% or greater and maximizes the potential electrical energy available from small sources of biogas. Moreover, the fuel cell achieves the higher conversion efficiency while producing negligible emissions that are well below the most stringent limits established by the presiding air districts. For reference, the draft comments on the extremely low limits for NOx emissions at 9 ppm and suggests that attaining this level for an IC engine is prohibitive. It should be noted that fuel cells operated on biogas and tested by the South Coast AQMD were shown to produce NOx emissions of less than 0.01 ppm in normal operating conditions.

**Government Grants and Assistance**

- The draft inaccurately states that the California SGIP program limits its incentives for fuel cells to no more than 50% of the total project cost. While this project cost limit is in effect for several other ratepayer funded initiatives, the SGIP does not impose this 50% cost limit on eligible fuel cell projects.
- The draft neglects to include the additional incentives available for fuel cells via the federal investment tax credit. The current program offers a tax credit of up to $3,000 per kW or a maximum of 30% of the total project cost.

**Cost Factors – On-site Electrical Generation**

- The Draft Report relies on the rather low conversion efficiency of biogas to methane in developing its estimate of the annual dollar value of electricity available as a surplus that could be sold to the utility. Substituting the higher conversion efficiency of a fuel cell for the less efficient IC engine, the same $39 of surplus electricity cited in the draft report would grow to a surplus value of $137.27 after deducting the cow’s own $66 of parasitic electrical demand. This higher revenue estimate should be noted as it is influential in the evaluation of the dairy digester’s overall economic feasibility.
- The draft report states …"given the current air quality restrictions, on-farm electrical production with biogas is generally considered to be economically
infeasible in the Central Valley...". It should be noted that this conclusion was developed as a result of the reliance on very inefficient and dirty generation technologies. The ability to secure an operating permit from the local air district is, indeed, restrictive for traditional combustion technologies and may create a need to pay additional fees for NOx emissions. The City of Tulare faced these same considerations when it selected its 900 kW fuel cell system instead of a competing IC engine. The ongoing permitting fees and NOx credits associated with the IC engine would have represented combined fees and penalties of $600,000 per year whereas the fuel cell was exempt from air permits and created no need for additional NOx credits. Thus, the usage of fuel cells with their higher conversion efficiency and ability to overcome emissions limits can function as an effective means supporting the economic feasibility of on-farm electrical production.

Thank you very much for the opportunity to supply these comments. Please feel free to contact me if you have any questions, and I look forward to being further involved in this important process.

Jeff Cox
FuelCell Energy
Office (760) 741-3970
Hi All,

Attached, please find comments on the Economic Feasibility report from the Agricultural Energy Consumers Association.

-Jennifer

---

Jennifer:

Please find attached the comments of the Agricultural Energy Consumers Association on the draft document “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities.”

Please contact me if you have any questions.

Dan Geis

The Dolphin Group

916.441.4383
May 24, 2010

Stephen James Klein, P.E., M.S.
Water Resources Control Engineer
Regional Water Quality Control Board, 5F
1685 E Street
Fresno, CA 93706

Re: Comments on ESA April 2010 Administrative Draft/Draft Reports

Dear Stephen:

In reviewing the May 2010 draft of the document entitled “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities,” there were a few areas related to the feed-in-tariff (FiT) that I believe merit further discussion and comment.

As noted on pages 1-2 and in footnote 1, FiTs are essential to promoting the economic feasibility of these projects. For small-to-medium sized renewable energy installations, such as biogas digesters, it is imperative that an appropriate renewable energy price be established to promote these projects with a minimum of administrative hurdles to overcome. Unfortunately, despite the fact that SB 32 (Negrete-McLeod) became law on January 1, 2010, the California Public Utilities Commission has yet to implement this measure and adjust these prices accordingly.

Implementation of this bill by the CPUC is the most important action that can be taken to promote the commercialization of dairy biogas digesters in California.

Although feed-in tariffs currently exist, and offer very few administrative burdens for projects, they are set at a price point that is insufficient to commercialize the market. AB 1969 (Yee—2006) initially created these feed-in tariffs, and set the price equal to the market price referent (MPR), which is determined annually by the CPUC, and based primarily on natural gas prices.

In 2009, the MPR price offered by the FiT was 11.13 cents/kWh for a 20-year contract. Due to falling natural gas prices in that year, the CPUC reduced the MPR to only 9.67 cents/kWh in 2010, a decline of over 10%. Basing the price paid for small renewable projects primarily on the cost of fossil fuel is unsustainable. Currently, the only “green” attribute that calculated into the MPR is greenhouse gas emissions. SB 32 requires the Commission to consider all
environmental benefits in calculating the price paid under these FiTs to accurately reflect the renewable nature of the energy delivered to ratepayers.

Recent analysis from the solar industry estimates that the MPR undervalues renewable energy prices by 6-10 cents/kWh, depending on their location and technology. Both PG&E and Southern California Edison have been recently authorized to purchase select solar generation facilities in this size range at an approximate price of nearly 20 cent/kWh, twice what biogas digesters qualify for under the FiT. It is clearly evident that the current price and methodology employed by the CPUC under AB 1969 is inadequate to sustain the development of a commercial dairy biogas industry. This underscores the importance of SB 32 and the need for its rapid implementation.

Because the renewable industry is aware of the recent drop in prices, and also aware of the improvement to the economics of these projects that SB 32 will create, the result has been a near total stagnation of investment in all renewable projects of this size, including dairy biogas projects. Why sign a long-term contract to today’s low prices, with the prospect for great improvement under SB 32 just around the corner?

The single greatest remaining obstacle to the commercialization of a vibrant dairy biogas market is the establishment of an appropriate renewable market price for electricity that affords a predictable income stream to make the project feasible. Until a sustainable market price for biogas-to-electricity is established, the widespread deployment of dairy biogas facilities will not take place in California.

Thank you for the opportunity to submit these comments. If you have any questions, please do not hesitate to contact me.

Sincerely,

Michael Boccadoro
Executive Director
Hi Paul, 

Below is Daniel Mann’s 5/28 comment on the economic feasibility report.

-Jennifer

From: Daniel Mann [mailto:daniel.mann@mt-energie.com]
Sent: Friday, May 28, 2010 1:16 PM
To: Jennifer Tencati
Subject: RE: Comment on the “Key Factors Determining Economic Feasibility...”

Jennifer,

It is probably late now but I did not have time before to finish reading it. The upgrading system our subsidiary MT-Biomethan produces has significantly smaller methane losses than those mentioned in the Draft. Our systems methane slippage is below 0.1% a very unique feature of our systems.

Best regards
Dipl. Wi-Ing. Daniel Mann
MT-Energie GmbH & Co. KG

MT-Energie USA Inc.
new address!
4900 California Ave.,
Tower B-210
Bakersfield, CA 93309
USA

www.mt-energie.com
Fon: +1 661-377-1875
Fax: +1 661-377-1848
E-Mail: info@mt-energie.com

From: Jennifer Tencati [mailto:j.tencati@circlepoint.com]
Sent: Monday, May 24, 2010 11:09 AM
To: ‘Daniel Mann’
Subject: RE: Comment on the “Key Factors Determining Economic Feasibility...”

8/20/2010

Appendix A-277
Thank you for your comment Daniel. I have passed this on to the appropriate team members.
-Jennifer

From: Daniel Mann [mailto:daniel.mann@mt-energie.com]
Sent: Monday, May 24, 2010 10:59 AM
To: Jennifer Tencati
Subject: Comment on the "Key Factors Determining Economic Feasibility..."

Jennifer,

Our complete mix systems are able to handle manure with a TS content of up to 12.5% without adding water to the process.

Best regards
Dipl. Wi-Ing. Daniel Mann
MT-Energie GmbH & Co. KG
E-Mail: daniel.mann@mt-energie.com

---

MT-Energie USA Inc.
new address!
4900 California Ave.,
Tower B-210
Bakersfield, CA 93309
USA
www.mt-energie.com
Fon: +1 661-377-1875
Fax: +1 661-377-1848
E-Mail: info@mt-energie.com

Dear TAG members,

The fourth TAG meeting has been cancelled until further notice. There will not be a TAG meeting on Wednesday, May 26, 2010.

We have decided that the EIR preparation team needs to stay focused on preparing the Draft EIR. The Draft EIR is still on schedule for release at the end of June.

8/20/2010
The TAG has provided a great benefit to the staff preparing the Draft EIR with the interactions that have already occurred in the meetings and the review of the various reports. We have received excellent comments over the past few weeks on several of the draft reports that we sent to the TAG for review. We truly appreciate everyone’s efforts.

The TAG has been asked to submit comments on the “Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities” Draft Report by May 24th. We have already received several good comments on the report and still would appreciate your input on that draft report.

We will be releasing some additional reports to the TAG, but the schedule for those is uncertain. Releasing additional reports will be a secondary effort, but a couple of the remaining reports are almost ready for distribution to the TAG and should be distributed to the TAG in time to get some additional feedback from the TAG that will benefit the EIR.

If you have any questions please contact me at either j.tencati@circlepoint.com or (916) 658-0180 x 131.

Kind regards,
Jennifer

Jennifer Tencati
Project Manager
jtencati@circlepoint.com
916.658.0180 x 131
Hi All,

Attached are comments on the Economic Feasibility report from PG&E.

-Jennifer

Jennifer:

PG&E's comments are in the attached file.

Ken Brennan
PG&E Product Management, Senior Project Manager | Office 415-973-0017; Cell 415-531-4173; Fax 415-973-6112 | Email: kjbh@pge.com
| Address: 245 Market Street, MC N15A, San Francisco, CA 94105

Dear TAG members,
Attached, please find a revised copy of the Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities report. This updated report includes comments from the CPUC, utilities and others who participated in a review of the earlier draft report in San Francisco on April 26th. We appreciate everyone’s insights and efforts in the review process.

Please provide any final comments you may have on the report to me by Monday, May 24th. Comments can be submitted by email to j.tencati@circlepoint.com or by fax to (916) 658-0189.

If you have any questions about the report or the Dairy Digester project, please give me a call at (916) 658-0180 x131.

Kind regards,

Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

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https://exchange.csassoc.com/exchange/PMiller/Inbox/FW:%20Revised%20Economic%2... 7/24/2010

Appendix A-281
Key Factors Determining Economic Feasibility of Dairy Manure Digester and Co-Digester Facilities

Page 1: Conventional Energy Prices

Issue: Strike “due to recent discoveries of new domestic shale gas reserves”.
Discussion: There are many other reasons why the price of natural gas may remain flat, such as additional pipeline and storage infrastructure.

Issue: Strike: “While future California electrical price may increase at a greater rate than inflation, the price increase will be primarily driven by the California Renewables Portfolio Standards (RPS) requirements.” This text also appears on page 15.
Discussion: There are many other reasons why the price of electricity may increase, such as infrastructure costs.

Page 2: Role of Utilities

Issue: Strike: “Significantly streamlined (and/or if possible utility cost shared) interconnection procedures for would improve the economic feasibility of digester-based gas and electricity projects.” See also page 38.
Discussion: This sentence is inaccurate. Interconnection procedures are well-defined in utility tariffs, and are based on experience and standard industry practice. Projects must be considered and assessed individually, as all projects will impact utility systems differently depending on the location of the project. The cost of each interconnection is determined based on the particular scenario of each project.

Page 14: Feed-In Tariffs

Issue: Strike: “PG&E and other California utilities” and replace with “California utilities”. Footnote 17 should therefore be deleted. All such references should be deleted through this document as well: pages 15,
Discussion: Legislation and regulation on statewide issues are not specific to any utility and PG&E would prefer to see the text not be specific to PG&E.

Page 19: Greenhouse Gas Emission Reduction Credits

Issue: Change the section header to read "Environmental Credits."
Discussion: RECs are not "Greenhouse Gas Emission Reduction Credits." This has caused much confusion, and distinguishing the two is critically important.

Issue: Strike "the project would not have happened without its financial investment"
Discussion: This is assuming financial additionality which has not been required by CAR or the ARB.
Issue: The description of CCAR is incorrect. CCAR does not have approved protocols for verifying carbon offset projects. There are no CCAR projects that have generated any carbon offsets.

Discussion: The Climate Action Reserve has the protocols and the projects. Change CCAR to CAR, and change the footnote to read "The Climate Action Reserve was formerly a program of the California Climate Action Registry. In April 2009, the California Climate Action Registry reorganized itself and now all carbon offset projects are overseen by the Climate Action Reserve."

**Page 20: Greenhouse Gas Emission Reduction Credits (cont.)**

Issue: In paragraph 1, change "(Brennan, 2010)" to "(PG&E, 2010)."
Discussion: This discussion comes from numerous departments in PG&E, not just from Brennan.

Issue: In paragraph 2, change "CCAR" to "CAR".
Discussion: Discussed above.

**Page 25: Manure Collection**

Issue: Strike: “Manure from the individual farms could either be piped to the centralized digester through a sewer system…”
Discussion: This will never happen due to cost ineffectiveness. The more likely scenario will be that each farm will have its own digester and transport raw biogas though low pressure PVC pipe to a centralized scrubbing facility.

**Page 38-39: Utility Cooperation**

Issue: Strike: “Several experts suggested that the market for future biogas conversion to biomethane would be improved if utilities such as PG&E were willing to invest, operate and maintain the necessary upgrading facilities required for pipeline injection.”
Discussion: In my comments on the first draft, I indicated that this sentence should be deleted. I now insist that you remove it from the document. This entire section must either be deleted or revised such that PG&E is not specifically mentioned.

**Page 38-39: Utility Cooperation**

Issue: Strike: “Under the current market and regulatory conditions, there is little incentive for PG&E or other utilities to assume the additional costs, risks and responsibilities. Furthermore, regulatory changes and CPUC approval would be necessary for PG&E to undertake any such biogas development projects and pass on the costs to ratepayers” or make generic to all California utilities.
Discussion: PG&E cannot be specifically singled out in your text. Either strike the paragraph its entirety or remove the specificity.
General Comments

- **Comment 1:** While this iteration is better, there is no substantial, deep-dive discussion on the issues which prevent the industry from growing, perhaps with the exception of air-permitting.
- **Comment 2:** The report is biased towards on-site generation with no substantial discussion around the efficiency of small generators. On-site generation is inherently inefficient, and can only be justified if the cost of interconnection (to a utility-scale plant) surpasses the cost of on-site generation (as a result of small, inefficient combustion).
- **Comment 3:** The discussion around biogas purchase-and-sale is very basic.
- **Comment 4:** There is no discussion or lesson learned in the technology section. It is presented in very simplistic cost/efficiency tradeoff with no discussion around performance.
- **Comment 5:** It would seem that Fuel-Cells and related state incentives have reinvigorated the industry yet there is little or no discussion of this subject.
- **Comment 6:** From an appearance standpoint, there are still quite a few typos, redundant spaces, different fonts, and missing words throughout the document. Those might question its professional standing.
Jennifer,

Thanks for this info. I have two questions with possibly follow up comments.

1. What is the purpose of this model? You say it will be “used to evaluate the economic feasibility of... digesters” but to what end and for whom? Does the economic feasibility of a digester project have any bearing on how it will be regulated under the programmatic EIR? Or is this a separate feasibility study the state is undertaking for informational purposes only?

2. More to the point, does the model appreciate any differences in digester designs and feedstocks? You have laid out various digester concepts in the “proposed systems” section, but not specified whether the digesters themselves are covered lagoons, mixed tanks, etc. or what the digesters are fed. This makes all the difference. If you run an economic model for, say a mixed plug flow co-digester with free-stall scrape manure using the “per cow” biogas production numbers from a covered lagoon running on post-separator open lot flush manure, you could be off on biogas production by a full order of magnitude. I guess what I’m saying is the current variables are not nearly complex enough to capture site-specific biogas production and hence economic feasibility, which is why I’m curious as to the model’s ultimate purpose.

Daryl Maas
Pixley Biogas
210-527-7631

From: Jennifer Tencati [mailto:j.tencati@circlepoint.com]
Sent: Thursday, August 12, 2010 4:39 PM
To: Jennifer Tencati
Cc: PMiller@esassoc.com; 'Stephen Klein'
Subject: Dairy Draft Economic Feasibility Report

Dear TAG Members:

The Draft Economic Feasibility Model Approach for Dairy Manure Digester and Co-digester Facilities report is attached to this email.

This report identifies the economic model approach that will be used to evaluate the economic feasibility of dairy manure digesters and co-digesters development in the Central Valley. The economic feasibility considers the costs and potential revenues under current economic conditions for manure digester and co-digester development. This analysis aims to provide an assessment of the economic feasibility of various dairy digester system configurations likely to be used in the Central Valley and to identify and evaluate the contribution and effects that the principal cost, revenue and financial parameters will have on the potential for future digester
development.

The economic model will be run to assess the economic feasibility of four proposed digester system configurations selected for relevance to reflect both current production/technology conditions as well as current market conditions for both dairy producers and potential biogas/biomethane consumers. The four digester system configurations are described in the draft report in the Proposed System Configurations to be Analyzed section beginning on page 9. Once the model runs are complete, the results and findings of the economic model runs of the four proposed system configurations will be included in a follow-up Economic Analysis Findings report which will be sent to the TAG for review and comment. Before the project team conducts the model runs we would like feedback from the TAG on the four digester system configurations that are being proposed (described below and in the draft report).

Any recommendations on the configurations will be considered prior to running the model. The economics team would also appreciate any non-proprietary economic data that you are willing to share (either published reports or data that you have developed) that may be relevant to running the model. If you have comments on the configurations or potentially relevant economic data please send your comments to me at j.tencati@circlepoint.com by Monday August 30.

The four digester system configurations are as follows:

**Farm-scale biogas production for on-site electrical generation.** The revenue and cost performance for a manure-only digester operating with a 1,000-cow dairy producing electricity with air quality compliant internal combustion engines.

**Pipeline injection scale biomethane production.** This configuration represents a large scale, high investment, technology intensive, low environmental impact scenario. The potential for such a facility (serving 10,000 cows) within close proximity to transmission will be assessed. This is the most market secure scenario for biomethane. The scale and biogas upgrade components are expected to be broadly representative of currently practiced biomethane production.

**Co-digestion of manure with available organic feedstocks.** The biogas production gains and tipping fees for co-digestion within a complete mix digester will be evaluated for a 1,000-cow dairy importing food waste from a nearby processor. Cost impact associated with any biogas quality changes as well as nitrogen and salt loading management issues will be identified and assessed.

**Centralized biomethane upgrade system with biogas transportation.** Most farms would not produce enough biogas to justify the cost of upgrading it to biomethane. Therefore, the financial feasibility of transporting biogas from ten 1,000-cow dairy digesters to a centralized biomethane upgrade unit will be evaluated. The potential for diseconomies of scale at a centralized facility will be considered.

Kind regards,
Jennifer

Jennifer Tencati
Project Manager

8/20/2010
Hi Paul,
Below please find a comment on the Draft Economic Feasibility Report from Allen Dusault.

- Jennifer

Jennifer,
I have only briefly reviewed the draft report and it appears to be well done. One issue that doesn’t come across is this. Whatever the financial merit or liability of the different digester facility scenarios, if you can’t get financing, they won’t be built. And right now it is difficult to get financing for biogas digesters. There should be some recognition of that and the connection between California’s challenging regulatory environment and the ability to finance new facilities. The issues are intimately related.

Allen

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8/20/2010
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Any recommendations on the configurations will be considered prior to running the model. The economics team would also appreciate any non-proprietary economic data that you are willing to share (either published reports or data that you have developed) that may be relevant to running the model. **If you have comments on the configurations or potentially relevant economic data please send your comments to me at j.tencati@circlepoint.com by Monday August 30.**

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Kind regards,
Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

8/20/2010
Hi Jennifer,

Can you elaborate on the fate of the biogas produced by configuration three (co-digestion) and four (centralized biomethane)? I would think that we would have to incorporate air quality compliant engines, microturbines, pipeline injection, etc, into an analysis of economic feasibility, particularly to compare the results to the first two configurations.

Dave Warner
Director of Permit Services
San Joaquin Valley APCD

Dear TAG Members:

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Kind regards,
Jennifer

Jennifer Tencati
Project Manager
j.tencati@circlepoint.com
916.658.0180 x131

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The whole view

455 Capitol Mall, Suite 802
Sacramento, CA 95814-4427

8/20/2010
Several contributors (including me) already have issues with the assumptions employed in the model. Apparently, previous comments on that topic were ignored in the preparation of the model. For example, on the utility side, there is no mention at all of gas quality testing costs or cost of compression into pipelines. Without consideration of all aspects of the projects and use of real-world assumptions, the model will have limited usefulness.

Ken Brennan
PG&E Product Management, Senior Product Manager  |  Office
415-973-0017; Cell 415-531-4173; Fax 415-973-6112  |  Email: kjbh@pge.com  |  Address: 245 Market Street, MC N15A, San Francisco, CA 94105

-----Original Message-----
From: Stephen Klein [mailto:sklein@waterboards.ca.gov]
Sent: Wednesday, October 27, 2010 11:22 AM
To: Brennan, Kenneth J (GT&D)
Subject: RE: Comments on Economic Modeling Report presented at TAG Meeting #4

Thanks, just re-emailed.

Stephen

>>> "Brennan, Kenneth J (GT&D)" <KJBh@pge.com> 10/27/2010 11:16 AM >>>
No attachment.

Ken Brennan
PG&E Product Management, Senior Product Manager  |  Office
415-973-0017; Cell 415-531-4173; Fax 415-973-6112  |  Email: kjbh@pge.com  |  Address: 245 Market Street, MC N15A, San Francisco, CA 94105

-----Original Message-----
From: Stephen Klein [mailto:sklein@waterboards.ca.gov]
Sent: Wednesday, October 27, 2010 11:12 AM
Subject: Comments on Economic Modeling Report presented at TAG Meeting #4

Hello TAG members,

Thank you for continuing to be a part of our Technical Advisory Group (TAG) for the California Regional Water Quality Control Board (Central Valley Water Board) Dairy Manure Digestion and Co-Digestion Program Environmental Impact Report (EIR).

Attached, is a copy of the Draft Economic Feasibility Modeling Findings for Dairy Manure Digester and Co-Digester Facilities that was presented at TAG meeting #4 on October 20th. We
appreciate all those who could attend the meeting. For those not at the meeting we had a lively 90-minute discussion of many aspects of the report and the modeling.

We would appreciate receiving any follow-up or additional written comments on the report from the TAG members by Friday November 12th. A final report will be distributed to the TAG members. The final report will take into consideration the comment letters and also include the comment letters as an appendix. This will allow all TAG members the opportunity to review comments on the report presented by other TAG members. Please submit any comments via email to sklein@waterboards.ca.gov

Kind regards,

Stephen James Klein, P.E., M.S.
Water Resources Control Engineer
Regional Water Quality Control Board - 5F
1685 E. Street
Fresno, CA 93706
(559) 445-5558
(559) 445-5910 (Fax)
Hi Steve, I like the different systems A-D. This does a good job of pointing out pros and cons of each design. I think you’ve struck on some of the complications in pipeline injection that needed to be pointed out. It doesn’t include a model similar to the proposed Pixley Biogas design—on site use of the biogas for other than electric generation. But that’s ok, no one will see us coming!

As far as shortcomings, it still doesn’t take into account the manure collection methodology. 1,000 cows can mean a lot of things, depending on how the manure is collected. I think you should at least clarify what percentage of the manure excreted by these cows is collected and inserted in the digester. Looking at the VS assumptions and footnotes, it looks like you’re assuming 100% collection? Maybe you should add that as a note somewhere.

Also, you might want to note that an air quality compliant piston engine isn’t that easy to come by. Maybe some of your TAG has more intimate knowledge, but I’m not positive there is an off-the-shelf 200 kW piston engine that can readily pass air board requirements. Everything I’ve seen requires customization and trial and error.

When it says a "complete mix" digester. Do you mean a controlled temperature digester (heated) or just an ambient temperature system, like a covered lagoon with a stirrer in it?

Who pays for these studies, how much did this one cost, and how does someone get the contract to prepare them?

Daryl Maas
Pixley Biogas
210-527-7631

-----Original Message-----
From: Stephen Klein [mailto:sklein@waterboards.ca.gov]
Sent: Wednesday, October 27, 2010 11:21 AM
Subject: Comments on Economic Modeling Report presented at TAG Meeting #4

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Kind regards,

Stephen James Klein, P.E., M.S.
Water Resources Control Engineer
Regional Water Quality Control Board - SF
1685 E. Street
Fresno, CA 93706
(559) 445-5558
(559) 445-5910 (Fax)
Mr. Klein:

Please find attached the comments of the Agricultural Energy Consumers Association (AECA) on the draft document entitled "Economic Feasibility Model Findings for Dairy Manure Digesters and Co-Digestion Facilities," prepared for the Central Valley Regional Water Quality Control Board.

If you have any questions, please feel free to contact me.

Dan Geis
Assistant Executive Director
Agricultural Energy Consumers Association
916.447.6206
November 11, 2010

RE: Comments on the draft “Economic Feasibility Model Findings for Dairy Manure Digesters and Co-Digester Facilities”

On October 20, 2010, the Agricultural Energy Consumers Association was present at a meeting related to the above-entitled document. These written comments are submitted to complement the verbal comments made at that meeting.

AECA is supportive of these continued efforts to better understand the potential of the agricultural industry to provide renewable energy resources to ratepayers and utilities. Biogas, solar, wind and hydroelectric power options all provide tremendous potential for our industry to assist California and the utilities in achieving the renewable energy goals the state has adopted.

What is energy worth?

The report appears to have correctly approximated the value of energy currently paid by the utilities for the feed-in tariff (FiT), as well as offset purchases under the retail electric rates. However, AECA believes that this analysis, based on the current regulatory scheme, may significantly underestimate the potential economic viability of these projects as other regulatory changes are adopted.

Senate Bill 32 (Negrete-McLeod – 2009) instructs the CPUC to improve and expand the price paid under the FiT in a manner that accounts and compensates the customer-generator for numerous positive environmental externalities. The CPUC has yet to implement this legislation, although it is expected to do so in the next few months. This may positively alter the economics related to the feasibility of all renewable energy projects, including dairy biogas digesters.

Currently, the CPUC is using the market price referent (MPR) as the proxy to establish the price paid under the FiT. This MPR price is based primarily on the cost of natural gas generation, which many parties believe is a poor proxy for renewable energy prices. AECA believes that SB 32 provides the CPUC with the tools to remedy this inadequate compensation.

In the last few months, there have been a number of decisions from the CPUC that show that the current FiT prices are too low. For example, the CPUC has recently adopted solar purchase programs for PG&E, SCE and SDG&E, in the same MW size range as would be applicable to dairy digesters, at a MPR-equivalent price of 19-20 cents/kWh.

AECA continues to advocate for the proper compensation of renewable energy projects by the regulated utilities of the CPUC. Electricity derived from biogas digestion is indeed a premium renewable commodity that
deserves a premium price. As such, we believe that the economic analysis contained in this report, which only values that energy at the current MPR levels, may ultimately be shortsighted. However, we do agree with the draft report’s basic conclusion that under the current regulatory scheme, dairy digesters appear to be uneconomic in most cases.

AECA recommends that the report include economic analysis across a range of prices, with the current MPR at the low end, and the proxy price paid under the aforementioned solar purchase program at the high end, to better understand where the economic viability of these types of projects begins.

Why isn’t Co-digestion included in all the analyses?

The draft report only analyzes co-digestion in the case of an electricity generating facility of 1,000 cows. It fails to include any analyses of co-digestion with respect to pipeline injection or larger scale operations. Despite the fact that the report finds that “potential major gains in biogas productivity may be obtainable at a relatively minor additional cost”, similar analyses were not conducted on the larger-scale projects.

AECA recommends that the final document include co-digestion additionality for the full range of size options for dairy biogas digesters.

The 18.5% assumed internal rate of return (IRR) may be low

Table 1 of the draft report assumes an 18.5% internal rate of return for investments in dairy biogas projects. AECA is concerned that this number may in fact be too low. The biogas industry in California has yet to be commercialized, and as such any new project carries a significant amount of risk. AECA has no specific recommendation for a different value, but does suggest that the report show economic feasibility across a range of different IRR assumptions.

Summary

AECA appreciates the opportunity to supply these brief comments on the draft report. We continue to support efforts to ensure the economic feasibility of dairy digesters, and appreciate the Regional Board’s continued attention towards this important program.

Sincerely,

Dan Geis
Assistant Executive Director
Stephen,

Thank you for the opportunity to comment on the economic modeling report. It is a robust analysis that highlights realistic challenges to the implementation of a dairy manure digester system. Acknowledging the range in key variables to costs, we have a few comments on the economic study:

1. The rate of return is listed at prime + 15%. Is that an average over the 15 year life of the project? 15% minimal return based on risk does not sound out of line when looking at investor-based funding sources, but is it worth considering in the realm of possibilities a lower rate of return for this category, say 12%?

2. The assumption of revenue from carbon credits ($2 to $3 per ton CO2e) appears low. With the cap and trade program now proposed, my socioeconomic staff are telling me that the price of viable credits should be more on the order of $6 per ton. This could make the difference of the project being in the black. It was not clear from the write-up (although I may have missed it) whether the price was wholesale or retail, which would make a difference. We would suggest the report give a range in revenue based on a rate of $2.25 to $6.00 per ton and highlight the impacts if the credits are more in the upper range. In any event, the report should more positively note that there is a potential for increased revenue from the carbon credit market now that the cap and trade regulations are out, particularly as it applies to a stream of credits from which revenue can help offset the capital cost of the equipment.

3. During the meetings, some time was spent as to the tipping fees being lower to mitigate the costs of transportation of food waste to the co-digester location. Perhaps the value could be presented as a range in transportation costs vs. tipping fee revenue, dependent on the location of the digester to an urban area generating the waste. With the uncertainties associated with the variables used to analyze project, we suggest reflecting costs as a comparative range, as opposed to a specified dollar amount.

Thank you again for opportunity and feel free to contact me with questions regarding these comments.

Tracy

~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~
Tracy A. Goss, P.E.
Program Supervisor, PM Strategies
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Email: tgoss@aqmd.gov
Ph: (909) 396-3106

-----Original Message-----
From: Stephen Klein [mailto:sklein@waterboards.ca.gov]
Sent: Wednesday, October 27, 2010 11:21 AM

Appendix A-301
Subject: Comments on Economic Modeling Report presented at TAG Meeting #4

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Appendix B
Acronyms and Glossary
## APPENDIX B

### Acronyms and Glossary

#### Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Glossary</th>
</tr>
</thead>
<tbody>
<tr>
<td>AB</td>
<td>Assemble Bill</td>
</tr>
<tr>
<td>ACEEE</td>
<td>American Council for an Energy Efficient Economy</td>
</tr>
<tr>
<td>BACT</td>
<td>Best Available Control Technology</td>
</tr>
<tr>
<td>CAFO</td>
<td>Confined Animal Feeding Operations</td>
</tr>
<tr>
<td>CARB</td>
<td>California Air Resources Board</td>
</tr>
<tr>
<td>CBG</td>
<td>Compressed Biomethane</td>
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<tr>
<td>CCAR</td>
<td>California Climate Action Registry</td>
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<tr>
<td>CEC</td>
<td>California Energy Commission</td>
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<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed Natural Gas</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed Generation</td>
</tr>
<tr>
<td>ERB</td>
<td>Emerging Renewables Program</td>
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<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>IC</td>
<td>Internal Combustion</td>
</tr>
<tr>
<td>IEUA</td>
<td>Inland Empire Utilities Agency</td>
</tr>
<tr>
<td>LCFS</td>
<td>California Low Carbon Fuel Standard</td>
</tr>
<tr>
<td>LBM</td>
<td>Liquefied Biomethane</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>MPR</td>
<td>Market Price Referent</td>
</tr>
</tbody>
</table>
### Glossary

- **Aerobic Bacteria**: Bacteria that require free elemental oxygen to sustain life.
- **Aerobic**: Requiring, or not destroyed by, the presence of free elemental oxygen.
- **AgSTAR**: A voluntary federal program that encourages the use of effective technologies to capture methane gas, generated from the decomposition of animal manure, for use as an energy resource.
- **Anaerobic Bacteria**: Bacteria that only grow in the absence of free elemental oxygen.
- **Anaerobic Lagoon**: A treatment or stabilization process that involves retention under anaerobic conditions.
- **Anaerobic**: A tank or other vessel for the decomposition of organic matter in the absence of elemental oxygen.
- **Anaerobic Digestion**: The degradation of organic matter including manure brought about through the action of microorganisms in the absence of elemental oxygen.
- **Best Management Practice (BMP)**: A practice or combination of practices found to be the most effective, practicable (including economic and institutional considerations) means of preventing or reducing the amount of pollution generated by nonpoint sources to a level compatible with water quality goals.

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
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</thead>
<tbody>
<tr>
<td>NCRS</td>
<td>Natural Resource Conservation Service</td>
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<tr>
<td>PIER</td>
<td>Public Interest Energy Research Program</td>
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<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
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<tr>
<td>ppm</td>
<td>Parts per million</td>
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<tr>
<td>PSA</td>
<td>Pressure Swing Absorption</td>
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<tr>
<td>REC</td>
<td>Renewable Energy Credits</td>
</tr>
<tr>
<td>RPS</td>
<td>Renewable Portfolio Standards</td>
</tr>
<tr>
<td>TAG</td>
<td>Technical Advisory Group</td>
</tr>
<tr>
<td>WDR</td>
<td>Waste Discharge Requirements</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
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<tr>
<td>-------------------------------------------</td>
<td>---------------------------------------------------------------------------</td>
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<tr>
<td>Biogas</td>
<td>Gas resulting from the decomposition of organic matter under anaerobic</td>
</tr>
<tr>
<td></td>
<td>conditions. The principal constituents are methane and carbon dioxide.</td>
</tr>
<tr>
<td>Biomass</td>
<td>Plant materials and animal wastes used especially as a source of fuel.</td>
</tr>
<tr>
<td>British Thermal Unit (BTU)</td>
<td>The amount of heat required to raise the temperature of one pound of</td>
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<td>water one degree Fahrenheit. One cubic foot of biogas typically contains</td>
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<tr>
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<td>about 600 to 800 BTUs of heat energy. By comparison, one cubic foot of</td>
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<tr>
<td></td>
<td>natural gas contains about 1,000 BTUs.</td>
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<tr>
<td>Carbon Offset (Carbon Credit)</td>
<td>A carbon offset purchase results in a reduction or avoidance of</td>
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<td></td>
<td>greenhouse gas emissions. The purchaser of the carbon offset entity pays</td>
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<tr>
<td></td>
<td>the seller not to emit or otherwise reduce the agreed amount of emissions.</td>
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<td></td>
<td>This may be achieved through various kinds of projects including</td>
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<td>renewable energy, methane capture, reforestation, improved energy</td>
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<tr>
<td></td>
<td>efficiency, etc. A key characteristic of a carbon offset is that it</td>
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<td></td>
<td>must be “additional” i.e. the offset provider must prove that the project</td>
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<td></td>
<td>would not have happened without its financial investment, and that the</td>
</tr>
<tr>
<td></td>
<td>project goes beyond “business as usual” activity.</td>
</tr>
<tr>
<td>Complete Mix Digester</td>
<td>A controlled temperature, constant volume, mechanically mixed vessel</td>
</tr>
<tr>
<td></td>
<td>designed to maximize biological treatment, methane production, and</td>
</tr>
<tr>
<td></td>
<td>odor control as part of a manure management facility with methane</td>
</tr>
<tr>
<td></td>
<td>recovery.</td>
</tr>
<tr>
<td>Composting</td>
<td>The biological decomposition and stabilization of organic matter under</td>
</tr>
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<td>conditions which allow the development of elevated temperatures as the</td>
</tr>
<tr>
<td></td>
<td>result of biologically produced heat. When complete, the final product</td>
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<tr>
<td></td>
<td>is sufficiently stable for storage and application to land without</td>
</tr>
<tr>
<td></td>
<td>adverse environmental effects.</td>
</tr>
<tr>
<td>Covered Lagoon Digester</td>
<td>An anaerobic lagoon fitted with an impermeable, gas- and air-tight cover</td>
</tr>
<tr>
<td></td>
<td>designed to capture biogas resulting from the decomposition of manure.</td>
</tr>
<tr>
<td>Demand charge</td>
<td>The peak kW demand during any quarter hour interval multiplied by the</td>
</tr>
<tr>
<td></td>
<td>demand charge rate.</td>
</tr>
<tr>
<td>Digestate</td>
<td>The sludge or spent slurry discharged from a digester. In this report</td>
</tr>
<tr>
<td></td>
<td>digestate generally refers to the dewatered solids portion of the spent</td>
</tr>
<tr>
<td></td>
<td>slurry, rather than the liquid digestate, which is referred to as the</td>
</tr>
<tr>
<td></td>
<td>effluent.</td>
</tr>
<tr>
<td>Digester</td>
<td>A concrete vessel used for the biological, physical, or chemical</td>
</tr>
<tr>
<td></td>
<td>breakdown of livestock and poultry manure.</td>
</tr>
<tr>
<td>Discount rate</td>
<td>The interest rate used to convert future payments into present values.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Down payment</td>
<td>The initial amount paid at the time of purchase or construction expressed as a percent of the total initial cost.</td>
</tr>
<tr>
<td>Drystack</td>
<td>Solid or dry manure that is scraped from a barn, feedlane, drylot or other similar surface and stored in a pile until it can be utilized.</td>
</tr>
<tr>
<td>Effluent</td>
<td>The discharge from an anaerobic digester or other manure stabilization process.</td>
</tr>
<tr>
<td>Energy Charge</td>
<td>The energy charge rate times the total kWh of electricity used.</td>
</tr>
<tr>
<td>Fats</td>
<td>Any of numerous compounds of carbon, hydrogen, and oxygen that are glycerides of fatty acids, the chief constituents of plant and animal fat, and a major class of energy-rich food. &quot;Fats are a principal source of energy in animal feeds and are excreted if not utilized.&quot;</td>
</tr>
<tr>
<td>Fixed Film Digester</td>
<td>An anaerobic digester in which the microorganisms responsible for waste stabilization and biogas production are attached to some inert medium.</td>
</tr>
<tr>
<td>Flushing System</td>
<td>A manure collection system that collects and transports manure using water.</td>
</tr>
<tr>
<td>Greenhouse Gas</td>
<td>An atmospheric gas, which is transparent to incoming solar radiation but absorbs the infrared radiation emitted by the Earth’s surface. The principal greenhouse gases are carbon dioxide, methane, and CFCs.</td>
</tr>
<tr>
<td>Hydraulic Retention Time (HRT)</td>
<td>The average length of time any particle of manure remains in a manure treatment or storage structure. The HRT is an important design parameter for treatment lagoons, covered lagoon digesters, complete mix digesters, and plug flow digesters.</td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>The annual rate of increase in costs or sales prices in percent.</td>
</tr>
<tr>
<td>Influent</td>
<td>The flow into an anaerobic digester or other manure stabilization process.</td>
</tr>
<tr>
<td>Internal Rate of Return</td>
<td>The discount rate that makes the NPV of an income stream equal to zero.</td>
</tr>
<tr>
<td>Kilowatt (kW)</td>
<td>One thousand watts (1.341 horsepower).</td>
</tr>
<tr>
<td>Kilowatt Hour (kWh)</td>
<td>A unit of work or energy equal to that expended by one kilowatt in one hour or to 3.6 million joules. A unit of work or energy equal to that expended by one kilowatt in one hour (1.341 horsepower-hours).</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Lagoon</td>
<td>Any large holding or detention pond, usually with earthen dikes, used to contain wastewater while sedimentation and biological treatment or stabilization occur.</td>
</tr>
<tr>
<td>Land Application</td>
<td>Application of manure to land for reuse of the nutrients and organic matter for their fertilizer value.</td>
</tr>
<tr>
<td>Liquid Manure</td>
<td>Manure having a total solids content of no more than five percent.</td>
</tr>
<tr>
<td>Loading Rate</td>
<td>A measure of the rate of volatile solids (VS) entry into a manure management facility with methane recovery. Loading rate is often expressed as pounds of VS/1000 cubic feet.</td>
</tr>
<tr>
<td>Loan Rate</td>
<td>The percent of the total loan amount paid per year.</td>
</tr>
<tr>
<td>Manure</td>
<td>The fecal and urinary excretions of livestock and poultry.</td>
</tr>
<tr>
<td>Mesophilic</td>
<td>Operationally between 80°F and 100°F (27°C and 38°C).</td>
</tr>
<tr>
<td>Methane</td>
<td>A colorless, odorless, flammable gaseous hydrocarbon that is a product of the decomposition of organic matter. Methane is a major greenhouse gas. Methane is also the principal component of natural gas.</td>
</tr>
<tr>
<td>Minimum Treatment Volume</td>
<td>The minimum volume necessary for the design HRT or loading rate.</td>
</tr>
<tr>
<td>Mix Tank</td>
<td>A control point where manure is collected and added to water or dry manure to achieve the required solids content for a complete mix or plug flow digester.</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>A combustible mixture of methane and other hydrocarbons used chiefly as a fuel.</td>
</tr>
<tr>
<td>Net Present Value (NPV)</td>
<td>The present value of all cash inflows and outflows of a project at a given discount rate over the life of the project.</td>
</tr>
<tr>
<td>NPV Payback:</td>
<td>The number of years it takes to pay back the capital cost of a project calculated with discounted future revenues and costs. Profitable projects will have an NPV Payback value less than or equal to the lifetime of the project.</td>
</tr>
<tr>
<td>Nutrients</td>
<td>A substance required for plant or animal growth. The primary nutrients required by plants are nitrogen, phosphorus, and potassium. The primary nutrients required by animals are carbohydrates, fats, and proteins.</td>
</tr>
<tr>
<td><strong>Operating Volume</strong></td>
<td>The volume of the lagoon needed to hold and treat the manure influent and the rain-evap volume.</td>
</tr>
<tr>
<td>----------------------</td>
<td>--------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Payback Years</strong></td>
<td>The number of years it takes to pay back the capital cost of a project.</td>
</tr>
<tr>
<td><strong>Plug Flow Digester</strong></td>
<td>A constant volume, flow-through, controlled temperature biological treatment unit designed to maximize biological treatment, methane production, and odor control as part of a manure management facility with methane recovery.</td>
</tr>
<tr>
<td><strong>Point Source Pollution</strong></td>
<td>Pollution entering a water body from a discrete conveyance such as a pipe or ditch.</td>
</tr>
<tr>
<td><strong>Process Water</strong></td>
<td>Water used in the normal operation of a livestock farm. Process water includes all sources of water that may need to be managed in the farm’s manure management system.</td>
</tr>
<tr>
<td><strong>Proteins</strong></td>
<td>Any of numerous naturally occurring extremely complex combinations of amino acids containing the elements carbon, hydrogen, nitrogen, and oxygen. Proteins are in animal feeds are utilized for growth, reproduction, and lactation and are excreted if not utilized.</td>
</tr>
<tr>
<td><strong>Renewable Energy Credits (RECs)</strong></td>
<td>Two commodities are created when renewable energy is generated: first, the actual physical energy, and second, a REC, which constitutes the property rights to the environmental benefits of the renewable energy production. The physical energy and the REC can be sold together, as ‘green energy.’ RECs can also be sold separately to traditional, non-renewable energy users, allowing that purchaser to make the valid claim that they are using renewable energy.</td>
</tr>
<tr>
<td><strong>Scrape System</strong></td>
<td>Collection method that uses a mechanical or other device to regularly remove manure from barns, confine buildings, drylots, or other similar areas where manure is deposited.</td>
</tr>
<tr>
<td><strong>Simple Payback</strong></td>
<td>The number of years it takes to pay back the capital cost of a project calculated without discounting future revenues or costs.</td>
</tr>
<tr>
<td><strong>Slurry (Semi-solid Manure)</strong></td>
<td>Manure having a total solids content between five and ten percent.</td>
</tr>
<tr>
<td><strong>Solids Manure</strong></td>
<td>Manure having a total solids content exceeding 10 percent.</td>
</tr>
<tr>
<td><strong>Storage Pond</strong></td>
<td>An earthen basin designed to store manure and wastewater until it can be utilized. Storage ponds are not designed to treat manure.</td>
</tr>
<tr>
<td>Term</td>
<td>Description</td>
</tr>
<tr>
<td>----------------------------------</td>
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</tr>
<tr>
<td>Storage Tank</td>
<td>A concrete or metal tank designed to store manure and wastewater until it can be utilized. Storage tanks are not designed to treat manure.</td>
</tr>
<tr>
<td>Straight-Line Depreciation</td>
<td>Depreciation per year equals the total facility cost divided by the years of depreciation (usually the facility lifetime).</td>
</tr>
<tr>
<td>Supplemental Heat</td>
<td>Additional heat added to complete mix and plug flow digester to maintain a constant operating temperature at which maximum biological treatment may occur.</td>
</tr>
<tr>
<td>Technical Advisory Group (TAG)</td>
<td>A working group of major stakeholders with knowledge and interest in dairy digesters; including the dairy industry, digester developers, utility companies, environmental and environmental justice groups, and state and local agencies.</td>
</tr>
<tr>
<td>Thermophilic</td>
<td>Operationally between 110°F and 140°F (43°C and 60°C).</td>
</tr>
<tr>
<td>Total Solids</td>
<td>The sum of dissolved and suspended solids usually expressed as a concentration or percentage on a wet basis.</td>
</tr>
<tr>
<td>Utility Interconnection</td>
<td>The method of utilizing electricity produced from manure management facilities. Options include either (1) on farm first use then sale to utility or (2) sale to the utility then direct purchase.</td>
</tr>
<tr>
<td>Volatile Solids</td>
<td>The fraction of total solids that is comprised primarily of organic matter.</td>
</tr>
<tr>
<td>Volatilization</td>
<td>The loss of a dissolved gas, such as ammonia, from solution.</td>
</tr>
<tr>
<td>Volumetric Loading Rate</td>
<td>The rate of addition per unit of system volume per unit time. Usually expressed as pounds of volatile solids per 1,000 cubic feet per day for biogas production systems.</td>
</tr>
</tbody>
</table>