Arnold Schwarzenegger
Governor

ECONOMIC STUDY OF BIOENERGY PRODUCTION FROM DIGESTERS AT DAIRIES IN CALIFORNIA

PIER FINAL PROJECT REPORT

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Prepared By:
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Prepared By:
Princeton Energy Resources International, LLC
Nicholas Cheremisinoff, Kathryn George, Joseph Cohen
Rockville, Maryland 20852
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Prepared For:
Public Interest Energy Research (PIER) Program
California Energy Commission

Zhiqin Zhang
Contract Manager

Gerry Braun
Program Area Lead
PIER Renewables

Ken Koyama
Office Manager
Energy Generation Research

Martha Krebs
Deputy Director
ENERGY RESEARCH & DEVELOPMENT DIVISION

Melissa Jones
Executive Director

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable and reliable energy services and products to the market place.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

- PIER funding efforts are focused on the following RD&D program areas:
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- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

The **Economic Study of Bio-Energy Production from Digesters at Dairies in California** is the final report for project work authorization #019-P-06 conducted by the Princeton Energy Resources International, LLC. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

This report, Economic Study of Bio-Energy Production from Digesters at Dairies in California, was prepared by Princeton Energy Resources International (PERI) under subcontract to Science Applications International Corporation (SAIC). The report sets forth cash flow financial analysis for nine dairy biogas digester projects installed under the California Dairy Power Production Program (DPPP), sized under 1 MW and producing electricity on-site. It projects other possible energy production scenarios, including for production of pipeline-quality gas, and production of power and pipeline-quality gas by enhanced environmental quality methods. For pipeline-quality gas, gas was assumed to be required to meet the quality standards of Pacific Gas & Electric (PG&E). Plant design was based on the existing biogas systems installed for power production, but was modified by removing engines and related equipment and adding biogas clean up equipment and pipelines to deliver gas from farm to nearest utility pipeline. Levelized Cost of Energy (LCOE) calculations, expressed as $/kWh or $/therm, were performed. Sensitivity analysis included benefits from selling carbon credits and utilizing the Section 45 Production Tax Credit for power cases.

Executive Summary

Economic studies of biogas digester systems installed under the California Dairy Power Production Program (DPPP) are performed for Actual, No Subsidy Power and Pipeline-Quality Gas, Enhanced Environmental Quality Power and Enhanced Environmental Quality Pipeline-Quality Gas, and various special sensitivity cases.

The Actual cases refer to economic analyses of dairy biogas power systems installed under the California DPPP when subsidies, such as grants, are included. Nine plants were analyzed for which full cost and operating data were available. Net incremental costs to produce power are identified and a Levelized Cost of Energy (LCOE) is calculated, expressed as $/kWh, in both nominal and constant-dollar amounts. Constant dollars exclude inflation.

The No Subsidy Power and Pipeline-Quality Gas cases refer to the economic analysis for dairy biogas power systems installed under the California DPPP when subsidies, such as grants, are excluded and certain standardized, common operating and finance assumptions are added. For the Power scenario, all power was assumed to be sold to the local utility at a rate utilizing a schedule based, not on net metering, but on California's Market Price Referent (MPR) rates. MPR is an estimate of the long-term market price of electricity, based on the long-term levelized price of power from a combined cycle natural gas plant. MPR rates are utilized to evaluate bids from power producers when utilities issue Renewable Portfolio Standard (RPS) solicitations. The Pipeline-Quality Gas case assumes all gas is sold to the local utility, under a natural gas pricing schedule.

Enhanced Environmental Quality Power and Enhanced Environmental Quality Pipeline-Quality Gas cases refer to a voluntary enhanced environmental quality practice that would reduce concern over water- and air-related environmental consequences of dairy operations. For this analysis, the No Subsidy Power and Pipeline-Quality Gas cases were upgraded by adding double liners to lagoons for covered lagoon systems and adding double liners to effluent storage lagoons for plug flow systems. For the plug-flow systems, the size of the storage lagoon is assumed to be the same size as the plug flow digester tank.

Two primary types of sensitivity analysis were performed. First, a break-even analysis was run, where the Internal Rate of Return (IRR) was reduced to about zero. Second, using a target IRR of 17%, LCOE was computed assuming the farmer/owner sold carbon credits and utilized the Section 45 Production Tax Credit (PTC) for power cases. Three example analyses including bonus depreciation, an augmented depreciation allowance for the year an asset is placed in service, were also run.

Results of the economic study for actual cases show that the three best returns belong to Hilarides Dairy, with an after-tax IRR at 22.82%, Castelanelli Bros. at 21.27%, and Blakes

Landing at 19.02%. The three next best show more modest returns, with one at break-even. However, the last three returns are negative, at about -13%.

Without a subsidy, the nominal LCOE, in 2007 dollars, may be characterized as high, tending to be above market rates. Results of the economic study for No Subsidy Power found that LCOEs varied from $0.1016 per kWh to $0.3716 per kWh. For the No Subsidy Pipeline-Quality Gas cases, the LCOE varied from $1.245 per therm to about $4.801 per therm.

Results of the economic study for the Enhanced Environmental Quality Power cases show that nominal LCOE in 2007 dollars varies from $0.1855 per kWh to $0.4486 per kWh. For power production, Enhanced Environmental Quality LCOEs without a subsidy are about 20% to 80% higher than the No Subsidy Power LCOEs for dairies with covered lagoons; they are 5% to 7% higher than the No Subsidy Power LCOEs for diaries with plug-flow digesters. For the Enhanced Environmental Quality Pipeline-Quality Gas cases, LCOE varies from $2.096 per therm to $5.819 per therm. One small dairy with a 12-mile pipeline represent a special case, at $35.128 per therm with the additional pipeline representing about 70% of total cost. In similar fashion as for power, Enhanced Environmental LCOEs without subsidies are about 10% to 70% higher than the No Subsidy Pipeline-Quality Gas LCOEs for diaries with covered lagoons; they are 3% to 4% higher than the No Subsidy Pipeline-Quality Gas LCOEs for dairies with plug-flow digesters.

Sensitivity study results show that for power generation, in general, the break-even LCOEs are 30% to 45% of those at 17% return. For pipeline-quality gas, breakeven LCOEs tend to be 30% to 42% of those at 17% return. Sensitivity study further shows that if the farmer sells carbon credits and utilizes the Section 45 Production Tax Credit (PTC) for power, project return improves and the LCOE can be reduced from about 10% to 30%. If the farmer sells carbon credits for pipeline-quality gas, project return improves and the LCOE can be reduced from about 4% to 15%, except for one special case that is much less. Three cases with 50% bonus depreciation were tested, and its use reduces LCOE from about 4% to 6% further.

This study shows that further research and field operation of anaerobic digestion (AD) biogas systems for dairy farms are needed to reduce capital costs and operating expenses, and to improve efficiency to the point where projects are more economically attractive. Grants or another form of subsidy are still needed to promote plant development to gain field experience.

If plant and equipment capital costs are reduced and if the plant operates efficiently at a high plant capacity factor, then LCOE can be reduced to a competitive range. Sensitivity analysis showed that, for No Subsidy Power, when operations at one dairy farm plant, that emphasized low capital cost by using refurbished equipment and that operated efficiently, were combined with options to sell carbon credits and to utilize the Section

45 PTC, this plant achieved an LCOE of $0.0680/kWh (nominal 2007 dollars). With 50% Bonus Depreciation, the LCOE declined to $0.0636/kWh.

Greater collaboration is required among dairy operators, utilities, permitting agencies, and funding and financing authorities to ensure an attractive price is paid that encourages efficient plant operation. This involves resolving existing issues on net metering, such as paying the farmer both for excess energy delivered and setting reasonable demand charges consistent with well operated, high capacity factor systems.

Alternatively, it involves developing attractive power purchase agreements for small power projects to buy excess energy (above the seller's on-site use) at attractive rates. New feed-in tariffs provide a mechanism for attractive power purchase, but low off-peak rates result in average electricity prices that are typically insufficient to justify base-load operation and the long term contracting requirements with no escalation clause may create uncertainty when weighing choices between feed-in tariffs and net metering. Feed-in tariffs may be combined with efforts to run the plant as a peaking operation, probably with some means of gas storage, such that the farmer sells mostly peak and partial-peak power.

Additional research and analysis is needed to assess the potential benefits, including increased gas production volumes, from codigesting additional feedstocks such as from food or food processing waste with manure. Also, additional revenues from sales of co-products from the AD process, e.g., fertilizer, livestock bedding material, should be evaluated for their impact on LCOE.

Most current plants are all equity financed, so there may be opportunities for aggregators or other developers to build larger anaerobic digester facilities. Such facilities would allow economies of scale in equipment and might be financed using non-recourse project finance including debt to improve economics. However, because manure management is integral to operation of the dairy farm, some farmers will want to maintain control and will continue to finance using all equity. A possible hybrid approach could be to aggregate equipment purchases and certain project design development and maintenance services to lower costs through standardization and bulk purchase discounts.

Regarding prices, some critics worry that a 20-year nominal flat price encouraged by MPR will be greatly under market prices near the end of its term if inflation were to increase. They would argue for a year one bid price that starts lower, but is accompanied by an annual escalator moving with some widely-accepted economic index (e.g., PPI, the Producer Price Index). At today's forecast of inflation, the bid price and escalator would be equivalent to MPR. But should inflation rise, the power producer would receive "fair" market prices, and would not receive such low prices that he or she abandons the project or, in the case of a farmer, where the dairy digester is a key component to farming, operates at a very low plant capacity factor. This is equivalent to suggesting the MPR be indexed. It is unlike the old "Standard Offer Number Four" contracts because rates are not fixed for ten years, based upon an old forecast of inflation that becomes outdated. Rates are not fixed for longer than one year, till they change with the index.

Lastly, as farmers seek to build more projects, state and other agencies might conduct outreach through meetings, written materials, and web-site information. Agencies might explain what materials and information are needed to obtain permits, such that farmers and their engineers could provide them quicker and with less revision.

1.0. Introduction

In 2001, the California Energy Commission (Energy Commission) initiated the California Dairy Power Production program in response to Senate Bill 5X (2001). A total of $10 million was earmarked for the development of manure methane power projects on California dairies. The program was designed to provide two types of assistance for qualifying dairy biogas projects: upfront, buy-down grants or five-year power production incentive payments. Buydown grants covered a maximum of up to fifty percent of the total capital costs of the biogas system based on designed power production, but not to exceed $2,000 per installed kilowatt (kW), whichever was less. Electricity production incentive payments were based on 5.7 cents per kilowatt-hour (kWh) of electricity generated by the dairy biogas system to be paid out over a maximum of five years.

From $10 million earmarked, by late 2005, $5.8 million was awarded to fourteen projects, as administered by Western United Resource Development (WURD).[1] Of the 14 projects, four decided not to construct digester systems, and ten completed projects. The *Dairy Power Production Program Dairy Methane Digester System Program Evaluation Report*, prepared for the Energy Commission by WURD and dated August 2006, provided data on construction, performance, and operating expenses for the ten completed projects. The ten dairy digester projects are:

- Hilarides Dairy; Lindsay, Tulare County, CA; 500 kW
- Cottonwood (Gallo Cattle); Atwater, Merced County, CA; 300 kW
- Blakes Landing Dairy; Marshall, Marin County, CA; 75 kW
- Castelanelli Bros. Dairy; Lodi, San Joaquin County, CA; 180 kW
- Koetsier Dairy; Visalia, Tulare County, CA; 260 kW
- Van Ommering Dairy; Lakeside, San Diego County, CA; 130 kW
- Meadowbrook Dairy; El Mirage, San Bernardino, CA; 160 kW
- Lourenco Dairy; Tulare, Tulare County, CA; 150 kW but no operational data
- Inland Empire Utilities Agency (IEUA); Chino, San Bernardino County, CA; 943 kW
- Eden-Vale Dairy; Lemoorre, Kings County, CA; 180 kW.

[1] Of the $10 million earmarked, the Energy Commission allocated $360,000 from the program to cover state administrative costs, leaving total program funds at $9,640,000. Of those program funds, $1,030,250 was allocated to WURD for program administrative costs. Due to the budget crisis, $2,817,380 was returned to the State General fund on March 2, 2005.

In late 2006, the remaining funding available from the four projects which decided not to construct digester systems was awarded to eight more dairy digester projects to be completed by 2008.

California is home to 1,950 dairies and 1.87 million milking cows. These cows represent 20% of 9.146million milking cows in the US and correspond to an estimated 166 million pounds of wet manure produced per day.[2,3]Capture of a portion of these wastes for anaerobic digestion represents a significant potential for greenhouse gas reduction and renewable energy generation.

Anaerobic digestion (AD), where organic material decomposes in the absence of air or oxygen) to produce medium-BTU digester gas, when coupled with modern manure management technology, has been identified as one of the most promising control technologies for converting dairy manure into renewable energy while reducing air and water pollution. However, research data are limited in both California and the US regarding the economic cost of biogas digesters. Such information is critical for dairy owners, project developers, utilities, engineers and equipment vendors, governmental agencies, and the public to understand current status, determine the next most cost-effective steps, and develop future renewable energy systems.

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[2] California Dairy Statistics Annual 2007, California Department of Food and Agriculture, Sacramento CA.

[3] J.A. Moore and M.J. Gamroth, Calculating the fertilizer value of manure from livestock operations, Oregon State University Extension Service. EC 1094, Reprinted Number 1993.

2.0. Objectives

The objectives of this study were developed as a joint effort among the California Energy Commission, the State Water Resources Control Board of the California Environmental Protection Agency, and Pacific Gas and Electric (PG&E), a major investor-owned energy utility in northern California serving four of the ten dairy digester power projects. The objectives were to quantify:

1) net incremental costs and levelized financial cost of electricity (in $/kWh) of dairy biogas power systems installed under the California Dairy Power Production program (DPPP)
2) net incremental costs and levelized financial cost of biogas (in $/therm, 1 therm = 100,000 Btu) if the dairy biogas produced from the digesters installed under the DPPP will be used to produce pipeline gas meeting natural gas quality standards (and/or PG&E standards)
3) net incremental costs and levelized financial costs of electricity and pipeline quality gas of adding anaerobic digestion capabilities to California dairies in an environmentally superior way.

For this study, the Levelized Costs of Energy (LCOE) are to be calculated both in nominal- and constant-dollar terms. Constant dollars exclude inflation.

3.0. Methodology

3.1. DCF-ROI (Discounted Cash Flow-Return On Investment) Cash Flow Model

For source data, this study uses construction, performance, and operating expense data from nine projects reported in the August 2006 report, Dairy Power Production Program (DPPP) Dairy Methane Digester System Program Evaluation Report, prepared by WURD.

PERI analyzed the nine dairy digester projects for which complete data were available (all the projects except Lourenco). Each project is located on a single farm, except for IEUA. Formed in 1950, IEUA is the water utility for an area comprising 242 square miles in western San Bernadino County that includes six dairies; the cities of Chino, Chino Hills, Fontana, Montclair, Ontario and Upland; and surrounding area.

PERI prepared a cash flow model and then performed discounted cash flow return on investment (DCF-ROI) analysis for each of the nine projects. From key plant data, including plant size, capital cost, performance (e.g., plant capacity factor, heat rate), operating expenses, depreciation and tax factors, contract term, inflation rate, and escalators, the model projects pro forma earnings and pro forma cash flows. For a fixed schedule of revenues, as with the nine "Actual Cases" described below, the model projects the plant's after-tax Internal Rate of Return (IRR). IRR is that rate at which the present value of the stream of after-tax cash flows to the owner equals the present value of his or her equity investment outlay.[4] From the fixed schedule of revenues and using a discount rate reflecting cost of capital, the model calculates the plant's Levelized Cost of Energy (LCOE), in nominal- and constant-dollar terms. LCOE is calculated by figuring the Net Present Value (NPV) of revenues using the nominal-dollar discount rate and then by levelizing the NPV, using either the nominal- or constant-dollar discount rate.

When revenues are not set in advance, and when it is desired that the project meet a target IRR, then, by trial and error, the model user enters a revenue schedule, checks IRR, and increases or decreases revenues, until the target IRR is reached. The target IRR may be termed a hurdle rate, for at or above it, the project will proceed, and under it, the project will be canceled (or modified until it meets the target). The model yields the plant's LCOE, in nominal and constant dollars, for the revenue schedule that meets the target IRR.

Detailed model assumptions are set forth in Table A- 1, Financial and Economic Assumptions, in the Appendix. In all cases, after-tax cash flow is calculated with the

[4] IRR is the break-even discount rate that causes the net present value of the project, calculated as upfront equity investment less all the years of discounted after-tax cash flows, to equal zero.

model first figuring project earnings, as revenues less operating expenses, less any interest on debt, less non-cash expenses (e.g., depreciation, amortization), to obtain before-tax profits, such that the income tax payment may be calculated. Next, the model figures cash flows, beginning with before-tax income, adding back non-cash expenses like depreciation and any other sources of cash (e.g., a reserve fund release), subtracting off non-deductible payments (e.g., principal on debt, payments to a reserve fund), and subtracting off the income tax payment, to obtain after-tax cash flow. To calculate IRR, the model seeks the discount rate where the farmer's equity investment, as a year zero payment, will equal the present value of future cash flows, as the sum of the discounted after-tax cash flows.

To calculate LCOE, the model begins with the project revenue stream. Employing a discount rate that reflects cost of capital, the model calculates a Net Present Value (NPV) of revenues using the nominal-dollar discount rate and levelizes that NPV to find one level payment that is the same for all years, using either the nominal- or constant-dollar discount rate. The level payment is divided by annual power production in kWh or annual gas production in therms, to obtain a unit cost. Note that the discount rate is set as the weighted-average cost of capital for a typical investor-owned utility. The discount rate is not the cost of capital for each dairy digester plant because they are all different. To compare plants easily, one discount rate is needed for all plants. The utility weighted-average cost of capital was selected for standardization and because the utility is the back-up source of power for the dairies. Both IRR and LCOE calculations are shown with the pro forma cash flows in Appendix B.

3.2. Plant Financing and Individual Plant Models.

Based on the information provided under the WURD's August 2006 report describing the nine actual dairy digester plants, there were no equipment loans or project debt. Consequently, for this study, all nine dairies are assumed to be financed on-balance sheet, with 100% equity or with equity plus a grant. There is no debt.

It is acknowledged that non-recourse or limited recourse project finance is used successfully by many independent power producers to finance, build, and operate plants employing a range of renewable energies and traditional fuel feedstocks. However, as a percentage of the total, project financing fees (e.g., legal and accounting fees, origination fees) tend to run high for small projects. Further, the debt and equity investors to such a financing are secured only by the project (with no recourse to the developer's other assets). To reduce their risk, such debt and equity investors will demand that the project obtain a long-term power purchase agreement or otherwise demonstrate a stable, reliable revenue stream.

For this study, the dairy digester power systems are relatively small, at under 1 MW. The power plant is a well-integrated part of the dairy farmer's total operation that is not easily separated out to serve as collateral for financing. Therefore, conservative, on-balance sheet, all-equity financing, where the farmer retains ownership and control, is assumed.

The target IRR or hurdle rate, which is the farmer's after-tax return on equity investment, is estimated as 17%. This rate is high because it is not guaranteed. A high degree of risk is involved, including construction risk and technology risk to get the digester power plant built and operating on-time and on-budget; operating risk over its projected 20-year life; regulatory risk regarding permits; and so forth. A high hurdle rate allows for slippage. Otherwise, an investor opts for risk-free Treasury bills and notes.

Finally, the existing cost and performance data from the nine AD systems is highly variable. Taking a simple average of cost data is not appropriate given the spread of data and high variability in plant design, plant capacity factors, equipment performance, heat rates, and other factors. Each of the nine plants required its own cash flow model. Analysis then was performed for several sets of cases, including "Actual," No Subsidy Power, No Subsidy Pipeline-Quality Gas, Enhanced Environmental Quality Power, Enhanced Environmental Quality Pipeline-Quality Gas, and various special sensitivity cases. As stated, to obtain LCOEs that are comparable, one standardized discount rate, which is the utility's weighted average cost of capital, was employed for all nine plants.

3.3. Economic Study for Actual Cases

Economic studies for actual cases refer to the dairy biogas power systems installed under California DPPP funding. Grants are included. The costs to produce power, as reported by WURD in their August 2006 report, are identified. Because revenues are specified, IRR is calculated, as are Levelized Costs of Energy (LCOE), expressed as $/kWh, in both nominal- and constant-dollar terms.

Regarding revenues, all nine dairy farmers sold power under net metering contracts. Thereby, farmers first added on-farm electric load to offset their retail rate, composed of both an energy portion (variable) and a demand/capacity portion (fixed). Because of contract mix-ups and for other reasons, some farmers received only the energy portion of the retail rate, at least for the study period. This analysis utilized the actual rates that farmers were paid, so it sometimes used low retail rates, reflecting only the energy portion of the payment.

Farmers second sold their surplus power to the utility for net metering credits, under a wholesale rate. Net metering credits are forfeited if the farmer does not use an equivalent amount of power on the farm within 12 months. Some portions of net metering credits were forfeited for five of nine plants. Some farmers flared gas versus producing power for no compensation from the utility. For this analysis, however, no net metering credits were assumed to be forfeited; all surplus power was sold to the utility.

To increase revenues, a few farmers added revenue savings streams from steam or heat use. One dairy, Cottonwood, added carbon credit sales, and IEUA's plant received a relatively small tipping fee, as payment from neighboring farmers to deposit manure there. As Table 1 shows, because of their grants, added revenue streams, and by operating efficiently, several farmers appeared to realize attractive returns on their AD energy systems.

3.4. Economic Study for No Subsidy Power and No Subsidy Pipeline-Quality Gas

Grants were removed to quantify LCOE on a no subsidy basis for the power and pipeline-quality gas cases. Non-incremental costs to building an AD system to produce energy were excluded. Because the farmer/owner seeks a target IRR of 17%, revenues to meet that return must be calculated by the model. From these revenues, an LCOE is calculated, in $/kWh, in both nominal- and constant-dollar terms.

For this scenario, all power was assumed to be sold to the local utility at a rate utilizing a schedule based on California's Market Price Referent (MPR) rates. MPR is an estimate of the long-term market price of electricity, based on the long-term levelized price of power from a combined cycle natural gas plant. MPR rates are utilized to evaluate bids from power producers when utilities issue Renewable Portfolio Standard (RPS) solicitations. The current base load MPR, in nominal dollars, under CPUC Resolution E-4118, effective October 4, 2007, for a project starting in 2008 with a 10-year contract is $0.09271 per kWh and, for a 20-year contract, is $0.09572. MPR rates vary by year of start-up, from about 2008 through 2020, and by whether the contract runs 10, 15, or 20 years. It is one rate that holds flat and does not escalate. Consequently, rates employed for No Subsidy Power and No Subsidy Pipeline-Quality Gas, as well as for all other cases, were held flat and did not escalate. For No Subsidy Power cases, plant design, cost and performance were assumed to follow fairly closely to the Actual Cases described above.

For No Subsidy Pipeline-Quality Gas cases, gas was assumed to be required to meet the quality standards of Pacific Gas & Electric (PG&E), California's large northern utility. Plant design was based on the Actual Power Cases, but was modified for producing gas, and removed engines and related equipment. A pipeline to deliver gas from farm to nearest utility pipeline was added.

To perform meaningful analysis, some degree of standardization and use of common assumptions for operation was required. Assumptions for the No Subsidy cases are described fully in Sections 4.2.1 and 4.3.1.

In addition to excluding the SB5X grants and attributing 100% energy sales to the utility using MPR-like rates, other key assumptions are as stated later. Non-incremental costs to building an AD system to produce energy were excluded. A small financing load (e.g., construction financing) was added and annual property taxes and insurance were added. For three plants with low plant capacity factors and low returns as Actual Cases, it was assumed that when attractive utility rates were available, the plants would operate with improved plant capacity factors and better heat rates.

3.5. Economic Study for Enhanced Environmental Quality Power and Pipeline-Quality Gas Cases

Enhanced Environmental Quality Power and Enhanced Environmental Quality Pipeline-Quality Gas cases refer to a voluntary enhanced environmental quality practice that would reduce concern over water- and air-related environmental consequences of dairy operations. For this analysis, the No Subsidy Power and Pipeline-Quality Gas cases were upgraded by adding double liners to lagoons for covered lagoon systems and adding double liners to effluent storage lagoons for plug flow systems. The size of the storage lagoon is assumed to be the same size as the plug flow digester tank.

3.6. Sensitivity Studies

Two primary types of LCOE sensitivity analyses were performed. First, a break-even analysis was run, where IRR was reduced to about zero. Second, with target IRR at 17%, the analysis looked to reduce LCOE by adding carbon credits and the Section 45 Production Tax Credit (PTC) for power cases. Three examples of Bonus Depreciation were also run.

4.0. Assumptions, Results, and Discussions

Assumptions, results, and discussion for Actual, No Subsidy Power, No Subsidy Pipeline-Quality Gas, Enhanced Environmental Quality Power and Enhanced Environmental Quality Pipeline-Quality Gas, and the various special sensitivity cases are presented as follows.

Certain basic economic and financial assumptions that are common to all cases (e.g., inflation rate, tax rate if the owner is taxable) inform the analysis. These are described in Table A- 1, Financial and Economic Assumptions, in the Appendix. More detailed assumptions can be found in the model spreadsheets for the nine dairy biogas power systems studied.

4.1. Economic Study for Actual Cases

4.1.1. Assumptions

Table 1 lists the key cost and performance parameters for each of the nine DPPP plants analyzed in this study. Complete cost and performance inputs for each plant are included in Table A- 2, Detailed Data Inputs for Nine Dairy Farm Digester Systems, in the Appendix. These farm-specific model inputs include:

- Introductory Data, such as farm location, herd size, and year of plant start-up;
- Plant Capital Costs, such as for manure collection, digester lagoon or tank, engine and gas treatment equipment, general construction, design, permits, and utility interconnection;
- Sources of Funds, composed of equity and grants, that match the upfront capital costs; and
- Technical and performance parameters and annual operating expenses, such as plant size, operating hours, quantity of power produced, fraction used on-farm (retail) versus sold to the utility (wholesale), any steam/thermal production, unit prices, plant heat rate, fuel heat content, and operating expenses and escalation factors.

4.1.2. Results and Discussion

Summary results of the economic study for actual cases are presented in Table 1. Full LCOE results are included in Table A- 3, Actual On-Site Power LCOEs, in the Appendix. Since revenues were given, the model calculated IRR. (For later cases, where a target IRR of 17% is given, the model calculates the LCOE/revenues required to produce that IRR.)

As shown, the three best returns belong to Hilarides, with an after-tax IRR at 22.82%, Castelanelli at 21.27%, and Blakes Landing at 19.02%. The three next best are

Table 1 – LCOE ($/kWh) and IRR Results for "Actual" Dairy Power Plant Cases

Dairy: Digester Type. Special notes.	Size (kW)	Plant Capacity Factor (%)	Annual Energy (MWh)	Heat Rate (Btu/kWh)	Capital Cost ($/kW Year $)	Capitalization % (Debt-Grant-Equity)	After-tax IRR (%)	Retail/ Whole-sale (%/%)	Year 1 Retail[2] ($/kWh)	Year 1 Whole-sale[2] ($/kWh)	Nominal LCOE[3] (2007$)	Constant LCOE[3] (2007$)
Hilarides: covered lagoon	500	77.23	3,383	13,132	2,480; 2005 $	0-40-60	22.82	62/38	.0600; 2006 $	.0400; 2006 $	.0643	.0524
Cottonwood: covered lagoon. Receives $30K/yr for carbon credits.	300	81.17	2,133	12,235	8,993; 2004 $	0-31-69	8.64	100/0	.0748; 2005 $	.0400; 2005 $	.0940	.0767
Blakes Landing: covered lagoon	75	38.48	253	13,813	4,504; 2004 $	0-46-54	19.02	60/40	.1200; 2005 $	.1000; 2005 $	.1409	.1149
Castelanelli: covered lagoon	160	81.00	1,135	17,912	6,043; 2004 $	0-57-43	21.27	50/50	.0724; 2005 $	.0576; 2005 $	.0817	.0666
Koetsier: Plug-flow	260	23.70	540	16,645	5,264; 2005 $	0-0-100[1]	-13.25	76/24	.0600; 2006 $	.0300; 2006 $	.0648	.0529
Van Ommering: Plug-flow	130	42.98	489	17,103	6,668; 2005 $	0-46-54	-0.12	10/90	.0500; 2006 $	.0500; 2006 $	.0613	.0500
Meadowbrook: Plug-flow	160	78.52	1,100	15,673	6,379; 2004 $	0-45-55	4.76	68/32	.0600; 2005 $	.0400; 2005 $	.0673	.0549
IEUA: modified mix plug-flow. Receives $18.6K/yr tip fee for manure.	943	91.67[4]	7,572	12,000[4]	13,734; 2005 $	0-01-99[1]	-13.78	100/0	.0800; 2006 $	.0400; 2006 $	.0981	.0800
Eden-Vale: Plug-flow	180	29.00	457	17,785	4,471; 2005 $	0-37-63	-13.97	17/83	.0700; 2006 $	.0300; 2006 $	.0449	.0366

1 Koetsier took their subsidy in the form of a 5-year production payment; IEUA took most of their subsidy as a 5-year production payment.

2 Year 1 Retail and Year 1 Wholesale prices in $/kWh are the average prices for year 1, and escalate at 2.50% inflation per year.

3 Nominal LCOE and Constant LCOE are levelized total prices that are a weighted average of retail and wholesale and that hold flat for 20 years.

4 Per February 15, 2008 PERI communication with IEUA, lately, digester system operating hours are significantly longer and operating expenses are lower than reported in WURD's August 2006 report, DPPP Dairy Methane Digester System Program Evaluation Report. Much digester gas is used for space and process heating but, here, all digester gas is assumed to be fed to the engine-generator and operating hours for the engine-generator equal those of the digester.

Cottonwood at 8.64%, Meadowbrook at 4.76%, and Van Ommering at -0.12%, which is about break-even. However, the last three returns are negative, including Koetsier at -13.25%, IEUA at -13.78%, and Eden-Vale at -13.97%.

Table 1 further shows that Levelized Cost of Energy for most of the projects, because revenues were assigned by the utilities under existing contracts, is in a competitive range. Specifically, excluding Eden-Vale, as a special case, and Blakes Landing, Nominal LCOE in 2007 dollars varies from $0.0613 per kWh to $0.0981 per kWh. All cost values in this chapter are expressed in nominal dollars of 2007 unless otherwise noted.

Table 1 and review of the nine Actual Cases suggest that different dairy owners employ different strategies to achieve success. For example, Hilarides Dairy, with an engine-generator of 500 kW, operating with a plant capacity factor of roughly 77%, generated 3,383 MWh/year, where 62% was used on-farm and valued at retail and the remaining 38% was sold to the utility for net generation credits and valued at wholesale. Unit prices were $0.0736/kWh retail and $0.0491/kWh wholesale. This structure allowed the plant to earn an IRR of 22.8%. The weighted average LCOE, combining retail and wholesale rates, is $0.0643/kWh. For the actual case, Hilarides received a "buy down" grant for 40% of capital cost. They held initial capital cost low by using refurbished equipment costing $2,480/kW, while other farms spent at least double that figure.

Cottonwood Dairy (Gallo Farms) pursued another strategy. Cottonwood Dairy, with an engine-generator of 300 kW, operating with a plant capacity factor of 81%, generated 2,133 MWh/year, with 100% of the power taken for on-farm use valued at the retail price of $0.0748/kWh (nominal levelized 2007$). The after-tax IRR for Cottonwood was 8.64%. Its capital cost was second highest, at $8,993/kW, but it received two grants that covered 31% of the capital cost. Cottonwood ran with high plant capacity factor and efficiency, its heat rate being the lowest of all dairies at 12,235 Btu/kWh, with exhaust heat recovered to produce steam and to preheat boiler feed water creating a significant thermal savings for the project. In addition, Cottonwood sold an estimated $30,000 per year in carbon credits. First year revenues are 58% power, 31% thermal, and 11% other. Despite higher costs, this dairy achieved an attractive IRR by operating efficiently and maximizing revenue.

Castelanelli Bros. Dairy installed an engine-generator of 160 kW, operated with a plant capacity factor of 81% and generated 1,135 MWh/year, where about 50% is taken for on-farm use at the retail price of $0.0910/kWh and the balance is sold under a net metering agreement and valued at wholesale, at a price of $0.0724/kWh (nominal levelized 2007$). Capital cost was fifth highest at $6,043/kW, but this plant received two grants that covered 57% of the plant's capital cost. Because of the grants, equity investment was reduced and after-tax IRR was 21.27%. With mid-level capital costs, by taking advantage of grants to reduce the owner's equity investment, by operating efficiently at a high plant capacity factor, and by adding load such that 50% of power was valued at retail rates, Castelanelli Bros. Dairy achieved an attractive IRR.

As a smaller dairy, Blakes Landing undertook a cherry-picking strategy. Operating with only a 38.5% plant capacity factor, Blakes Landing Dairy installed an engine-generator of 75 kW, generated 253 MWh/year, with 60% used on-farm and valued at retail and the remaining 40% sold to the utility for net generation credits and valued at wholesale. By selling mostly during peak periods, at prices of $0.1509/kWh retail and $0.1257/kWh wholesale (nominal levelized 2007$), the plant earned an IRR of 19.02%. Its capital cost was third lowest, at $4,504/kW, and it received two grants to cover 46% of the capital cost.

The dairy projects showing low returns in Table 1 tend to be special cases. Eden-Vale Dairy shows a negative return, partly because the plant came on-line in January 2006, was studied for only six months, and the dairy owner is planning to add more load to the engine-generator. In the meantime, while excess generation credits are forfeited, the plant runs at a 29% plant capacity factor, because the owner has opted not to run the plant at full capacity.

Likewise, because most net generation credits were forfeited, the Koetsier Dairy farmer does not run a second engine-generator that is on-site, underfuels the one in use to operate below design capacity, and flares part of the dairy biogas. The plant runs at a 24% plant capacity factor. The Koetsier project sought to refurbish an existing, non-operational plug-flow digester system, and over 70% of capital cost was incurred in 1985. Recently, the owner applied to sell carbon credits, so system performance and returns will improve.

Finally, for IEUA, expected construction costs nearly tripled from the time of application, in 2003, to construction. The complete cost, at $9.3 million, for the initial plug-flow digester is included, although some of the early equipment was discarded. Although this plant was in its start-up phase when WURD prepared their August 2006 report and indicated a nearly 18% plant capacity factor, recent contact with IEUA indicated the digester now operates 8,030 hours annually, for a 92% plant capacity factor, and operating expenses are now lower. IEUA also said the plant produces about half thermal energy and half power but, with information on thermal revenues not readily available, for this analysis, it was assumed that all gas is sent to the engine-generator to produce power. If this plant were built again, capital cost would be lower.

In summary, these nine Dairy Power Production plants are not static. The August 2006 WURD report indicated certain of the dairy plants planned to add on-site retail load, to expand, and to undertake other modifications towards operating more efficiently. Improved net metering terms and the advent of utility Standard Offer Contracts for small biomass plants may offer further incentive.

4.2. Economic Study for No-Subsidy Power Case

4.2.1. Assumptions

The No Subsidy Power cases are based very closely on the above-described Actual Cases. However, subsidies in the form of grants were removed. Standardization and common assumptions for operation were added. For three plants, plant capacity factors and heat rates were improved.

As with the Actual Cases, complete cost and performance inputs for each plant are listed in Table A- 2, Detailed Data Inputs for Nine Dairy Farm Digester Systems, in the Appendix. Data inputs for No Subsidy Power are in the second column, next to Data Inputs for Actual Cases, in the first column. These model inputs include Capital Costs, Sources of Funds, and Annual Performance and Operating Expenses.

Key changes include:

- SB5X grants are excluded; therefore financing is 100% equity.
- All power is assumed sold to the local utility. The rate paid is assumed to approximate MPR, so it is held flat and does not escalate. No power and no thermal energy are used on-site, to be valued at retail rates.
- Non-incremental costs were excluded. That is, because one goal of this study is to determine the net incremental cost to build an AD system and produce energy, those costs that are deemed part of the normal, basic cost of operating a dairy farm without energy production were removed. For example, the cost to dig a lagoon is not included, because lagoons to hold manure comprise a normal and ordinary component of operating a dairy. However, to produce usable digester gas to feed an energy system, the lagoon must be covered and lined, so the cost of lagoon covers and liners is considered an incremental cost of energy production.
- A small financing load, as a percentage of plant and equipment capital costs, was added. This covers construction financing, tax advice and accounting assistance, and a working capital reserve.
- Property taxes and insurance were estimated and added to annual expenses.
- All subsidies such as carbon credits were removed. (The lone exception is that a small tipping fee that the IEUA plant receives for accepting manure from neighboring farms was included because it was considered non-incremental.)
- No codigestion with a supplemental feedstock was assumed.
- Three plants with low actual plant capacity factors were assumed to operate better , with longer hours and less flaring of gas, when attractive utility rates were available, so their plant capacity factors were revised upward and their heat rates down. (It is noted that one small dairy farm, Blakes Landing, operates at a low capacity factor of 38.5%, but cherry picks, to match the hours of operation to peak periods, which maximizes the unit rate received and enables a

plant IRR of 19% as an actual case. It is not likely that this farm's owner would be motivated to run much longer hours, for a lower average unit revenue. Further, Blakes Landing operates with the fourth best heat rate and was reported to flare no gas. Consequently, its plant factor and heat rate were not adjusted.)

- All cases were run to achieve a target after-tax IRR of 17%.

4.2.2. Results and Discussion

Summary results for the No-Subsidy Power Case are presented in Table 2. Full LCOE results are included in **Table A- 4**, No Subsidy Power LCOEs, in the Appendix. One example case showing cash flows is presented with part 1 of Appendix B, Hilarides Dairy – No-Subsidy Power.

Table 2 shows how model inputs for No Subsidy Power scenario changed versus those for the Actual Cases. Specifically, versus Table 1, for each of the nine dairy plants, power plant size stayed the same. Plant capacity factor, electrical energy generated, and heat rate stayed the same for all except three plants, which were much improved. Capital cost per kW for each of the nine plants changed because non-incremental costs were excluded, which affected a few plants, and because a financing load was added.

Capitalization, the percentage of debt to grant to equity, became "0 – 0 – 100," for all nine plants. The after-tax IRR became 17% for all cases. The division of power sales, as percentage retail to percentage wholesale, became "0 – 100," for all cases.

Table 2 – LCOE ($/kWh) and IRR Results for No Subsidy Dairy Power Plant Cases

Dairy: Digester Type. Special notes.	Size (kW)	Plant Capacity Factor (%)	Annual Energy (MWh)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Capitalization % (Debt-Grant-Equity)	After-tax IRR (%)	Pct Retail/ Pct Whole-sale	Year 1 Retail[2]	Year 1 Whole-sale[2]	Nominal LCOE[3] (2007$)	Constant LCOE[3] (2007$)
Hilarides: covered lagoon	500	77.23	3,383	13,132	2,643; 2005 $	0-0-100	17.01	0/100	n/a	0.0991; 2006 $	0.1016	0.0828
Cottonwood: covered lagoon.	300	81.17	2,133	12,235	8,180; 2004 $	0-0-100	17.02	0/100	n/a	0.3375; 2005 $	0.3546	0.2891
Blakes Landing: covered lagoon	75	38.48	253	13,813	4,801; 2004 $	0-0-100	17.05	0/100	n/a	0.3540; 2005 $	0.3719	0.3032
Castelanelli: covered lagoon	160	81.00	1,135	17,912	6,070; 2004 $	0-0-100	17.02	0/100	n/a	0.2160; 2005 $	0.2269	0.1850
Koetsier: Plug-flow	260	83.45[1]	1,901	13,500[1]	5,611; 2005 $	0-0-100	17.03	0/100	n/a	0.1990; 2006 $	0.2040	0.1663
Van Ommering: Plug-flow	130	83.45[1]	950	13,500[1]	7,109; 2005 $	0-0-100	17.07	0/100	n/a	0.2550; 2006 $	0.2614	0.2131
Meadowbrook: Plug-flow	160	78.52	1,100	15,673	6,466; 2004 $	0-0-100	17.03	0/100	n/a	0.2630; 2005 $	0.2763	0.2253
IEUA: modified mix plug-flow. Receives $18.6K/yr tip fee for manure.	943	91.67	7,572	12,000	14,547; 2005 $	0-0-100	11.03	0/100	n/a	0.3350; 2006 $	0.3434	0.2799
Eden-Vale: Plug-flow	180	83.45[1]	1,316	13,500[1]	4,766; 2005 $	0-0-100	17.04	0/100	n/a	0.1720; 2006 $	0.1763	0.1437

1 Koetsier, Van Ommering, and Eden-Vale saw their plant capacity factors adjusted up and their heat rates adjusted down for No Subsidy Power cases

2 Year 1 Retail is moot here, because all power is assumed sold to the utility. Year 1 Wholesale prices in $/kWh reflect MPR schedule and do not escalate.

3 Nominal LCOE and Constant LCOE are levelized total prices that are a weighted average of retail and wholesale and that hold flat for 20 years.

Concise Levelized Cost of Energy results, as nominal LCOE and showing components, are shown below, in Table 3. Because a target IRR of 17% was assumed, the model calculated the LCOE/revenues required to produce that IRR.

As shown, nominal LCOE, in 2007 dollars, varies from $0.1016 per kWh for Hilarides to $0.3719 per kWh for Blakes Landing. All cost values in this case are expressed in nominal dollars of 2007 unless otherwise noted. LCOEs for the three projects that received an improvement to plant capacity factor, Eden-Vale, Koetsier, and Van Ommering, ranged from $0.1763 to $0.2614 per kWh, versus higher without the assumed improvements.

Table 3 - No Subsidy Power LCOE and Components (nominal levelized 2007$)

Dairy Name	No Subsidy Power LCOE – 17% IRR (¢/kWh)	After-tax O&M Component[1] (¢/kWh)	Capital Component (¢/kWh)
Hilarides	10.16	0.45	9.71
Eden-Vale[2]	17.63	1.16	16.47
Koetsier[2]	20.40	1.15	19.25
Castelanelli Bros.	22.69	0.94	21.75
Van Ommering[2]	26.14	1.61	24.53
Meadowbrook	27.63	2.71	24.92
IEUA	34.34	10.20	24.14
Cottonwood	35.46	4.34	31.12
Blakes Landing	37.19	1.16	36.03

1 Except for IEUA, after-tax O&M is O&M multiplied by (1 – 0.4075), where 40.75% is the combined tax rate. IEUA is tax-free, so no factor is applied to its O&M.
2 For Eden-Vale, Koetsier, and Van Ommering, adjustments to show more realistic plant operation were employed. These are that plant capacity factor was set to 83.45% and heat rates were reduced to 13,500 Btu/kWh. See Table 1 for previous rates.

Note that the after-tax Operations and Maintenance (O&M) component for most of the plants runs from about 3% to 7% of total LCOE. For Meadowbrook, Cottonwood and IEUA, the O&M component is higher. Cottonwood and IEUA have installed an iron sponge as part of their scrubber systems to remove hydrogen sulfide from biogas. Meadowbrook was researching equipment to scrub gas. The higher operating expense for these three plants may be related to maintaining air pollution control equipment, but further investigation is needed before drawing firm conclusions.

4.3. Economic Study for No-Subsidy Pipeline-Quality Gas Case

4.3.1. Assumptions

Another option for the dairy farmer with an anaerobic digester system is not to produce power on-site at the farm, but to sell gas to a utility so as to take advantage of economies of scale and the increased operating efficiency and air pollution control capacity of central power generation facilities (e.g., NGCC). PERI developed a second cash flow model for pipeline quality gas, where plant processing involves upgrading digester gas to clean, high-Btu natural gas equivalent or biomethane. Plant size is specified as thousand cubic feet per day (Mcf/day) of biogas at the inlet to the upgrading unit.

Cash flow results from the pipeline quality gas model are expressed in US dollars per therm (1 therm is equivalent to approximately 0.1 Mcf of methane). One Mcf of natural gas equivalent is estimated as 1.02 million Btu (abbreviated as 1.02 MMBtu), although the composition and heating value of natural gas varies by source and extent of blending.

The energy plant design for this option differs from the power-generating options by the absence of the engine gen-set, and related components. However, a gas clean-up and processing step must be added so that contaminant and diluent concentrations in the digester gas do not exceed utility pipeline specifications. Additional distribution pipeline capacity is added to convey upgraded biomethane from the farm to the nearest utility pipeline injection point.

Cost and performance changes to inputs are summarized in Table 4. As with the Actual Cases, complete cost and performance inputs for each plant are listed in Table A- 2, Detailed Data Inputs for Nine Dairy Farm Digester Systems, in the Appendix. Data inputs for No Subsidy Pipeline-Quality Gas are in the third column. Again, these model inputs include Capital Costs, Sources of Funds, and Annual Performance and Operating Expenses.

The pipeline-quality gas is assumed to meet PG&E quality standards. Costs related to the interconnection tap, controls and metering, unique interconnection facilities, and supervisory control and data acquisition (SCADA) monitoring were estimated, in part, based on ranges developed by PG&E[5].

Costs of gas clean-up were estimated by SCS Engineers (Sacramento, CA), who further estimated a 15% operating loss of biomethane through on-site use and leakage. Estimates of pipeline distances from farm to nearest utility pipeline were provided by the California Energy Commission. Costs for the distribution pipeline, the elimination of on-site electricity generating equipment, and other cost and operating data were developed by PERI.

[5] Pacific Gas & Electric Company, San Francisco CA, “Biogas White Paper (External Version),” received June 2007.

Table 4 – Pipeline Quality Gas Model Inputs: Costs and Expenses to Produce Gas instead of Power plus Revised Performance Effect

Dairy: Digester Type. Special notes.	Plant Capacity Factor (%)	Actual Biogas/day (Mcf/day)[1]	Pipeline[3]	Interconnect, Controls, Monitoring	Gas Clean-up & Processing	Reductions for Gas vs. Power in Capital Cost	Total Net Add'l Capital Cost	Per-formance Effect	Gas Monitoring Exp ($/yr)[4]
Hilarides: covered lagoon	90	232.7	50,000	250,000	720,000	(788,434)	231,566	-15%	10,000
Cottonwood: covered lagoon.	90	113.0	48,780	243,902	556,098	(199,064)	649,716	-15%	9,756
Blakes Landing: covered lagoon	90	14.8	2,474,146	243,902	390,244	(92,716)	3,015,577	-15%	9,756
Castelanelli: covered lagoon	90	89.1	1,053,659	243,902	468,293	(329,715)	1,436,139	-15%	9,756
Koetsier: Plug-flow	90	126.2[2]	50,000	250,000	400,000	(65,753)	634,247	-15%	10,000
Van Ommering: Plug-flow	90	52.0[2]	50,000	250,000	400,000	(204,362)	495,638	-15%	10,000
Meadowbrook: Plug-flow	90	80.5	48,780	243,902	448,780	(206,212)	535,251	-15%	9,756
IEUA: modified mix plug-flow.	90	384.2	50,000	250,000	570,000	(72,476)	797,524	-15%	10,000
Eden-Vale: Plug-flow	90	88.2[2]	50,000	250,000	400,000	(190,682)	509,318	-15%	10,000

1 Mcf is thousand cubic feet per day.

2 Actual biogas production before the adjustment in plant capacity factor was 44.19 Mcf/day at Koetsier, 33.94 Mcf/day at Van Ommering, and 40.36 Mcf/day at Eden-Vale. Such a large increase is possible because the dairy farmers have the cows available and are assumed to increase manure into the digester system and to stop flaring gas, if an economically attractive option exists.

3 Pipeline cost is $50/foot for distances less than 1 mile and $40/foot otherwise. Most pipelines are less than 1,000 feet, but that for Blakes Landing is about 12 miles and that for Castelanelli Bros. is about 5 miles.

4 For annual operating expenses, for Castelanelli, also omit expense to rebuild the engine, and for Meadowbrook, also omit expense to rebuild the engine and change oil frequently.

Many further assumptions for No Subsidy Pipeline-Quality Gas are similar to those for No Subsidy Power. These include that:

- SB5X grants are excluded.
- Financing was assumed to be all-equity.
- Non-incremental costs were excluded.
- A small financing load was added to up-front construction costs.
- Property taxes and insurance were added to annual expenses.
- Additional revenue streams were removed, except for IEUA's tipping fee.
- No codigestion with a supplemental feedstock was assumed.
- For gas production, all plants were assumed to operate with 90% plant capacity factors.
- All cases were run to achieve a target after-tax IRR of 17%.

4.3.2. Results and Discussion

Summary results for the cash flow analysis of costs and performance for the nine dairy digester projects selling No Subsidy Pipeline-Quality Gas are presented in Table 5. Full LCOE results are included in Table A- 5, No Subsidy Pipeline-Quality Gas LCOEs, in the Appendix. One example case showing cash flows is presented with part 2 of Appendix B, Hilarides Dairy – No-Subsidy Pipeline-Quality Gas.

Because the plant lay-out changed, summary data in the table changed. Plant size is Digester Size, expressed as thousand cubic feet/day-inlet (Mcf/day-inlet). Heat content of manure varies slightly by farm and is expressed as million Btu/Mcf. Annual gas sold is expressed as million Btu/day. Unit capital cost of the plant is expressed as $/million cubic feet per day-inlet of gas, and includes the 15% loss factor.

For example, the total loaded capital cost for Hilarides is estimated (Table A-2) as $1,568,589. The biogas production capacity is 232.7 Mcf/day, which translates to gross sustainable gas production after the 15% processing loss of 197.8 Mcf/day. There is assumed to be no in-plant use, so net sustainable gas production is also 197.8 Mcf/day. To check capital cost, an engineer might calculate net unit capital cost, which is $7,931,025 per million cubic feet per day. (Note that the plant's unit capital cost is expressed as dollars per million Btu because heat content of the raw material feedstock varies by farm, and a measure of dollars per thousand cubic feet would be constantly changing.)

As with No Subsidy Power, capitalization, the percentage of debt to equity, is 100% equity for all nine plants. The after-tax IRR is 17% for all cases. All gas is assumed sold to the utility with none used on the farm so the partitioning of percentage retail to percentage wholesale is "0 – 100," for all cases.

To highlight LCOE, concise results showing nominal LCOE and its components, as $/therm in 2007 dollars, are presented in Table 6. Because a target IRR of 17% was assumed, the model calculated the LCOE/revenues required to produce that IRR.

Table 5 – LCOE ($/therm) and IRR Results for No Subsidy Dairy Pipeline-Quality Gas Cases

Dairy: Digester Type. Special notes.	Size (Mcf/ day-inlet)	Plant Capacity Factor (%)	Annual Gas Sold (MMBtu/ day)	Manure Heat Content (MMBtu/ Mcf)	Capital Cost ($/million cf/day-inlet)	Capitalization % (Debt/Equity)	After-tax IRR (%)	Pct Retail/ Pct Whole-sale	Year 1 Retail[2]	Year 1 Whole-sale[2]	Nominal LCOE[3] (2007$)	Constant LCOE[3] (2007$)
Hilarides: covered lagoon	232.7	90.0	93.1	0.523	7,931,025; 2005 $	0-100	17.01	0/100	n/a	11.91; 2006 $	1.245	1.015
Cottonwood: covered lagoon.	113.0	90.0	54.7	0.633	32,772,514; 2004 $	0-100	17.02	0/100	n/a	44.80; 2005 $	4.801	3.914
Blakes Landing: covered lagoon, ~12 mi. pipeline	14.8	90.0	7.3	0.645	283,532,981; 2004 $	0-100	17.01	0/100	n/a	321.00; 2005 $	34.400	28.045
Castelanelli: covered lagoon, ~5 mi. pipeline	89.1	90.0	42.6	0.625	33,021,045; 2004 $	0-100	17.04	0/100	n/a	39.50; 2005 $	4.233	3.451
Koetsier: Plug-flow	126.2[1]	90.0	53.8	0.557	19,901,645; 2005 $	0-100	17.02	0/100	n/a	27.95; 2006 $	2.922	2.382
Van Ommering: Plug-flow	52.0[1]	90.0	26.9	0.676	32,862,932; 2005 $	0-100	17.03	0/100	n/a	38.50; 2006 $	4.025	3.282
Meadowbrook: Plug-flow	80.5	90.0	36.1	0.587	23,459,774; 2004 $	0-100	17.02	0/100	n/a	30.10; 2005 $	3.226	2.630
IEUA: modified mix plug-flow. Receives $18.6K/yr tip fee for manure.	384.2	90.0	190.4	0.648	44,611,060; 2005 $	0-100	11.04	0/100	n/a	38.30; 2006 $	4.004	3.265
Eden-Vale: Plug-flow	88.2[1]	90.0	37.2	0.552	18,692,810; 2005 $	0-100	17.03	0/100	n/a	26.90; 2006 $	2.812	2.293

1 Koetsier, Van Ommering, and Eden-Vale saw their power plant capacity factors adjusted up and biogas volume is based on that.

2 Year 1 Retail is moot here, because all gas is assumed sold to the utility. Year 1 Wholesale prices in $/MMBtu ($/million Btu) are geared to the MPR schedule, where prices are held flat (because this gas is feedstock to produce power), so they do not escalate. The Year 1 Wholesale price is the lowest price that gives a 17% IRR.

3 Nominal LCOE and Constant LCOE are levelized total prices that hold flat for 20 years.

As shown, the LCOE varies from $1.245 per therm for Hilarides to about $4.801 per therm for Cottonwood. Blakes Landing is a special case, because it is located far from any utility pipeline and must pay for and build a 12-mile pipeline, should it opt to produce pipeline-quality gas.

Note that the after-tax Operations and Maintenance (O&M) component for most of the plants runs from about 2% to 6% of total LCOE, excluding Blakes Landing (1%) and Cottonwood and IEUA, where the O&M component is higher. For pipeline-quality gas production, the annual expense for engine rebuild was dropped for Castelanelli Bros., and the annual expense for engine rebuild and frequent oil changes was dropped for Meadowbrook. Cottonwood and IEUA saw no change in operating expenses, which may be accurate or may reflect only that their operating expenses were broadly grouped and not finely classified.

Table 6 shows all plants incur an LCOE over $1.00/therm, which translates to $10/Mcf. All but one of the plants incur an LCOE over $2.50/therm, which is $25/Mcf. These are high costs.

Table 6 - No Subsidy Pipeline-Quality Gas LCOE and Components (nominal levelized 2007$)

Dairy Name	No Subsidy Gas LCOE, with 17% IRR ($/therm)[1]	After-tax O&M Component[2] ($/therm)	Capital Component ($/therm)
Hilarides	1.245	0.068	1.178
Eden-Vale	2.812	0.169	2.643
Koetsier	2.923	0.151	2.771
Meadowbrook	3.226	0.095	3.131
IEUA	4.004	1.151	2.853
Van Ommering	4.025	0.234	3.791
Castelanelli Bros. (~5 mile pipeline)	4.233	0.103	4.130
Cottonwood	4.801	0.511	4.290
Blakes Landing (~12 mile pipeline)	34.400	0.390	34.010

1 *Values may not sum due to rounding.*

2 *Except for IEUA, after-tax O&M is O&M multiplied by (1 – 0.4075), where 40.75% is the combined tax rate. IEUA is tax-free, so no factor is applied to its O&M.*

3 *To produce pipeline-quality gas, all plants were assumed to operate with a plant capacity factor of 90.0%.*

4.4. Economic Study for Enhanced Environmental Quality Power and Pipeline-Quality Gas Case

4.4.1. Assumptions

For comparison with the more conventional No Subsidy Power and No Subsidy Pipeline-Quality Gas scenarios, analyses were conducted for both power and biomethane generation under Enhanced Environmental Quality practices with greater attention to protecting water quality through the use of multiple liners on lagoons and effluent storage ponds. The promise of such an approach is that voluntary adoption of enhanced construction practices would allow overall design standardization with concomitant cost reduction. As more AD systems are built to standard and field operating experience is gained, plant operating performance should improve, concerns over water- and air-related environmental consequences of dairy operations should be mitigated; siting, regulation, and interconnection should be expedited; and costs should decline.

In the past, each dairy energy facility was considered unique, requiring extensive engineering and design on a dairy-by-dairy basis. Historically, permitting a anaerobic digester project at a dairy has required submission of detailed engineering and design information and extensive review by permitting agencies.

An example of the benefit of using an "environmentally superior" design is found in General Waste Discharge Requirements (WDR) Order No. R5-2007-035 adopted by the Central Valley Regional Water Quality Control Board (RB5) in May 2007. For ponds that meet the Tier 1 design, the WDR Order states that reviews *"will be conducted in less than 30 days of receipt of a complete design plan package submitted to the Board."*

Consequently, for this analysis the No Subsidy Power and Pipeline-Quality Gas cases were upgraded with a double liner under lagoons and storage ponds. To meet the Tier 1 design, liners are assumed to be made of high performance, advanced material (e.g., high density polyethylene or HDPE), and a leachate monitoring system is installed, to ensure there are no leaks from the lined lagoon. As part of leachate monitoring, a modest annual water sampling and testing expense is charged to all plants. For covered lagoon systems, the double liner is applied to the bottom and side walls of the lagoon. For plug-flow systems, where anaerobic digestion of manure takes place in a concrete digester tank, the double liner is applied to the effluent storage lagoon located downstream of the digester that is assumed to be of the same working volume as the plug flow digester. Liner material and cost information was obtained by PERI engineers through communication with contract and consulting engineers having field experience in California.

Note, however, that the effluent from both covered lagoon and plug-flow digesters is typically discharged to storage ponds for storage prior to application to cropland, and that the storage ponds may require lining to ensure that the overall dairy waste management system is protective of groundwater. If installing a digester at a dairy requires construction of a new effluent storage pond, that pond too may need to be lined to ensure rapid processing of the application.

However, the current analysis assumed that covered lagoons were lined and that effluent storage ponds for plug-flow digester systems were lined. The Enhanced Environmental Quality cost and expense changes are summarized in Table 7. Note that the cost of lagoon excavation is not included, because lagoon excavation is considered a normal part of dairy operation in California. Likewise, the cost of lagoon covers is not included, because they also are considered a normal part of dairy operation in California.

Table 7 – Enhanced Environmental Quality Additional Costs and Performance Effect for Power and Pipeline-Quality Gas

Dairy: Digester Type. Special notes.	Lagoon Size	Leachate Monitoring: one well/farm[1]	Double Liner (at $1.85/sq ft) [1]	Leachate Monitoring Expense ($/year) [2]	Performance Effect[3]
Hilarides: Covered lagoon	First: 1,100 x 220 x 18 ft; Second: 1,100 x 220 x 15 ft.	$11,000	$535,612; $520,960	7,000	Nil
Cottonwood: covered lagoon.	1,213 x 267 x 24 ft.	$10,732	$712,766	6,829	Nil
Blakes Landing: covered lagoon	150 x 60 x 12 ft.	$10,732	$29,672	6,829	Nil
Castelanelli: covered lagoon	550 x 150 x 28 ft.	$10,732	$219,654	6,829	Nil
Koetsier: Plug-flow	30 x 180 x 16 ft.	$11,000	$22,422	7,000	Nil
Van Ommering: Plug-flow	30 x 130 x 12 ft.	$11,000	$14,319	7,000	Nil
Meadowbrook: Plug-flow	32 x 156 x 14 ft.	$10,732	$18,511	6,829	Nil
IEUA: modified mix plug-flow.	195 x 60 x 16 ft.	$11,000	$36,741	7,000	Nil
Eden-Vale: Plug-flow	30 x 150 x 14 ft.	$11,000	$17,649	7,000	Nil

1 *Costs for plants constructed in 2004 are reduced by one year's inflation, estimated as 2.50%, vs. those constructed in 2005.*

2 *Plant construction is estimated as one year. Consequently, plant start-up takes place one year after plant construction. Expenses for plants starting up in 2005 also are reduced by one year's inflation, at 2.50%, vs. those starting up in 2006.*

3 *Plants achieve the same power or gas production as before, with No Subsidy cases.*

Table 7 does not include costs for enhanced protection of air quality. The San Joaquin Valley Air Pollution Control District (SJVAPCD) has identified the use of anaerobic digesters at dairies as more protective of air quality than open storage. However, because the cost per unit reduction in priority pollutants resulting from use of anaerobic digesters is high, it has not been identified as Best Available Control Technology (BACT). Also, using biogas from an anaerobic digester to run an internal combustion engine to power a generator results in emissions of nitrogen oxides (NOx). Thus, although anaerobic digesters are themselves an enhancement for protection of air quality, it appears necessary to reduce or prevent NOx emissions through further enhancements.

NOx emissions can be reduced by not using biogas to generate electricity but instead injecting the biogas into a utility company pipeline as described in Section 4.3. Injecting the biogas leave only occasional operation of a flare as a combustion source of NOx, but gas clean-up and transport is costly. Another option is to install air pollution control equipment to reduce NOx and hydrogen sulfide (H2S) emissions. One expert has suggested that new dairy digesters "may or will require air permits."[6]

For this analysis, assumptions for the Enhanced Environmental Quality cases follow those for No Subsidy Power and No Subsidy Pipeline-Quality Gas, such as for plant capacity factor. Assumptions include:

- SB5X grants are excluded.
- Financing was assumed to be all-equity.
- Non-incremental costs were excluded.
- A small financing load was added to up-front construction costs.
- Property taxes and insurance were added to annual expenses.
- Additional revenue streams were removed, except for IEUA's tipping fee.
- All cases were run to achieve a target after-tax IRR of 17%.

Economic and financial assumptions remain the same as for the No Subsidy cases.

4.4.2. Results and Discussion

Two sets of results for the cash flow analysis for the nine dairy digester projects employing voluntarily Enhanced Environmental Quality guidelines were prepared, for Power and for Pipeline-Quality Gas. Because target IRRs of 17% were assumed, the model calculated the LCOE/revenues required to produce those IRRs.

Cost changes were mostly small in comparison to the No Subsidy Power and No Subsidy Pipeline-Quality Gas cases. Hilarides is the exception, with an 83% increase in LCOE for electricity. All others are under 27% increase. Unit capital cost increased because of the double liners and leachate monitoring systems. Operating expense increased due to annual monitoring expense, but this is minor.

The summary results for the Enhanced Environmental Quality Power and Pipeline-Quality Gas Cases showing nominal LCOE and its components as $/kWh and $/therm, in 2007 dollars, are presented in Table 8 and Table 9. Full LCOE results are included in Table A- 6 and Table A- 7 in the Appendix.

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[6] Rob Williams, Biological and Agricultural Engineering, California Biomass Collaborative; University of California, Davis; "Biomass Systems for Heat and Power," presentation for Smart Energy Management in Agriculture conference, through The Ecological Farming Association, Winters CA, November 13, 2007.

Table 8 – Enhanced Environmental Quality (EEQ) Power LCOE and Components (nominal levelized 2007$)

Dairy Name	EEQ Power LCOE – 17% IRR (¢/kWh)	EEQ Power After-tax O&M Component[1] (¢/kWh)	EEQ Power Capital Component (¢/kWh)	No Subsidy Power LCOE – 17% IRR (¢/kWh)	Percentage Increase: EEQ Power/ No Subsidy Power
Hilarides covered lagoon	18.55	0.60	17.95	10.16	83%
Eden-Vale[2] plug-flow	18.86	1.55	17.31	17.63	7%
Koetsier[2] plug-flow	21.32	1.41	19.91	20.40	5%
Van Ommering[2] plug-flow	27.68	2.14	25.54	26.14	6%
Castelanelli Bros. covered lagoon	28.79	1.39	27.40	22.69	27%
Meadowbrook plug-flow	29.10	3.17	25.93	27.63	5%
IEUA modified mix plug-flow	34.54	10.31	24.23	34.34	1%
Blakes Landing covered lagoon	44.65	3.18	41.47	37.19	20%
Cottonwood covered lagoon	44.86	4.58	40.28	35.46	27%

1 For all plants except IEUA, after-tax O&M is O&M multiplied by (1-0.4075), reflecting a reduction for the combined tax rate of 40.75%. Since IEUA is tax-free, no factor is applied for it.
2 Eden-Vale, Koetsier, and Van Ommering were adjusted to employ a better plant capacity factor of 83.45% and an improved heat rate of 13,500 Btu/kWh.

Nominal LCOE for the Enhanced Environmental Quality Power cases in 2007 dollars varies from $0.1855 per kWh for Hilarides to $0.4486 per kWh for Cottonwood. These cases compare very closely to No Subsidy Power except that construction cost is higher and operating expense is slightly higher.

LCOEs for Enhanced Environmental Quality Power are about 20% to 80% higher for dairies with covered lagoons compared to the No Subsidy Power cases. Enhanced Environmental Quality LCOEs are about 5% to 7% higher for dairies with plug-flow digesters, and only about 1% higher for IEUA with its modified mix plug-flow system. The primary difference is the size of covered lagoons used as digesters in comparison to the effluent storage ponds used by plug-flow systems. Table 7 shows many of the covered lagoon digesters are large, occupying a large surface area, with two over 20 feet deep. By contrast, the plug-flow digesters, which employ a concrete tank, are smaller and their capital cost for the double liner on an effluent storage pond is less.

Table 9 - Enhanced Environmental Quality Pipeline-Quality Gas LCOE and Components (nominal levelized 2007$)

Dairy Name	EEQ Gas LCOE, with 17% IRR ($/therm)	After-tax O&M Component[1] ($/therm)	Capital Component ($/therm)	No Subsidy Gas LCOE, with 17% IRR ($/therm)	Percentage Increase: EEQ Gas/ No Subsidy Gas
Hilarides covered lagoon	2.096	0.083	2.013	1.245	68%
Eden-Vale plug-flow	2.927	0.207	2.720	2.812	4%
Koetsier plug-flow	3.011	0.178	2.834	2.923	3%
Meadowbrook plug-flow	3.354	0.134	3.220	3.226	4%
IEUA modified mix plug-flow	4.025	1.164	2.861	4.004	1%
Van Ommering plug-flow	4.172	0.287	3.885	4.025	4%
Castelanelli Bros. (~5 mile pipeline) covered lagoon	4.683	0.137	4.546	4.233	11%
Cottonwood covered lagoon	5.819	0.537	5.282	4.801	21%
Blakes Landing (~12 mile pipeline) covered lagoon	35.128	0.584	34.544	34.400	2%

1 For all plants except IEUA, after-tax O&M is O&M multiplied by (1-0.4075) reflecting a reduction for the combined tax rate of 40.75%. Since IEUA is tax-free, no factor is applied for it.

2 To produce pipeline-quality gas, all plants were assumed to operate with a plant capacity factor of 90.0%.

For the Enhanced Environmental Quality Pipeline-Quality Gas cases, LCOE varies from $2.096 per therm for Hilarides to $5.819 per therm for Cottonwood. Blakes Landing and its 12-mile pipeline represent a special case, at $35.128 per therm. Note that acquisition of rights-of-way and other off-site access were not incorporated into the overall pipeline extension cost estimates applied here.

Similar to the case of power, the LCOEs for Enhanced Environmental Quality Pipeline-Quality Gas are about 10% to 70% higher than those for No Subsidy Pipeline-Quality Gas for dairies with covered lagoons, excluding Blakes Landing. Enhanced Environmental LCOEs are only about 3% to 4% higher for dairies with plug-flow digesters, consistent with the smaller sizes of the effluent storage ponds, and about 1% higher for IEUA with its modified system.

4.5. Sensitivity Analysis

4.5.1. Break-even Analysis

Assumptions

To investigate sensitivity of the Cost of Energy, a break-even analysis was run with after-tax Internal Rate of Return set to zero (0% IRR). The purpose was not to set rates so low that the farmer fails to make a return on investment, but rather to examine the variation in LCOE throughout the range of IRR to breakeven. Investors of capital would instead opt for safe, risk-free Treasury securities if breakeven were their only choice.

Furthermore, returns are high because they are not guaranteed and because the high rate allows for slippage in capital costs, operating expenses, and plant performance. The purpose of the break-even case is to learn the magnitude of the effect of high return on capital on Levelized Cost of Energy.

Because the dairy power plants are capital-intensive, with the owner required to invest a large sum of money up-front to build the plant, and because conservative all-equity financing is assumed, a high return on capital is expected, which will have a significant effect on LCOE. Break-even analysis was run for both No Subsidy power and No Subsidy pipeline-quality gas cases.

Results and Discussion

Two sets of results for break-even cash flow analysis for the nine dairy digester projects were prepared, for Power and for Pipeline-Quality Gas. Because target IRRs of 0% were requested, the model calculated the LCOE/revenues required to produce those IRRs.

In comparing the breakeven cases with the respective No Subsidy Power or No Subsidy Pipeline-Quality Gas cases, capital cost, performance, and operating expense were unchanged. Only the investor's return changed. The breakeven summary results for power and pipeline gas are presented in Table 10 and Table 11. Full LCOE results are included in Tables A- 8 and A-9 in the Appendix.

Table 10 – No Subsidy Power LCOE and Components (nominal levelized 2007$) for Breakeven (0%) and 17% Equity Returns

Dairy Name	Breakeven			17% IRR		
	No Subsidy Power LCOE – (¢/kWh)	After-tax O&M Portion[1] (¢/kWh)	Capital Portion (¢/kWh)	No Subsidy Power LCOE – (¢/kWh)	After-tax O&M Portion[1] (¢/kWh)	Capital Portion (¢/kWh)
Hilarides	3.49	0.45	3.04	10.16	0.45	9.71
Eden-Vale[2]	6.46	1.16	5.30	17.63	1.16	16.47
Koetsier[2]	7.18	1.15	6.03	20.40	1.15	19.25
Castelanelli Bros.	7.56	0.94	6.62	22.69	0.94	21.75
Van Ommering[2]	9.33	1.61	7.72	26.14	1.61	24.53
Meadowbrook	11.24	2.71	8.53	27.63	2.71	24.92
IEUA	21.22	10.20	11.02	34.34	10.20	24.14
Cottonwood	15.65	4.34	11.31	35.46	4.34	31.12
Blakes Landing	11.77	1.16	10.61	37.19	1.16	36.03

1 After-tax O&M is multiplied by (1-0.4075) except for IEUA, which is tax-free.

2 Eden-Vale, Koetsier, and Van Ommering were adjusted to employ an improved 83.45% plant capacity factor and 13,500 Btu/kWh heat rate.

LCOE with a zero percent return is $0.0718 per kWh for Koetsier Dairy versus $0.2040 per kWh with a 17% return. Generally, the breakeven LCOE's are 30% to 45% of those at 17% return. The one exception is IEUA, which is tax-free, so the break-even LCOE is 62% of the full LCOE at 11% return, where the tax-free target of 11% IRR is employed instead of 17%.

Table 11 - No Subsidy Pipeline-Quality Gas LCOE and Components (nominal levelized 2007$) for Breakeven (0%) and 17% Equity Returns[2]

Dairy Name	Breakeven			17% IRR		
	No Subsidy Gas LCOE, ($/therm)	After-tax O&M Portion[1] ($/therm)	Capital Portion ($/therm)	No Subsidy Gas LCOE, ($/therm)	After-tax O&M Portion[1] ($/therm)	Capital Portion ($/therm)
Hilarides	0.439	0.068	0.371	1.245	0.068	1.178
Eden-Vale	1.004	0.169	0.835	2.812	0.169	2.643
Koetsier	1.014	0.151	0.863	2.923	0.151	2.771
Meadowbrook	1.018	0.095	0.923	3.226	0.095	3.131
IEUA	2.447	1.151	1.295	4.004	1.151	2.853
Van Ommering	1.422	0.234	1.188	4.025	0.234	3.791
Castelanelli Bros. (~5 mile pipeline)	1.297	0.103	1.194	4.233	0.103	4.130
Cottonwood	2.015	0.512	1.503	4.801	0.511	4.290
Blakes Landing (~12 mile pipeline)	9.945	0.390	9.555	34.400	0.390	34.010

1 After-tax O&M is multiplied by (1-0.4075) except for IEUA, which is tax-free.

2 For pipeline-quality gas, all plants operate with a plant capacity factor of 90.0%.

For pipeline-quality gas, LCOE with a zero percent return is $1.018 per therm for Meadowbrook Dairy, versus $3.226 per therm at 17% return. Similar to power, the breakeven LCOE's tend to be 30% to 42% of those at 17% return. The two exceptions are Blakes Landing with its hugely expensive 12-mile pipeline at 29% and tax-free IEUA at 61%.

In conclusion, one lesson to draw is that much can be achieved by reducing the underlying capital cost of the dairy digester energy plant. This reduces upfront investment from farmers or other investors and is more useful than trying to reduce their return on investment.

4.5.2. Impacts of Carbon Credits, Production Tax Credits, and Bonus Depreciation

Assumptions

This section investigates reducing LCOE through tax and other credits of various types. These include selling carbon credits, utilizing federal internal revenue code Section 45 renewable energy production tax credits, and applying bonus depreciation under the federal tax code.

Carbon credits, measured as a price per metric ton of carbon dioxide equivalent, are currently traded at the Chicago Climate Exchange (CCX), which operates a voluntary, legally binding, greenhouse gas reduction and trading system. Credits are available for a variety of projects, such as forestry carbon sequestration (afforestation), landfill methane capture, etc. Credits are available for dairy digester projects for methane reduction and for power production from a renewable energy source.

For this analysis, the carbon credit price was estimated at a conservative value of $3.00 per metric ton of carbon dioxide equivalent. At the CCX, the credit price has ranged from about $1.00 to about $4.00 from 2004 through 2007. Recently, it reached $6.00 per MT CO2 equivalent.

As a point of contrast, projections by the Intergovernmental Panel on Climate Change (IPCC) and the European Union utilize estimates ranging up to $100 per metric ton CO_2 equivalent for purposes of stimulating changes to mitigate climate change impacts.[7, 8]

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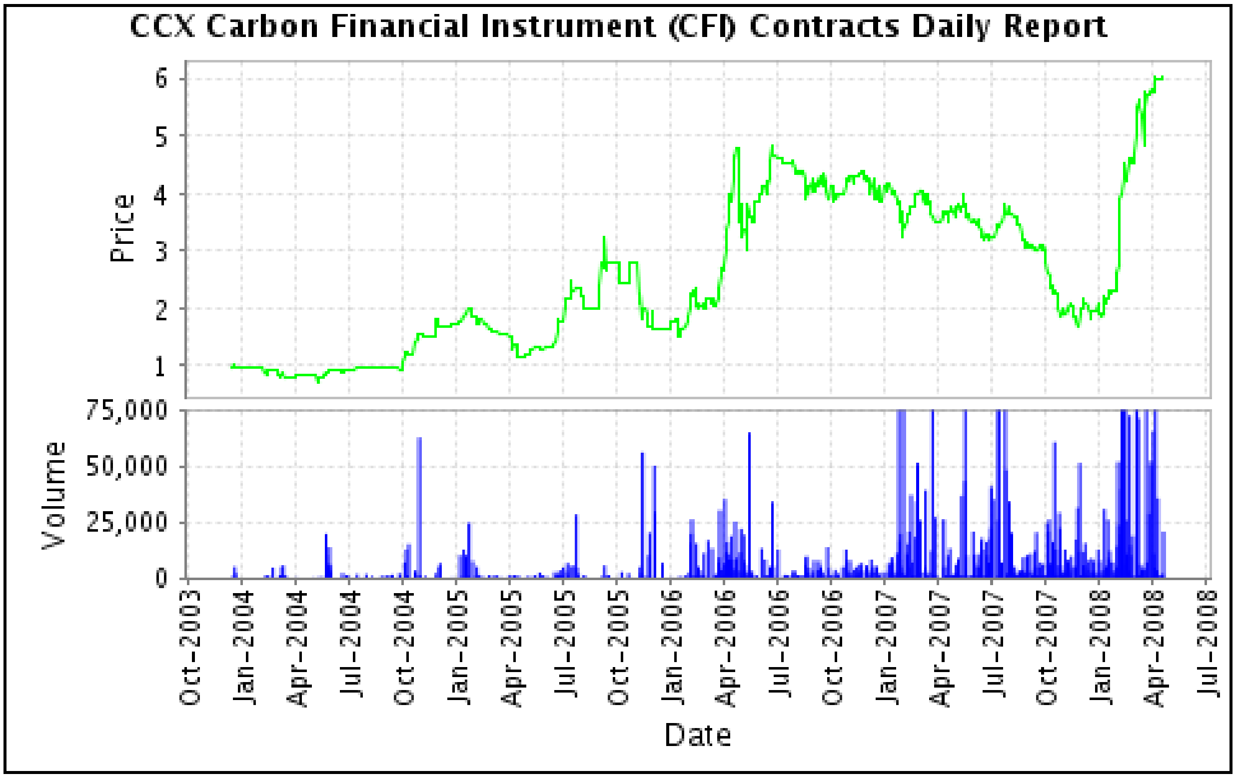
[7] Barker, T., et al., 2007: Technical Summary: In: Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, UK, and New York, NY, USA.

[8] www.vattenfall.com/climatemap (Climate map prepared by Vattenfall, the Swedish power company, with roots in hydro, which now owns power plants across Europe and promotes renewable energy and carbon reduction.), Stockholm, Sweden).

Credits are much higher in Europe, partly because it has a has a mandatory cap and trade system, where governments require industries to reduce carbon emissions.

Figure 1 shows CCX Carbon Credit prices and volume of contracts traded, over the past four years, as of April 18, 2008.

Figure 1 - Carbon Credit Prices at the Chicago Climate Exchange, Oct 2003 - Apr 2008



Reference: graph taken from http://www.chicagoclimatex.com/market/data/summary.jsf; April 20, 2008.

Carbon credit data are summarized in Tables 12 and 13. The methane reduction and renewable energy production used in computing the credit were estimated using CCX Agricultural Methane Gas Project Guidelines[9] and with data from the California Climate Action Registry livestock protocols.[10]

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[9] CCX Agricultural Methane Gas Project Guidelines, Chicago Climate Exchange, Chicago IL, February 14, 2008, Table B.7 (B.7 is a CCX table with Baseline GHG emissions from anaerobic lagoon manure management, by animal type and by state. See http://www.chicagoclimatex.com/docs/offsets/Agriculture_Methane_Protocol.pdf)

[10] Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, prepared by Economics Subgroup, Climate Action Team, Oct 15, 2007. (For CO2 offset from renewable energy, see pages 10-13 of http://www.climatechange.ca.gov/events/2007-09-14_workshop/final_report/2007-10-15_MACROECONOMIC_ANALYSIS.PDF)

Table 12 – Carbon Credits at \$3.00/ Metric Ton CO_2 for On-Site Power Generation

Dairy	Methane Reduction (CO_2 Metric Tons)	Renewable Energy (CO_2 Metric Tons)	Total (CO_2 Metric Tons)	Credit Price (\$/CO_2 MT)[1]	Total Credit Value (start-year \$)
Hilarides	17,237	1,059	18,296	\$3.00	\$54,900
Cottonwood	10,128	668	10,795	\$3.00	\$31,765
Blakes Landing	1,355	79	1,434	\$3.00	\$4,216
Castelanelli	7,892	355	8,247	\$3.00	\$24,216
Koetsier	9,957	595	10,552	\$3.00	\$31,700
Van Ommering	4,978	297	5,276	\$3.00	\$15,800
Meadowbrook	6,693	344	7,038	\$3.00	\$20,686
IEUA	35,262	2,370	37,632	\$3.00	\$112,900
Eden-Vale	6,893	412	7,305	\$3.00	\$21,900

1 *The Carbon Credit price is assumed to be \$3.00 per Metric Ton of Carbon Dioxide equivalent escalating at inflation less one half percent (2.50% - 0.50%), which is 2.00% here. Credits for plants starting in 2005 were reduced by one year's escalation of 2.00%.*

Table 13 – Carbon Credits at \$3.00/ Metric Ton CO_2 for Pipeline-Quality Gas[1]

Dairy	Methane Reduction (CO2 Metric Tons)	Renewable Energy (CO2 Metric Tons)	Total (CO2 Metric Tons)	Credit Price (\$/CO2 MT)[1]	Total Credit Value (start-year \$)
Hilarides	17,237	1,724	18,961	\$3.00	\$56,900
Cottonwood	10,128	1,013	11,141	\$3.00	\$32,745
Blakes Landing	1,355	136	1,491	\$3.00	\$4,412
Castelanelli	7,892	789	8,681	\$3.00	\$25,490
Koetsier	9,957	996	10,953	\$3.00	\$32,900
Van Ommering	4,978	498	5,476	\$3.00	\$16,400
Meadowbrook	6,693	670	7,363	\$3.00	\$21,667
IEUA	35,262	3,527	38,789	\$3.00	\$116,400
Eden-Vale	6,893	690	7,583	\$3.00	\$22,700

1 *Gas is assumed to be converted to electricity more efficiently at the utility. The carbon credit is assumed to be passed back to the dairy farmer or the effects of the carbon credit, such that price is lowered.*

2 *The Carbon Credit price is assumed to be \$3.00 per Metric Ton of Carbon Dioxide equivalent, escalating at inflation less one half percent (2.50% - 0.50%), which is 2.00% here. Credits for plants starting in 2005 were reduced by one year's escalation of 2.00%.*

In addition to selling carbon credits, another possible benefit the farmer may employ is utilizing tax credits. Section 45 of the Federal Tax Code provides for a renewable electricity Production Tax Credit (PTC). For plants placed in service after August 8, 2005, the date of enactment of the Energy Policy Act of 2005, those plants accepting agricultural livestock waste nutrients as fuel feedstock, that produce electricity, and that are sized at 150 kW or more, are classed as open-loop biomass and are eligible to receive the PTC for ten years. All PTCs are inflation-adjusted and the open-loop biomass PTC increased to 1.0 cents per kWh in 2007. Interestingly, when introduced in 2004, the credit for biomass was five years, so open-loop biomass plants placed in service before January 1, 2005, receive only a 5-year credit. Furthermore, to date (April 2008), possible expiration looms, because the PTC applies only to plants built before January 1, 2009. Proponents are hopeful the credit will otherwise be extended as it has been several times previously.

Finally, for three plants, 50% bonus depreciation was added. Bonus depreciation now permits up to half of the capital cost to be expensed in the first year. Enacted to spur development of projects undertaken from September 2001 through 2004, bonus depreciation expired, as of January 1, 2005, for most categories of equipment. For 2008, 50% Bonus Depreciation was revived as part of the 2008 Economic Stimulus Act, for plant and equipment purchased and placed in service through December 31, 2008.

Because of concerns over loss of tax revenues, several states including California, "decoupled" from the federal government regarding bonus depreciation, so their state depreciation write-offs are slower and their state taxes are slightly higher. Because it does not allow the state depreciation schedule to be different than that of the federal government, the cash flow model employed here shows the state also allowing 50% bonus depreciation. Therefore, the LCOE calculated here is slightly lower than the actual case.

Otherwise, for this analysis, assumptions closely follow those for the No Subsidy Power and No Subsidy Pipeline-Quality Gas options and are not repeated here. Economic and financial assumptions remain the same as for those No Subsidy cases.

Results and Discussion

Summary LCOE results for the No Subsidy Power projects are shown in Table 14, including without subsidies, with carbon credits only, and with carbon credits and PTC combined. The reduction from carbon credits varies from $0.017 to $0.024 per kWh, and approximately 5 to 18%. When the Section 45 PTC can be taken, it reduces LCOE by another approximately $0.015 per kWh, or about 4 to 15%.

Table 14 – No Subsidy Power LCOE (nominal levelized 2007$) with Carbon Credit and PTC

Dairy Name	No Subsidy Power LCOE – 17% IRR (¢/kWh)	LCOE for 17% IRR with carbon credit (¢/kWh)	Decrease in COE from Carbon Credit	LCOE for 17% IRR with carbon credit and PTC (¢/kWh)	Additional Decrease in COE from PTC
Hilarides	10.16	8.32	18%	6.80	15%
Eden-Vale[1]	17.63	15.79	10%	14.25	9%
Koetsier[1]	20.40	18.55	9%	17.02	8%
Castelanelli Bros.	22.69	20.28	11%	18.70	7%
Van Ommering[1]	26.14	24.19	7%	n/a[2]	
Meadowbrook	27.63	25.43	8%	23.95	5%
IEUA	34.34	32.60	5%	n/a[3]	
Cottonwood	35.46	33.73	5%	32.25	4%
Blakes Landing	37.19	35.20	5%	n/a[2]	

1 Eden-Vale, Koetsier, and Van Ommering were adjusted to employ an improved 83.45% plant capacity factor and a heat rate reduced to 13,500 Btu/kWh.

2 Engines must be sized at 150 kW or greater to be eligible for Section 45 PTC.

3 IEUA is tax-exempt and cannot take the Section 45 PTC. It might be eligible for the Renewable Energy Production Incentive payment, but would need to apply.

Table 15 shows the effects of carbon credits on LCOEs for the pipeline-quality gas projects. Plants producing pipeline-quality gas cannot take the PTC because it is available only to renewable electricity producers. The reduction in LCOE varies from $0.188 to $0.204 per therm (about 4% to 15%), with less for Blakes Landing because of the expensive pipeline required to deliver gas to the utility.

Table 15 - No Subsidy Pipeline-Quality Gas LCOE (nominal levelized 2007$) with Carbon Credit[1, 2]

Dairy Name	No Subsidy Gas LCOE, with 17% IRR ($/therm)	COE for 17% IRR with carbon credit ($/therm)	Decrease in COE (percent)
Hilarides	1.245	1.056	15%
Eden-Vale	2.812	2.624	7%
Koetsier	2.923	2.729	7%
Meadowbrook	3.226	3.033	6%
IEUA	4.004	3.806	5%
Van Ommering	4.025	3.827	5%
Castelanelli Bros. (~5 mile pipeline)	4.233	4.029	5%
Cottonwood	4.801	4.608	4%
Blakes Landing (~12 mile pipeline)	34.400	34.239	0%

1 For pipeline-quality gas, all plants operate with a plant capacity factor of 90.0%.

2 Plant must produce electricity to be eligible for Section 45 PTC.

One additional sensitivity was analyzed, specifically use of an accelerated 50% Bonus Depreciation schedule (whereby 50% of the project value is expensed in the first year).

This analysis was completed for three dairy digester projects, reflecting a high-low range, both for Power and for Pipeline-Quality Gas. Summary results are shown in Tables 16 and 17 for power and pipeline-quality gas, respectively. The tables list the No Subsidy values for reference.

In Table 16, Hilarides bounds the lower end of the LCOE range and also experiences the largest impact from carbon credits, PTC, and Bonus Depreciation with a at 37% decrease. Even if the state tax schedule were decoupled and only federal depreciation and taxes reflected 50% bonus depreciation, the LCOE would be competitive with market rates. The other projects in the table are not competitive, with or without subsidies.

Table 16 – No Subsidy Power LCOE (nominal levelized 2007$) with Carbon Credit, PTC, and 50% Bonus Depreciation

Dairy Name	No Subsidy Power LCOE – 17% IRR (¢/kWh)	LCOE for 17% IRR with carbon credit (¢/kWh)	LCOE for 17% IRR with carbon credit and PTC (¢/kWh)	LCOE for 17% IRR with carbon credit, PTC, and 50% Bonus Deprec (¢/kWh)	Total Decrease in LCOE From All Subsidies (%)
Hilarides	10.16	8.32	6.80	6.36	37%
Cottonwood	35.46	33.73	32.25	30.79	13%
Meadowbrook	27.63	25.43	23.95	22.80	17%

Table 17 - No Subsidy Pipeline-Quality Gas LCOE (nominal levelized 2007$) with Carbon Credit and 50% Bonus Depreciation[1, 2]

Dairy Name	No Subsidy Gas LCOE, with 17% IRR ($/therm)	LCOE for 17% IRR with carbon credit ($/therm)	LCOE for 17% IRR with carbon credit and 50% Bonus Deprec ($/therm)	Total Decrease in LCOE (%)
Hilarides	1.245	1.056	0.995	20%
Cottonwood	4.801	4.608	4.415	8%
Meadowbrook	3.226	3.033	2.883	11%

1 *For pipeline-quality gas, all plants operate with a plant capacity factor of 90.0%.*

2 *Plant must produce electricity to be eligible for Section 45 PTC.*

Table 17 shows that the total decrease in LCOE from the combination of carbon credits and 50% bonus depreciation ranges from 8% to 20%.

4.6. Recent Favorable Utility Rate Structures

Standard Offer Contracts

Dairy digester power and pipeline-quality gas plants may be characterized as a high capital cost, low operating expense technology. That is, the fixed or capital component of

LCOE tends to be high, while the variable or operating expense component is much lower. To improve its levelized costs of energy, which means to reduce the power price charged to customers, the dairy digester plants need to operate long hours, making for a high plant capacity factor, so as to spread their high fixed costs over a larger amount of energy sales. As discussed with Actual Cases, under Section 3.3 and Section 4.1, because net metering credits sometimes were forfeited and because prices were low, some farmers flared biogas, deliberately turned down their engine-generators and operated at capacity factors as low as 20% to 45%. If higher power purchase rates were available, farmers could be expected to operate at higher plant capacity factors and to stop flaring gas, improving the overall heat rate.

During the WURD study period of June 2004 through July 2006, options for selling power were principally that the farmer connected on-farm electric loads and displaced purchases at a retail rate and exhanged power under a net metering agreement with the utility for a wholesale rate. As discussed, despite meeting on-farm load with the dairy power plant, several farmers continued to pay demand charges, so they saved only the energy portion of the retail rate. Net metering credits were forfeited if the farmer did not use enough power within 12 months to off-set excess energy delivery to the utility.

Beginning in 2007, the utilities are offering dairy farmers more favorable terms. Since May 2007, Southern California Edison (SCE) has offered a Biomass Standard Contract for plants under 1 MW, so they may sell energy and as-delivered capacity for one all-in rate, now over 9 cents/kWh, that holds flat for the years of the contract. The rate varies depending on plant start-up date and whether the contract is for 10, 15, or 20 years. This schedule matches the California Market Price Referent (MPR) rate, representing the long-term levelized price in nominal dollars of a combined cycle natural gas plant. When utilities sign power purchase contracts, especially after issuing an RPS solicitation, prices at or below the MPR are considered reasonable by the California PUC. SCE offered these contracts through December 31, 2007, which was extended to be through December 31, 2008, or until 250 MW is signed, whichever comes first. Projects must come on line within 5 years of the deadline. One attractive feature is that because SCE's contract is for as-delivered capacity and not firm capacity, there is no penalty for modest plant outages.

Pacific Gas and Electric (PG&E) offers a similar contract. For PG&E, which announced its program in early September 2007, plants may be sized to 1.5 MW, contracts are available until 104 MW from renewables and 104 MW from Water Agencies are signed, and projects have 18 months to be built and start-up (not 5 years). One attractive feature is that PG&E allows the project owner to sell all output from the plant (full buy/sell) or to sell only excess power, after on-site use by the seller (excess sale).

The adopted 2007 Market Price Referents, passed by the CPUC with Resolution E-4118 and effective October 4, 2007, are as shown in Table 18. This MPR schedule is cited in Standard Contracts by both SCE and PG&E, except SCE's contract lists years only through 2016. The MPR rate indicated holds flat for the term of the contract and does not escalate.

Table 18 – Adopted 2007 Market Price Referents (nominal dollars per kWh)

Resource Type	10-year	15-year	20-year
2008 Baseload MPR	0.09271	0.09383	0.09572
2009 Baseload MPR	0.09302	0.09475	0.09696
2010 Baseload MPR	0.09357	0.09591	0.09840
2011 Baseload MPR	0.09412	0.09696	0.09969
2012 Baseload MPR	0.09518	0.09844	0.10139
2013 Baseload MPR	0.09605	0.09965	0.10275
2014 Baseload MPR	0.09722	0.10107	0.10430
2015 Baseload MPR	0.09872	0.10274	0.10606
2016 Baseload MPR	0.10053	0.10466	0.10804
2017 Baseload MPR	0.10269	0.10685	0.11143
2018 Baseload MPR	0.10478	0.11016	0.11489
2019 Baseload MPR	0.10818	0.11370	0.11720
2020 Baseload MPR	0.11172	0.11603	0.11954

As an overlay to the MPR schedule, both PG&E and SCE offer a time-of-delivery (TOD) option where, if the dairy installs time-of-day metering, it may opt to sell time-of-delivery power, to receive a higher-than-average rate during peak periods and lower-than-average during off-peak periods. During the best pricing periods during summer peak demand hours (e.g., noon through 6:00 pm on weekdays from June through September except holidays), the utilities pay 2 to 3 times the average rate. To take maximum advantage, obviously, the generator sells as much power as possible during peak periods and schedules plant shut-down and repairs for night and other off-peak periods. It is noted that PG&E's time of delivery periods, classification categories, and payments vary slightly from those of SCE. Utility tariffs and contract conditions should be carefully reviewed by legal counsel before entering into contracts.

San Diego Gas and Electric (SDG&E) is California's southern utility. Because it is smaller, and there are fewer dairy farms in its territory, SDG&E does not offer a specific Standard Contract for projects sized under 1 MW. Minimum project size is 1.5 MW for certain projects and 5 MW for others. However, a representative of SDG&E, interviewed for this report in April 2008, said that dairy farmers with digester power plants should come to talk to SDG&E to try to work out mutually agreeable terms, on a custom basis.

Feed-In Tariffs

In other recent developments, on February 20, 2008, in implementing California Assembly Bill 1969 (2006) to increase renewable energy use and reduce greenhouse gas emissions, the CPUC formalized its approval of the Standard Offer Contracts described above. Furthermore, the CPUC established a standard tariff, also termed a Feed-in Tariff

(FIT), to be paid by utilities purchasing power from customers. The FIT is determined by the Market Price Referent and TOD schedules.

For SCE, PG&E, and SDG&E, as well as for PacifiCorp, Sierra Pacific Power, Bear Valley Electric Service, and Mountain Utilities, the FIT applies to public water and wastewater facilities selling power from renewable energy plants, but for SCE and PG&E, it applies also to retail customers selling power from small systems up to 1.5 MW (utilizing renewable energy or fossil fuel), who do not utilize other state incentive programs. The CPUC published sample rates as reproduced in Table 19.

Table 19 – Sample Time Dependent Prices, under a 15-year Contract starting in 2008

	Summer Week-day ($/kWh)			Winter Week-day ($/kWh)		
Utility	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
PG&E	0.18	0.08	0.06	0.14	0.10	0.07
SCE	0.31	0.12	0.06	0.10	0.08	0.06
SDG&E	0.15	0.10	0.08	0.11	0.10	0.07

CPUC Resolution E-4137, February 14, 2008.

5.0. Conclusions

Actual Cases: Analysis of the Actual Cases showed that LCOEs tended to be low, but IRRs varied widely. All but one of nine actual projects installed under the California Energy Commission's Dairy Power Production Program (DPPP) and receiving grants or production payment incentives had a levelized cost of energy (LCOE) under $0.10/kWh (in nominal 2007 dollars) using the cost and performance data from the 2006 WURD report. However, the farmers signed net metering agreements with the local utility, took the rates that were offered, and only five of those plants showed attractive returns, ranging from 4% to 23%, as measured by after-tax IRR.

Three of the nine had LCOE below $0.07/kWh, but they showed IRRs at break-even, for one plant, and at about -13% to -14%, for two others. One plant had LCOE of $0.098/kWh, but its IRR was about -14%. Farmers who received too low a power purchase price did not run their plants in optimal fashion, but flared gas and deliberately turned down their engines to operate below rated capacity.

Results of this portion of the economic study show that with grant assistance, the three best returns belong to Hilarides, with an after-tax IRR at 22.82%, Castelanelli at 21.27%, and Blakes Landing at 19.02%. The three next best are Cottonwood at 8.64%, Meadowbrook at 4.76%, and Van Ommering at -0.12%, which is about break-even. However, the remaining three returns are negative, including Koetsier at -13.25%, IEUA at -13.78%, and Eden-Vale at -13.97%.

Large variations in IRR are due to the different amount of grants received; prices paid for electricity sold to utilities (with some dairies not receiving capacity payments and/or still required to pay utility demand charges); capital cost of plant and equipment, operating efficiency, and O&M costs. For example, Hilarides received a "buy-down" grant for 40% of capital cost. They held initial capital cost low at $2,480/kW by using refurbished equipment, while other farms spent at least double that figure. As another example, Blakes Landing operated with only a 38.48% plant capacity factor and realized a capital cost of $4,504/kW, but they sold most of their electricity during peak periods, at attractive prices of $0.1509/kWh retail and $0.1257/kWh wholesale (nominal levelized 2007$), which offset their higher costs.

No Subsidy Power: All of the DPPP projects were subsidized with grants or production payment incentives. If grants and subsidies are removed, the LCOEs are higher, and are no longer near the competitive range for AD power or gas projects.

However, it is critical to note that for the "No Subsidy" power cases, the AD digester system and the engine-generator were assumed to operate under the same estimates of capital cost, performance, and operating expense as for the "Actual" cases. The exception was that three plants with low plant capacity factors were adjusted upward, which reduced their LCOEs, but not sufficiently to reach market rates, as measured by the market price referent (MPR), without peaking adjustments.

Consequently, beyond the farmer's running the existing plant longer, which manifests in an improved plant capacity factor, the broad conclusion is the need to improve plant design, reduce plant and equipment capital costs, and improve performance.

Specifically, to lower capital costs, increase plant performance, and reduce operating and maintenance expenses, both equipment and overall plant design could be standardized to a larger degree, and then optimized for each application. This holds for manure handling systems and other feedstock logistics, digesters , effluent handling, liquid storage, gas processing and cleaning, emission controls, and the engine-generator system. Heat recovery equipment can further improve efficiency.

In league with design, field testing and operational experience are important to improving the cost and performance of the technology. For example, improved gas clean-up equipment should be installed to reduce the need to frequently rebuild engines and replace lubricating oil. With more performance and operation data available, financial projections will be more accurate, aiding the farmer/owner and any investors.

No Subsidy Pipeline-Quality Gas: The pipeline-quality gas systems were generally costly, due to the cost of gas clean-up and upgrading. Without grants or other subsidy, production of pipeline-quality gas is not economically feasible due to the small volume of biogas produced (less then 500 Mcf/day). When the farm is far from a utility pipeline, cost increases significantly because of the cost to build a connecting pipeline.

Enhanced Environmental Quality: For enhanced environmental quality cases producing power, levelized costs of energy would be increased over those for no subsidy power by about 5% to 25% for most of the DPPP plants, with one exception at 83% and another at 1%. For enhanced environmental quality cases producing pipeline-quality gas, levelized costs of energy are increased by slightly smaller percentages, but the base prices for no subsidy pipeline-quality gas are sufficiently high that the smaller increase is still problematic.

As discussed above, before or concurrent with development of the enhanced environmental quality systems, greater standardization of design is encouraged. Otherwise, No Subsidy Power LCOE's are high and those for Enhanced Environmental Quality Power are higher yet. No Subsidy Pipeline-Quality Gas LCOE's mostly are not economically feasible against current natural gas tariffs, nor are the Enhanced Environmental Quality Pipeline-Quality Gas systems under these projections.

Summary: For the near term, it would appear that, while equipment becomes more standardized and further field experience is gained, grants or other subsidy mechanisms are still needed for most systems to encourage future development, that is, to give the farmer/owner a sufficiently attractive return to undertake the project. There is an obvious need to reduce capital costs on average, and the wide range in costs clearly demonstrates the potential for improvement in this category.

The two obvious ways for AD projects to maximize the rate paid for their electrical energy are to use a large fraction of power on site, because retail rates are higher than wholesale, and to maximize sales during peak periods, the latter assuming the process is in place to meter and bill under time-of-delivery. In addition to maximizing the rate paid for sales of power, there are other potential sources of additional revenues and subsidies outside of participation in the DPPP that can improve project economics including carbon credits, Section 45 production tax credits (PTC), and possible sale of byproducts.

The sensitivity analysis conducted in this report showed that under special circumstances where initial capital cost is reduced below current market price levels, a biogas power system can be economically feasible

Specifically, without grant assistance, the No Subsidy Hilarides dairy power project achieved a levelized cost of energy of 6.80 cents/kWh (in nominal 2007 dollars), with the following set of conditions:

- Plant size of 500 kW;
- capital cost of $2,643/kW, partly achieved by using refurbished equipment;
- plant capacity factor of 77%;
- carbon credit at $3/MT CO_2 equivalent; and
- Section 45 PTC of $0.01/kWh.

With 50% Bonus Depreciation, the LCOE declines further to 6.36 cents/kWh.

6.0. Recommendations

Results of this study show that further research and field operating experience with AD biogas systems at dairy farms is needed to reduce capital costs and operating expenses, and to improve efficiency to the point where projects are more economically attractive. Research and greater operating experience are needed regarding:

- feedstock logistics, to reduce costs of handling;
- the digester system, to optimize gas production;
- the engine-generator, to increase operating time, net power production, and reduce emissions;
- the pollution control system to meet air and water quality standards;
- the gas clean-up equipment to extend equipment life and provide greater flexibility in engine exhaust after-treatment, to reduce air emissions from power generation, and to improve gas upgrading for pipeline injection; and
- heat recovery equipment to further improve overall project efficiency.

The economics of above-ground reactors should be examined. Grants or other subsidies are still needed to promote development to gain field experience and benefit waste management.

Greater collaboration is required among dairy operators, utilities, permitting agencies, and funding and financing authorities to ensure an attractive price is paid that encourages efficient plant operation. This involves resolving existing issues on net metering, such as paying the farmer both energy and demand charges for excess energy delivered, setting reasonable stand-by demand charges consistent with well operated, high capacity factor systems, and reducing or eliminating forfeiture of net metering credits.

Alternatively, it involves developing attractive power purchase agreements for small power projects to buy all output or excess energy (above the seller's on-site use) at attractive long-term rates. One attractive feature of SCE's Small Biomass Standard Contract, for example, is that the utility will buy "as-delivered capacity" and not "firm capacity," so there is no penalty for modest plant outages.

The new feed-in tariffs offer a means to buy power that may prove attractive. But there is concern that low off-peak rates result in average electricity prices that are typically insufficient to justify base-load operation. The long term contracting requirements create uncertainty for some when weighing choices between feed-in tariffs and net metering.

Additional research and analysis should be conducted to assess the potential benefits from codigesting additional feedstocks with manure. For example, additional volume to the plant may be achieved by augmenting with another waste stream, such as food or food processing waste, e.g. from a nearby cheese plant. A significant boost to revenues might be achieved. Further, additional revenues from sales of co-products from the AD process, e.g., fertilizer, livestock bedding material, should be evaluated for their impact on LCOE.

Most current plants are all equity financed, so there may be opportunities for aggregators or other developers to build larger anaerobic digester facilities. Such facilities would include economies of scale in equipment purchase, installation, and operation and might be financed using non-recourse project finance including debt, which would improve economics. However, because manure management is integral to operation of the dairy farm, some farmers will want to maintain control and will continue to finance using all equity. A possible hybrid approach could be to aggregate equipment purchases and certain project design development and maintenance services to lower costs through standardization and bulk purchase discounts.

Regarding prices, some critics worry that a 20-year nominal flat price encouraged by MPR will be greatly under market prices near the end of its term if inflation were to increase. They would argue for a year one bid price that starts lower, but is accompanied by an annual escalator moving with some widely-accepted economic index (e.g., PPI, the Producer Price Index). This is unlike the approach adopted with Standard Offer Number Four (SO4) contracts in the past because the first ten years of the contract would not be fixed in advance based on today's estimate of inflation. Rather, rates would "float" with the index, changing every year. At today's forecast of inflation, the bid price and escalator would be equivalent to MPR. But should inflation rise, the power producer would receive "fair" market prices, and would not receive such low prices that he or she abandons the project or, in the case of a farmer, where the dairy digester is a key component to farming, operates at a very low plant capacity factor. This is equivalent to suggesting the MPR be indexed.

At the same time, Feed-in tariffs may be combined with efforts to run the plant as a peaking operation. Some means of gas storage must be developed, perhaps in combination with over-sizing the plant, by connecting several modular units that provide back-up or by employing one or two larger units that are more cost-effective. The farmer runs the plant to sell mostly peak and partial-peak power.

Lastly, as farmers seek to build more projects, state environmental and other agencies might conduct outreach through meetings, written materials, and web-site information. Agencies might explain what materials and information are needed to obtain permits, such that farmers and their engineers could provide them quicker and with less revision.

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APPENDIX A – Assumptions, Inputs, and Results

Table A- 1 Financial and Economic Assumptions

	Feature	Actual Dairy Power	No Subsidy Dairy Power
1	Lifetime	20 years	Same
2	Inflation	2.50%	Same
3	Start Year and year 1 fraction	Varies by Dairy, as first full year after startup. Year 1 fraction is 100%.	Same
4	Construction Period (years)	1 year, with capital costs expressed in "year before start-year" dollars.	Same
5	Basic Structure of Plant	All equity, on-balance sheet financing. There is no debt.	Same
6	Basic Structure of Power Sales Options	NemBio, Net Energy Metering for BioGas Customer-Generators, available from California utilities.	100% sales to the utility, at one flat rate that does not escalate, which is similar to MPR.
7	Capitalization	0% Debt. Some fraction Grant (from DPPP, US EPA, or other). Remaining balance fraction Equity.	0% Debt to 0% Grant to 100% Equity. No incentive payments are assumed.
8	Debt Rate	Moot here.	Same
9	Debt Term	Might be 10 to 15 years for a 20-year project. However, debt is moot here.	Same
10	Debt Rating	n/a	n/a
11	Project Development Load	For the actual cases, no costs, expenses, or reserves were reported, so zero.	Typical development expenses were assumed, as: Construction financing at 8.0% of plant cost by 1 year by 50% for level draw; Financing fees at 1.50% of debt (moot here with no debt) and 1.50% of equity (for tax advice, legal & accounting fees, misc.); and Working Capital reserve at 1.0% of plant cost. Assume construction financing is a loan, so capitalized interest is depreciable, and that financing fees are amortized.
12	Property Tax and Insurance	For the actual cases, property tax and insurance were not reported, so they are treated as zero. Probably, property tax and insurance for the dairy digester systems were included with property tax and insurance for the farm operation as a whole.	Assume property tax is 1.0% of depreciable base, with assessment escalating at 2.0% per year in California, and with wear-and-tear on equipment estimated as 4.0% per year till it hits a limit of 30% and falls no further. Assume insurance is 0.6% of depreciable base, escalating by 2.50% inflation, to obtain replacement value.

	Feature	Actual Dairy Power	No Subsidy Dairy Power
13	After-tax Leveraged Equity Return	Varies by dairy power plant.	Assumed 17% minimum taxable return was required by the farmer in order to undertake the project or 11% for tax-free entities. Since projects were financed 100% equity (see #7), this makes for a 17% or 11% return on capital.
14	Tax Rate	40.75% combined. Calculated as (0.35 + 0.0884 * 0.65 = 0.4075), assuming maximum California corporate rate. For tax-free entities like IEUA, the income tax rate is zero.	Same, as 40.75% taxable and 0.00% for tax-free IEUA.
15	Debt Coverage: operating income over debt payment (interest + principal)	Here, debt coverage is moot.	Same
16	Revenues: Fraction from various products or class of purchaser	The nine dairy power plants took varying fractions of power to meet on-farm retail power loads, and sold the balance to the utility wholesale for net metering credits. Note that for this analysis, no net metering credits were assumed to be forfeited, but were all sold to the utility. (This is a more favorable assumption than really existed.) For actual cases, the fraction of energy employed for steam or heat savings was estimated. Any byproduct sales of carbon credits or other were estimated.	For “No subsidy” power cases, assume zero retail sales to the farm and 100% wholesale sales to the utility. In real life, the farmer probably would expand his plant to 500 kW, say, would keep 200 kW for his own use probably avoiding standby demand payments, and would sell 300 kW. However, for this analysis, since one does not know expansion capabilities, assume 100% sales to the utility.
17	Electricity Revenues and Revenue Escalation Rate.	Under NemBio, there are two rates, on-farm offset and utility net metering sales, where an energy price is paid. These rates vary by dairy. Regarding escalation, assume both on-farm offset and utility net metering energy prices escalate with 2.50% inflation. Assume demand prices escalate 1%, but since there are no demand payments reported for the actual cases, this is moot.	For “No Subsidy” power cases, assume one flat all-in rate that does not change. Therefore, assume one starting point and that escalation is 0%.
18	Section 45 Production Tax Credit	Not reported by any of the dairy power plants.	Only power sold to the utility, from plants sized over 150 kW, is eligible. For PTC sensitivity cases, assume \$0.01/kWh in 2007 (adjusted downward for proper starting year), escalating by inflation, for 10 years.
19	IOU Cost of Capital Discount Rate by which to calculate COE	Rate is 8.50% nominal, as an estimate of a taxable utility’s before-tax cost of capital. Assume 50% debt @ 6.50, 5% preferred stock @ 6.30, and 45% common stock at 11 = 8.52%. Rate is 5.854% constant (1.085 / 1.025 inflation - 1).	Same

	Feature	Actual Dairy Power	No Subsidy Dairy Power
		A typical IOU rate is employed as the discount rate for standardization. The taxable utility's discount rate is employed for all farmer projects and also for that of tax-free IEUA, so that results may be compared. If each project used the discount rate of its developer/owner, rates would be different for each project. To compare apples to apples, it is desirable that one rate be employed. Further, the utility is the back-up source of power.	
20	Depreciation	5-year MACRS, using the half-year convention. (MACRS, pronounced "makers," is the Modified Accelerated Cost Recovery System.) Cattle breeding and dairy farms take 5-year depreciation. Tax counsel must be consulted.	Same
21	Amortization	Debt fees are amortized straight line over life of debt. Equity fees are part tax advice (expensed in 1 year) and part organization fees (amortized straight-line over 5 years), and part other (no write-off or amortized over the life of the project). However, there are no debt or equity fees for actual cases here.	For no subsidy case, assume equity fees, at 1.50% of equity, are 40% tax advice and 60% not written off.
22	Positive Before-Tax Cash Flow	All before-tax cash flow is positive, except when there are operating losses, which happens rarely.	Because rates are raised high enough to give the farmer a 17% (or 11%) return, all before-tax cash flow is positive.

Table A- 2 Detailed Data Inputs for Nine Dairy Farm Digester Systems

Blakes Landing Farms

Data Inputs for Blakes Landing Farms
Introduction and Capital Costs

		Component	Blakes Landing Farms actual ($)	Blakes Landing Farms no subsidy power ($)	Blakes Landing Farms no subsidy pipeline-quality gas ($)
	Introduction				
		Digester System Type	Covered Lagoon	Covered Lagoon	Covered Lagoon
		Generator Nameplate Capacity (kW)	75 kW	75 kW	--
		First Full Start Year	2005	2005	2005
		Total Lactating Cows	245	245	245
		Total Herd	447	447	447
		Farm Size (acres)	660	660	660
		Location	Marshall, Marin County, CA	Marshall, Marin County, CA	Marshall, Marin County, CA
		Utility	PG&E	PG&E	PG&E
		Digester and Generator System Design	Williams Engineering Associates	Williams Engineering Associates	Williams Engineering Associates
1	Manure Collection and Pretreatment				
	A	Lagoon	0	0	0
	B	Lagoon Liner	0	0	0
	C	Manure Collection	0	0	0
	D	Vacuum Trailer	0	0	0
	E	Solids Separator/ Grit Removal	0	0	0
	F	Collection Mix Tank	0	0	0
		Subtotal	0	0	0
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	0	0	0
	B	Lagoon Cover	0	0	0
	C	Digester Heating System	7,605	7,605	7,605
	D	Bacterial Treatment	0	0	0
		Subtotal	7,605	7,605	7,605
3	Energy Conversion and Gas Handling				
	A	Engine/generator (1 Waukesha 817G at 75 kW, that was used and refurbished, was purchased)	54,554	54,554	0
	B	Overhaul, repair, and additional components	4,109	4,109	0
	C	Engine/generator room or building	1,496	1,496	0
	D	Gas Transport	16,530	16,530	16,530
	E	Flare (flare was constructed, not purchased)	1,240	1,240	1,240
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	17,222	17,222	0
	H	Heat recovery (hot water or other)	18,589	18,589	18,589
		Subtotal	113,740	113,740	36,359
4	General Construction				
	A	Excavation, trenching, and grading	0	0	0
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	0	0	0
	D	Other contractor/subcontractor	0	0	0
	E	Dairy labor used for construction and installation	0	0	0
	F	Transportation, Fuel and Heavy Equipment Rental	0	0	0
	G	Other Equipment and Materials	0	0	0
		Subtotal	0	0	0
5	System Design/Engineering				
	A	System Design/Engineering	23,000	23,000	23,000
	B	Other			
		Subtotal	23,000	23,000	23,000
6	Permits				
	A	Permits – air	0	0	0
	B	Permits – building	0	0	0
	C	Permits – water	0	0	0
	D	Other		0	0
		Subtotal	0	0	0
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	800	800	0
	B	Interconnect Equipment req'd by utility	14,535	14,535	0
		Subtotal	15,335	15,335	0

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2005 so assume construction is 2004 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Initial Costs incurred prior to refurbishment - floating cover for lagoon in year 2000, to convert lagoon to an anaerobic digester	175,000	175,000	175,000
	B	Other Construction Costs after System Completion	3,100	3,100	3,100
	C	Tap, Controls, Unique Faclities			156,098
	D	Gas Clean-up and Processing			390,244
	E	SCADA Monitoring			87,805
	F	Pipeline from farm to gas pipeline - 12 miles for Blakes Landing			2,474,146
		Subtotal	178,100	178,100	3,286,393
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	13,500	134,100
	B	Construction Insurance			
	C	Other Overhead/Admin	0		
	D	Land	0		
		Subtotal	0	13,500	134,100
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – e.g., 1.50% for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	5,400	53,600
		Subtotal	0	5,400	53,600
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	3,400	33,500
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	3,400	33,500
12		**Total Loaded Cost**	**337,780**	**360,080**	**3,574,557**

Sources of Funds

		Component	Blake Landing Farms Actual Case	Blake Landing Farms power case with no subsidies	Blake Landing Farms pipeline-quality gas case with no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant	67,900	0	0
	4	Second Grant	87,361	0	0
	5	Equity	182,519	360,080	3,574,557
		Total	**$337,780**	**$360,080**	**$3,574,557**

Performance and Annual Operating Expenses

		Component	Blakes Landing Farms Actual Case	Blakes Landing Farms power case with no subsidies	Blake Landing Farms pipeline-quality gas case with no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power or Gas Production:**			
		Gross Rated Capacity (kW for Power;	75	75	14.832
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	75	75	12.607
	4	Capacity Wholesale to Utility (kW or Mcf/day)	0	75	12.607
		Capacity Retail to Steam Host (kW or Mcf/day)	75	0	0
	5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
		Forced Outage Hours	973.00	973.00	276.00
		Planned Outage Hours	4,416.50	4,416.50	600.00
		Hours of Operation after Outages	3,370.50	3,370.50	7,884.00
		Capacity Factor (%) after Outages	38.48%	38.48%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%

Blakes Landing Farms

	7	**Net Power or Gas Produced for Sale**	252.788	252.788	2,671.245
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail	60.25%	0.00%	0.00%
		Percent Sold Wholesale to Utility	39.75%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.059	0.000	0.000
		Full load operating hours/yr	3,370.5	3,370.5	7,884.0
		Unfired Capacity (mlb/yr)	197.216	0.000	0.000
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	12.00	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	10.00	35.40	321.00
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	$18.25	$0.00	$0.00
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	$0.00	$0.00	$0.00
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Other	0	0	0
		escalating by (%/year)	2.50%	2.50%	2.50%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	13,813	13,813	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	3,491.75	3,491.75	3,491.82
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.645	0.645	0.645
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	1.0360	1.0360	0.4429
		Fuel #2 Consumption (mm Btu/hr)	0.0000	0.0000	0.0000
		Hours/year	3,370.50	3,370.50	7,884.00
		Total Consumption (mm Btu/yr)	3,491.75	3,491.75	3,491.82
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	40,230	40,230	40,230
		Biogas Potential (mm Btu/yr)	9,471.15	9,471.15	9,471.15
			--	--	--

	23	Fuel #1 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0		
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service			
	27	Operations and Maintenance ($/year)	$3,948.00	$3,948.00	$3,948.00
	28	Consumables			
	29	Operator			
	30	Admin/Compliance			
	31	Royalty (% of revenues)			
	32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.	0	0	0
	35	Other			
	36	Other	0	0	0
	37	Gas Monitoring ($/year)	0	0	9,756
	38	Final Note: Important Facts that may help to optimize project.	For Blakes Landing, no gas is flared. Added about 20 cows. Looking to upgrade with quieter, more efficient engine or with turbine. Plans to connect more dairy load to main meter. Will repair cover leaks that allow extra air into digester and reduce power output. Wants to recover more heat. Manure solids are run through two mechanical separators and creamery wastewater is also fed to digester. This system has lowest hydrogen sulfide production, which is good.		

Castelanelli Bros. Dairy

Data Inputs for Castelanelli Bros. Dairy
Introduction and Capital Costs

		Component	Castelanelli Bros. Dairy actual ($)	Castelanelli Bros. Dairy no subsidy power ($)	Castelanelli Bros. Dairy no subsidy pipeline-quality gas ($)
	Introduction				
		Digester System Type	Covered Lagoon	Covered Lagoon	Covered Lagoon
		Generator Nameplate Capacity (kW)	160 kW	160 kW	--
		First Full Start Year	2005	2005	2005
		Total Lactating Cows	1,601	1,601	1,601
		Total Herd	3,601	3,601	3,601
		Farm Size (acres)	n/a	n/a	n/a
		Location	Lodi, San Joaquin County, CA	Lodi, San Joaquin County, CA	Lodi, San Joaquin County, CA
		Utility	PG&E	PG&E	PG&E
		Digester and Generator System Design	RCM Digesters	RCM Digesters	RCM Digesters
1	Manure Collection and Pretreatment				
	A	Lagoon	55,734	0	0
	B	Lagoon Liner			
	C	Manure Collection	41,024	41,024	41,024
	D	Vacuum Trailer			
	E	Solids Separator/ Grit Removal	63,518	63,518	63,518
	F	Collection Mix Tank	0	0	0
		Subtotal	160,276	104,542	104,542
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	0	0	0
	B	Lagoon Cover	204,768	204,768	204,768
	C	Digester Heating System	0	0	0
	D	Bacterial Treatment	0	0	0
		Subtotal	204,768	204,768	204,768
3	Energy Conversion and Gas Handling				
	A	Engine/generator (1 CAT G3406T engine-generator at 160 kW was purchased new)	124,460	124,460	0
	B	Overhaul, repair, and additional components	9,274	9,274	0
	C	Engine/generator room or building	23,668	23,668	0
	D	Gas Transport	37,524	37,524	37,524
	E	Flare (flare was constructed, not purchased)	1,799	1,799	1,799
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	8,415	8,415	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	205,140	205,140	39,323
4	General Construction				
	A	Excavation, trenching, and grading	0	0	0
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	23,210	23,210	0
	D	Other contractor/subcontractor	0	0	0
	E	Dairy labor used for construction and installation	156,568	156,568	156,568
	F	Transportation, Fuel and Heavy Equipment Rental	0	0	0
	G	Other Equipment and Materials	14,417	14,417	14,417
		Subtotal	194,195	194,195	170,985
5	System Design/Engineering				
	A	System Design/Engineering	61,595	61,595	61,595
	B	Other			
		Subtotal	61,595	61,595	61,595
6	Permits				
	A	Permits – air	0	0	0
	B	Permits – building	200	200	200
	C	Permits – water	0	0	0
	D	Other			
		Subtotal	200	200	200
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	46,524	46,524	0
	B	Interconnect Equipment req'd by utility	7,867	7,867	0
		Subtotal	54,391	54,391	0

Castelanelli Bros. Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2005 so assume construction is 2004 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Other Construction Costs after System Completion - 2006 cost to rewire and add milk barn, 3 lagoon pumps, well & separator to engine-generator to use on-site power	84,727	84,727	0
	B	Other - RCM Digesters' tax/freight	1,570	1,570	0
	C	Tap, Controls, Unique Faclities			156,098
	D	Gas Clean-up and Processing			468,293
	E	SCADA Monitoring			87,805
	F	Pipeline from farm to gas pipeline - about 5 miles for Castelanelli Bros.			1,053,659
		Subtotal	86,297	86,297	1,765,855
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	36,400	93,900
	B	Construction Insurance			
	C	Other Overhead/Admin	0		
	D	Land	0		
		Subtotal	0	36,400	93,900
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	14,600	37,500
		Subtotal	0	14,600	37,500
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	9,100	23,500
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	9,100	23,500
12		**Total Loaded Cost**	**$966,862**	**971,228**	**2,502,168**

Sources of Funds

		Component	Castelanelli Bros. Dairy Actual Case	Castelanelli Bros. Dairy power case with no subsidies	Castelanelli Bros. Dairy pipeline-quality gas case with no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant	320,000	0	0
	4	Second Grant	227,396	0	0
	5	Equity	419,466	971,228	2,502,168
		Total	**$966,862**	**$971,228**	**$2,502,168**

Performance and Annual Operating Expenses

		Component	Castelanelli Bros. Dairy Actual Case	Castelanelli Bros. Dairy power case with no subsidies	Castelanelli Bros. Dairy pipeline-quality gas case with no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	160	160	89.147
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	160	160	75.775
	4	Capacity Wholesale to Utility (kW or Mcf/day)	85	160	75.775
		Capacity Retail to Steam Host (kW or Mcf/day)	75	0	(0.000)

	5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
		Forced Outage Hours	204.00	204.00	276.00
		Planned Outage Hours	1,460.00	1,460.00	600.00
		Hours of Operation after Outages	7,096.00	7,096.00	7,884.00
		Capacity Factor (%) after Outages	81.00%	81.00%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0		0
	7	**Net Power or Gas Produced for Sale**	1,135.360	1,135.360	15,557.544
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail	49.96%	0.00%	0.00%
		Percent Sold Wholesale to Utility	50.04%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.000	0.000	0.000
		Full load operating hours	7,096.0	7,096.0	7,884.0
		Unfired Capacity (mlb/yr)	0.000	0.000	0.000
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	7.240	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	5.76	21.60	39.50
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Other	0	0	0
		escalating by (%/year)	2.50%	2.50%	2.50%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	17,912	17,912	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	20,336.57	20,336.57	20,336.67
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.625	0.625	0.625
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	2.866	2.866	2.579
		Fuel #2 Consumption (mm Btu/hr)	0.000	0.000	0.000
		Hours/year	7,096.00	7,096.00	7,884.00
		Total Consumption (mm Btu/yr)	20,336.57	20,336.57	20,336.67
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	324,090	324,090	324,090
		Biogas Potential (mm Btu/yr)	73,933.03	73,933.03	73,933.03
			--	--	--

	23	Fuel #1 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0	0	0
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service			
	27	Operations and Maintenance	$11,400.00	$11,400.00	$11,400.00
	28	Consumables			
	29	Operator			
	30	Admin/Compliance			
	31	Royalty (% of revenues)			
	32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.	0		
	35	Other			
	36	Other Costs - Engine Rebuild at 6,500 hrs. Assume this is annual expense, that escalates with inflation.	$3,000	$3,000	$0
	37	Gas Monitoring ($/year)	0	0	9,756
	38	Final Note: Important Facts that may help to optimize project.	Castelanelli Bros. Dairy flares about 40% to 50% of gas. Plant was not run at capacity because no place to sell power. In 2006 (after 12-mo study period of Oct 2004-Sept 2005), the farmer rewired more dairy load to utilize more of the engine-generator's power. Added milk barn, 3 lagoon pumps, well and separator at cost of $84,727, as cited above. Data on savings? It was assumed this reduced generation credits that were forfeited and that rates increased to 7.242 and 5.76 cents/kWh, for on-farm off-set and net generation respectively. Will plant run more? Will this dairy expand further? Experimental biological scrubber seemed to test well here (to remove hydrogen sulfide).		

Cottonwood Dairy

Data Inputs for Cottonwood Dairy
Introduction and Capital Costs

		Component	Cottonwood Dairy actual ($)	Cottonwood Dairy no subsidy power ($)	Cottonwood Dairy no subsidy pipeline-quality gas ($)
	Introduction				
		Digester System Type	Covered Lagoon	Covered Lagoon	Covered Lagoon
		Generator Nameplate Capacity (kW)	300 kW	300 kW	--
		First Full Start Year	2005	2005	2005
		Total Lactating Cows	4,971	4,971	4,971
		Total Herd	5,616	5,616	5,616
		Farm Size (acres)	n/a	n/a	n/a
		Location	Atwater, Merced County, CA	Atwater, Merced County, CA	Atwater, Merced County, CA
		Utility	PG&E	PG&E	PG&E
		Digester and Generator System Design	Williams Engineering Assoc.	Williams Engineering Assoc.	Williams Engineering Assoc.
1	Manure Collection and Pretreatment				
	A	Lagoon	349,659	0	0
	B	Lagoon Liner			
	C	Manure Collection	19,227	19,227	19,227
	D	Vacuum Trailer			
	E	Solids Separator/ Grit Removal	177,445	177,445	177,445
	F	Collection Mix Tank	0	0	0
		Subtotal	546,331	196,672	196,672
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	0	0	0
	B	Lagoon Cover	341,250	341,250	341,250
	C	Digester Heating System	0	0	0
	D	Bacterial Treatment	0	0	0
		Subtotal	341,250	341,250	341,250
3	Energy Conversion and Gas Handling				
	A	Engine/generator (1 CAT G3412 TS engine-generator at 300 KW was purchased new)	90,115	90,115	0
	B	Overhaul, repair, and additional components	3,535	3,535	0
	C	Engine/generator room or building	0	0	0
	D	Gas Transport	211,540	211,540	211,540
	E	Flare (flare was constructed, not purchased)	0	0	0
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	0	0	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	305,190	305,190	211,540
4	General Construction				
	A	Excavation, trenching, and grading	0	0	0
	B	Concrete work and materials	91,730	91,730	91,730
	C	Electrical work and materials	33,978	33,978	0
	D	Other contractor/subcontractor	316,674	316,674	316,674
	E	Dairy labor used for construction and installation	180,237	180,237	180,237
	F	Transportation, Fuel and Heavy Equipment Rental	176,167	176,167	176,167
	G	Other Equipment and Materials	240,447	240,447	240,447
		Subtotal	1,039,233	1,039,233	1,005,255
5	System Design/Engineering				
	A	System Design/Engineering	147,252	147,252	147,252
	B	Other			
		Subtotal	147,252	147,252	147,252
6	Permits				
	A	Permits – air	1,080	1,080	1,080
	B	Permits – building	0	0	0
	C	Permits – water	0	0	0
	D	Other	0	0	0
		Subtotal	1,080	1,080	1,080
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	10,735	10,735	0
	B	Interconnect Equipment req'd by utility	60,701	60,701	0
		Subtotal	71,436	71,436	0

Cottonwood Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2005 so assume construction is 2004 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Other Construction Costs after System Completion - replaced H2S Scrubber (~$10,000), gas supply improvements, and electrical work	200,000	200,000	200,000
	B	Other			
	C	Tap, Controls, Unique Faclities			156,098
	D	Gas Clean-up and Processing			556,098
	E	SCADA Monitoring			87,805
	F	Pipeline from farm to gas pipeline - 1,000 feet			48,780
		Subtotal	200,000	200,000	1,048,781
9	Associated Construction Costs				
	A	Construction Financing: For Cottonwood, actual was given; for "no subsidy," calculate a value (e.g., 12 mos by total hard cost by 8% interest by 50% for level draw)	46,266	92,100	118,100
	B	Construction Insurance	0	0	0
	C	Other Overhead/Admin	0	0	0
	D	Land	0	0	0
		Subtotal	46,266	92,100	118,100
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	36,800	47,200
		Subtotal	0	36,800	47,200
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	23,000	29,500
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	23,000	29,500
12		**Total Loaded Cost**	**$2,698,038**	**$2,454,013**	**$3,146,630**

Sources of Funds

		Component	Cottonwood Dairy Actual Case	Cottonwood Dairy power case with no subsidies	Cottonwood Dairy pipeline-quality gas case with no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant	600,000	0	0
	4	Second Grant	240,000	0	0
	5	Equity	1,858,038	2,454,013	3,146,630
		Total	**$2,698,038**	**$2,454,013**	**$3,146,630**

Performance and Annual Operating Expenses

		Component	Cottonwood Dairy Actual Case	Cottonwood Dairy power case with no subsidies	Cottonwood Dairy pipeline-quality gas case with no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	300	300	112.958
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	300	300	96.014
	4	Capacity Wholesale to Utility (kW or Mcf/day)	0	300	96.014
		Capacity Retail to Steam Host (kW or Mcf/day)	300	0	0

Cottonwood Dairy

	5	Actual Hours/Year	8,760.0	8,760.0	8,760.0
		Forced Outage Hours	189.7	189.7	276.0
		Planned Outage Hours	1,460.0	1,460.0	600.0
		Hours of Operation after Outages	7,110.3	7,110.3	7,884.0
		Capacity Factor (%) after Outages	81.17%	81.17%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%
	7	**Net Power or Gas Produced for Sale**	2,133.09	2,133.09	19,965.26
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail;	100.00%	0.00%	0.00%
		Percent Sold Wholesale to Utility	0.00%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.896	0.000	0.000
		Full load operating hours	7,110.3	7,110.3	7,884.0
		Unfired Capacity (mlb/yr)	6,370.8	0.0	0.0
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	7.480	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	4.000	33.75	44.80
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	$13.12	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	0	0	0
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Carbon Credits ($/yr)	$30,000	$0	$0
		escalating by (%/year)	2.00%	2.00%	2.00%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	12,235	12,235	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	26,098.36	26,098.36	26,098.39
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy manure	Dairy manure	Dairy manure
		MM Btu/Mcf	0.633	0.633	0.633
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	3.6705	3.6705	3.3103
		Fuel #2 Consumption (mm Btu/hr)	0.0000	0.0000	0.0000
		Hours/year	7,110.3	7,110.3	7,884.0
		Total Consumption (mm Btu/yr)	26,098.36	26,098.36	26,098.39
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	505,440	505,440	505,440
		Biogas Potential (mm Btu/yr)	116,779.38	116,779.38	116,779.38
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Cottonwood Dairy

	23	Fuel #1 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0	0	0
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service	0	0	0
	27	Operations and Maintenance ($/year)	$74,400	$74,400	$74,400
	28	Consumables	0	0	0
	29	Operator	0	0	0
	30	Admin/Compliance	0	0	0
	31	Royalty (% of revenues)	0	0	0
	32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.	0	0	0
	35	Other			
	36	Iron Sponge Media for H2S Scrubber changed every 6-8 wk, at $5,000 – 8,000 each. Assume $7,000 at 7 times/yr. DO INCLUDE THIS, as it is an air pollution control cost, per Jan. 24 2008 communication with the farm. Scrubber with different technology will be installed at Columbard Dairy nearby.	50,000	50,000	50,000
	37	Gas Monitoring ($/year)	0	0	9,756
	38	Final Note: Important Facts that may help to optimize project.	For Cottonwood, about 50% of gas is flared. Power is used only at the cheese plant so far, but might be expanded to reach more of the farm. Second generator purchased at $500K, but not running well. What are its op exp, fuel consumption, and output? When digester is added at nearby Columbard Dairy, this will alter costs and performance - any estimates of addl cows, costs, and output? This farm has lowest NOx emissions.		

Hilarides Dairy

Data Inputs for Hilarides Dairy Introduction and Capital Costs					
		Component	**Hilarides Dairy actual ($)**	**Hilarides Dairy no subsidy power ($)**	**Hilarides Dairy no subsidy pipeline-quality gas ($)**
	Introduction				
		Digester System Type	Covered Lagoon	Covered Lagoon	Covered Lagoon
		Generator Nameplate Capacity (kW)	500 kW	500 kW	--
		First Full Start Year	2006	2006	2006
		Total Lactating Cows - For Hilarides 6,000 Heifers provide Biogas; 9,900 more cows, calves, bulls are not used	6,000	6,000	6,000
		Total Herd	6,000	6,000	6,000
		Farm Size (acres)	2,400	2,400	2,400
		Location	Lindsay, Tulare County, CA	Lindsay, Tulare County, CA	Lindsay, Tulare County, CA
		Utility	SCE	SCE	SCE
		Digester and Generator System Design	Sharp Energy (Roy Sharp)	Sharp Energy (Roy Sharp)	Sharp Energy (Roy Sharp)
1	Manure Collection and Pretreatment				
	A	Lagoon	0	0	0
	B	Lagoon Liner	0	0	0
	C	Manure Collection	0	0	0
	D	Vacuum Trailer	0	0	0
	E	Solids Separator/ Grit Removal	0	0	0
	F	Collection Mix Tank	0	0	0
		Subtotal	0	0	0
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	0	0	0
	B	Lagoon Cover	366,286	366,286	366,286
	C	Digester Heating System	0	0	0
	D	Bacterial Treatment	0	0	0
		Subtotal	366,286	366,286	366,286
3	Energy Conversion and Gas Handling				
	A	Engine/generator (500 kW, as 4 Caterpillar G342 engine-generator sets at 125 kW each, purchased used and then refurbished)	20,000	20,000	0
	B	Overhaul, repair, and additional components	158,613	158,613	0
	C	Engine/generator room or building	9,047	9,047	0
	D	Gas Transport	66,659	66,659	66,659
	E	Flare (flare was constructed, not purchased)	0	0	0
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	346,207	346,207	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	600,526	600,526	66,659
4	General Construction				
	A	Excavation, trenching, and grading	0	0	0
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	233,226	233,226	0
	D	Other contractor/subcontractor	0	0	0
	E	Dairy labor used for construction and installation	0	0	0
	F	Transportation, Fuel and Heavy Equipment Rental	0	0	0
	G	Other Equipment and Materials	0	0	0
		Subtotal	233,226	233,226	0
5	System Design/Engineering				
	A	System Design/Engineering	18,304	18,304	18,304
	B	Other			
		Subtotal	18,304	18,304	18,304
6	Permits				
	A	Permits – air	240	240	240
	B	Permits – building	0	0	0
	C	Permits – water	0	0	0
	D	Other	0	0	0
		Subtotal	240	240	240
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	1,319	1,319	0
	B	Interconnect Equipment req'd by utility	20,022	20,022	0
		Subtotal	21,341	21,341	0

Hilarides Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2006 so assume construction is 2005 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Other Construction Costs after System Completion	0	0	0
	B	Other			
	C	Tap, Controls, Unique Faclities			160,000
	D	Gas Clean-up and Processing			720,000
	E	SCADA Monitoring			90,000
	F	Pipeline from farm to gas pipeline - 1,000 feet			50,000
		Subtotal	0	0	1,020,000
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	49,600	58,900
	B	Construction Insurance	0	0	0
	C	Other Overhead/Admin	0	0	0
	D	Land	0	0	0
		Subtotal	0	49,600	58,900
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	19,800	23,500
		Subtotal	0	19,800	23,500
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	12,400	14,700
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	12,400	14,700
12		**Total Loaded Cost**	**$1,239,923**	**$1,321,723**	**$1,568,589**

Sources of Funds

		Component	Hilarides Dairy Actual Case	Hilarides Dairy power case with no subsidies	Hilarides Dairy pipeline-quality gas case with no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant	500,000	0	0
	4	Second Grant	0	0	0
	5	Equity	739,923	1,321,723	1,568,589
		Total	**$1,239,923**	**$1,321,723**	**$1,568,589**

Performance and Annual Operating Expenses

		Component	Hilarides Dairy Actual Case	Hilarides Dairy power case with no subsidies	Hilarides Dairy pipeline-quality gas case with no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	500	500	232.681
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	500	500	197.779
	4	Capacity Wholesale to Utility (kW or Mcf/day)	125	500	197.779
		Capacity Retail to Steam Host (kW or Mcf/day)	375	0	(0)

Hilarides Dairy

	5	Actual Hours/Year	8,760.0	8,760.0	8,760.0
		Forced Outage Hours	168.0	168.0	276.0
		Planned Outage Hours	1,827.0	1,827.0	600.0
		Hours of Operation after Outages	6,765.0	6,765.0	7,884.0
		Capacity Factor (%) after Outages	77.23%	77.23%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%
	7	**Net Power or Gas Produced for Sale**	3,382.50	3,382.50	33,979.49
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail;	61.95%	0.00%	0.00%
		Percent Sold Wholesale to Utility	38.05%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0	0	0
		Full load operating hours	6,765	6,765	7,884
		Unfired Capacity (mlb/yr)	0	0	0
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	6.00	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	4.00	9.91	11.91
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	0	0	0
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Carbon Credits	0	0	0
		escalating by (%/year)	2.00%	2.00%	2.00%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	13,132	13,132	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	44,418.99	44,418.99	44,417.66
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.523	0.523	0.523
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	6.566	6.566	5.634
		Fuel #2 Consumption (mm Btu/hr)	0.000	0.000	0.000
		Hours/year	6,765	6,765	7,884
		Total Consumption (mm Btu/yr)	44,418.99	44,418.99	44,417.66
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	540,000	540,000	540,000
		Biogas Potential (mm Btu/yr)	103,083.30	103,083.30	103,083.30
			--	--	--

Hilarides Dairy

23	Fuel #1 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
24	Fuel #2 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
25	Host Standby Demand Payment to Utility:	0	0	0
	Annual Expenses, that escalate with inflation unless otherwise indicated			
26	Service	0	0	0
27	Operations and Maintenance ($/year)	$21,000	$21,000	$21,000
28	Consumables	0	0	0
29	Operator	0	0	0
30	Admin/Compliance	0	0	0
31	Royalty (% of revenues)	0.00%	0.00%	0.00%
32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
	escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
	where base declines by (%/year)		4.00%	4.00%
	till hits a remainder of (%).		30.00%	30.00%
33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
	escalating by (%/year)	2.50%	2.50%	2.50%
34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.	0	0	0
35	Other			
36	Other	0	0	0
37	Gas Monitoring ($/year)	0	0	10,000
38	Final Note: Important Facts that may help to optimize project.	For Hilarides, about 20% to 40% of gas is flared. There are about 9,000 additional cows and livestock whose manure is not used. Will additional engine-generator be purchased, as considered in late 2006? System of redundant smaller engines seems to work well.		

Eden-Vale Dairy

		Data Inputs for Eden-Vale Dairy Introduction and Capital Costs			
		Component	**Eden-Vale Dairy actual ($)**	**Eden-Vale Dairy improved plant factor, no subsidy power ($)**	**Eden-Vale Dairy improved plant factor, no subsidy pipeline-quality gas ($)**
	Introduction				
		Digester System Type	Plug Flow (new system)	Plug Flow (new system)	Plug Flow (new system)
		Generator Nameplate Capacity (kW)	180 kW	180 kW	--
		First Full Start Year	2006	2006	2006
		Total Lactating Cows	800	800	800
		Total Herd	1,100	1,100	1,100
		Farm Size (acres)	145	145	145
		Location	Lemoorre, Kings County, CA	Lemoorre, Kings County, CA	Lemoorre, Kings County, CA
		Utility	PG&E	PG&E	PG&E
		Digester and Generator System Design	RCM Digesters	RCM Digesters	RCM Digesters
1	Manure Collection and Pretreatment				
	A	Lagoon	0	0	0
	B	Lagoon Liner	0	0	0
	C	Manure Collection	0	0	0
	D	Vacuum Trailer	0	0	0
	E	Solids Separator/ Grit Removal	63,500	63,500	63,500
	F	Collection Mix Tank	0	0	0
		Subtotal	63,500	63,500	63,500
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	311,214	311,214	311,214
	B	Lagoon Cover	0	0	0
	C	Digester Heating System	63,720	63,720	63,720
	D	Bacterial Treatment	0	0	0
		Subtotal	374,934	374,934	374,934
3	Energy Conversion and Gas Handling				
	A	Engine/generator (1 CAT 3406 engine-generator at 180 kW was purchased new)	104,196	104,196	0
	B	Overhaul, repair, and additional components	6,700	6,700	0
	C	Engine/generator room or building	27,516	27,516	0
	D	Gas Transport	46,740	46,740	46,740
	E	Flare (flare was constructed, not purchased)	0	0	0
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	0	0	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	185,152	185,152	46,740
4	General Construction				
	A	Excavation, trenching, and grading	156	156	156
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	0	0	0
	D	Other contractor/subcontractor	55,604	55,604	55,604
	E	Dairy labor used for construction and installation	0	0	0
	F	Transportation, Fuel and Heavy Equipment Rental	2,520	2,520	2,520
	G	Other Equipment and Materials	0	0	0
		Subtotal	58,280	58,280	58,280
5	System Design/Engineering				
	A	System Design/Engineering	65,385	65,385	65,385
	B	Other			
		Subtotal	65,385	65,385	65,385
6	Permits				
	A	Permits – air	0	0	0
	B	Permits – building	3,289	3,289	3,289
	C	Permits – water	0	0	0
	D	Other			
		Subtotal	3,289	3,289	3,289
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	43,535	43,535	0
	B	Interconnect Equipment req'd by utility	8,735	8,735	0
		Subtotal	52,270	52,270	0

Eden-Vale Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2006 so assume construction is 2005 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Initial Costs incurred prior to refurbishment	0	0	0
	B	Other Construction Costs after System Completion - engine and control repairs (during 2006)	2,000	2,000	2,000
	C	Tap, Controls, Unique Faclities			160,000
	D	Gas Clean-up and Processing			400,000
	E	SCADA Monitoring			90,000
	F	Pipeline from farm to gas pipeline - 1,000 feet			50,000
		Subtotal	2,000	2,000	702,000
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	32,200	52,600
	B	Construction Insurance			
	C	Other Overhead/Admin	0		
	D	Land	0		
		Subtotal	0	32,200	52,600
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	12,900	21,000
		Subtotal	0	12,900	21,000
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	8,000	13,100
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	8,000	13,100
12		**Total Loaded Cost**	**$804,810**	**$857,910**	**$1,400,828**

Sources of Funds

		Component	Eden-Vale Dairy Actual Case	Eden-Vale Dairy improved plant factor power case with no subsidies	Eden-Vale Dairy improved plant factor pipeline-gas case w/ no subsidies
	1	Senior Debt	0	0	0
	2	Junior Debt	0	0	0
	3	Grant	300,000	0	0
	4	Second Grant	0	0	0
	5	Equity	504,810	857,910	1,400,828
		Total	**$804,810**	**$857,910**	**$1,400,828**

Performance and Annual Operating Expenses

		Component	Eden-Vale Dairy Actual Case	Eden-Vale Dairy improved plant factor power case with no subsidies	Eden-Vale Dairy improved plant factor pipeline-gas case w/ no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	180	180	88.164
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	180	180	74.939
	4	Capacity Wholesale to Utility (kW or Mcf/day)	150	180	74.939
		Capacity Retail to Steam Host (kW or Mcf/day)	30	0	0.000

	5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
		Forced Outage Hours	4,030.00	720.00	276.00
		Planned Outage Hours	2,190.00	730.00	600.00
		Hours of Operation after Outages	2,540.00	7,310.00	7,884.00
		Capacity Factor (%) after Outages	29.00%	83.45%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%
	7	**Net Power or Gas Produced for Sale**	457.20	1,315.80	13,588.91
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail;	16.50%	0.00%	0.00%
		Percent Sold Wholesale to Utility	83.50%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.0360	0.0000	0.0000
		Full load operating hours	2,540.00	7,310.00	7,884.00
		Unfired Capacity (mlb/yr)	91.4	0.0	0.0
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	7.00	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	3.00	17.20	26.90
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	$13.12	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	$0.00	$0.00	$0.00
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Carbon Credits	0	0	0
		escalating by (%/year)	2.00%	2.00%	2.00%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	17,785	13,500	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	8,131.30	17,763.30	17,763.29
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.552	0.552	0.552
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	3.201	2.430	2.253
		Fuel #2 Consumption (mm Btu/hr)	0.0000	0.0000	0.0000
		Hours/year	2,540	7,310	7,884
		Total Consumption (mm Btu/yr)	8,131.30	17,763.30	17,763.29
	21	Auxiliary Fired Fuel: from Fuel #1, #2			
		Total Consumption (mm Btu/yr)	0.00	0.00	0.00
		Boiler Fuel	0.00	0.00	0.00
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	99,000	99,000	99,000
		Biogas Potential (mm Btu/yr)	19,946.52	19,946.52	19,946.52
			--	--	--

Eden-Vale Dairy

	23	Fuel #1 Unit Price	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0	0	0
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service			
	27	Operations and Maintenance	$18,000	$18,000	$18,000
	28	Consumables			
	29	Operator - Addtl Expense re: adjusted longer hours		3,000	3,000
	30	Admin/Compliance			
	31	Royalty (% of revenues)	0.00%	0.00%	0.00%
	32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.			
	35	Other			
	36	Other Costs	0	0	0
	37	Gas Monitoring ($/year)	0	0	10,000
	38	Final Note: Important Facts that may help to optimize project.	This Eden-Vale plant is run much below capacity because there is no market for power. The farmer has more manure that does not enter digester and some biogas is flared and does not feed the generator. He runs the system below capacity because operating expenses are higher than anticipated and revenues are lower than expected. There is little payment for excess power. He will connect more dairy load to the generator - beyond one meter now that connects a well, freestall lights, a pump, and generator load. On-farm main dairy acounts average about 37,000 kWh/month (or $2,600 at $0.070/kWh). Farmer also is considering recovered heat for dairy hot water.		

Koetsier Dairy

Data Inputs for Koetsier Dairy
Introduction and Capital Costs

		Component	Koetsier Dairy actual ($)	Koetsier Dairy improved plant factor, no subsidy power ($)	Koetsier Dairy improved plant factor, no subsidy pipeline-qual gas ($)
	Introduction				
		Digester System Type	Plug Flow (System Refurbishment)	Plug Flow (System Refurbishment)	Plug Flow (System Refurbishment)
		Generator Nameplate Capacity (kW)	260 kW	260 kW	--
		First Full Start Year	2006	2006	2006
		Total Lactating Cows	1,266	1,266	1,266
		Total Herd	2,285	2,285	2,285
		Farm Size (acres)	180 owned and 310 rented	180 owned and 310 rented	180 owned and 310 rented
		Location	Visalia, Tulare County, CA	Visalia, Tulare County, CA	Visalia, Tulare County, CA
		Utility	SCE	SCE	SCE
		Digester and Generator System Design	RCM Digesters	RCM Digesters	RCM Digesters
1	Manure Collection and Pretreatment				
	A	Lagoon	0	0	0
	B	Lagoon Liner	0	0	0
	C	Manure Collection	5,622	5,622	5,622
	D	Vacuum Trailer	117,588	117,588	117,588
	E	Solids Separator/ Grit Removal	63,168	63,168	63,168
	F	Collection Mix Tank	0	0	0
		Subtotal	186,378	186,378	186,378
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	84,853	84,853	84,853
	B	Lagoon Cover	0	0	0
	C	Digester Heating System	0	0	0
	D	Bacterial Treatment	0	0	0
		Subtotal	84,853	84,853	84,853
3	Energy Conversion and Gas Handling				
	A	Engine/generator - 1 used Caterpillar G342 genset at 135 kW was purchased and 1 Cat G342 genset at 135 kW was existing; both were refurbished.	10,000	10,000	0
	B	Overhaul, repair, and additional components	22,769	22,769	0
	C	Engine/generator room or building	14,576	14,576	0
	D	Gas Transport	13,250	13,250	13,250
	E	Flare (flare was constructed, not purchased)	2,750	2,750	2,750
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	11,995	11,995	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	75,340	75,340	16,000
4	General Construction				
	A	Excavation, trenching, and grading	0	0	0
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	0	0	0
	D	Other contractor/subcontractor	0	0	0
	E	Dairy labor used for construction and installation	0	0	0
	F	Transportation, Fuel and Heavy Equipment Rental	0	0	0
	G	Other Equipment and Materials	0	0	0
		Subtotal	0	0	0
5	System Design/Engineering				
	A	System Design/Engineering	9,963	9,963	9,963
	B	Other		0	0
		Subtotal	9,963	9,963	9,963
6	Permits				
	A	Permits – air	120	120	120
	B	Permits – building	20	20	20
	C	Permits – water	0	0	0
	D	Other			
		Subtotal	140	140	140
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	1,285	1,285	0
	B	Interconnect Equipment req'd by utility	5,128	5,128	0
		Subtotal	6,413	6,413	0

Koetsier Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2006 so assume construction is 2005 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Initial Costs incurred prior to refurbishment - turnkey 1985 digester system installed, that was non-operational by 2001	998,000	998,000	998,000
	B	Other Construction Costs after System Completion - remodelled input system	7,500	7,500	7,500
	C	Tap, Controls, Unique Faclities			160,000
	D	Gas Clean-up and Processing			400,000
	E	SCADA Monitoring			90,000
	F	Pipeline from farm to gas pipeline - 1,000 feet			50,000
		Subtotal	1,005,500	1,005,500	1,705,500
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	54,700	80,100
	B	Construction Insurance			
	C	Other Overhead/Admin	0		
	D	Land	0		
		Subtotal	0	54,700	80,100
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	21,900	32,000
		Subtotal	0	21,900	32,000
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	13,700	20,000
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	13,700	20,000
12		**Total Loaded Cost**	**$1,368,587**	**1,458,887**	**2,134,934**

Sources of Funds

		Component	Koetsier Dairy Actual Case	Koetsier Dairy improved plant factor power case with no subsidies	Koetsier Dairy improved plant factor pipeline gas case w/ no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant - $190,925 credits at $0.057/kWh for 5 years	0	0	0
	4	Second Grant	0	0	0
	5	Equity	1,368,587	1,458,887	2,134,934
		Total	**$1,368,587**	**$1,458,887**	**$2,134,934**

Performance and Annual Operating Expenses

		Component	Koetsier Dairy Actual Case	Koetsier Dairy improved plant factor pipeline gas case w/ no subsidies	Koetsier Dairy improved plant factor pipeline gas case w/ no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	260	260	126.205
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	260	260	107.274
	4	Capacity Wholesale to Utility (kW or Mcf/day)	130	260	107.274
		Capacity Retail to Steam Host (kW or Mcf/day)	130	0	0.000

Koetsier Dairy

	5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
		Forced Outage Hours	5,954.00	720.00	276.00
		Planned Outage Hours	730.00	730.00	600.00
		Hours of Operation after Outages	2,076.00	7,310.00	7,884.00
		Capacity Factor (%) after Outages	23.70%	83.45%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0	0	0
	7	**Net Power or Gas Produced for Sale**	539.76	1,900.60	19,628.45
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail;	76.20%	0.00%	0.00%
		Percent Sold Wholesale to Utility	23.80%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.044	0.000	0.000
		Full load operating hours/yr	2,076.00	7,310.00	7,884.00
		Unfired Capacity (mlb/yr)	91.3	0.0	0.0
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	6.00	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	3.00	19.90	27.95
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	$13.12	$0.00	$0.00
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	$0.00	$0.00	$0.00
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Carbon Credits	0	0	0
		escalating by (%/year)	2.00%	2.00%	2.00%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	16,645	13,500	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	8,984.31	25,658.10	25,658.12
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.557	0.557	0.557
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	4.328	3.510	3.254
		Fuel #2 Consumption (mm Btu/hr)	0.000	0.000	0.000
		Hours/year	2,076	7,310	7,884
		Total Consumption (mm Btu/yr)	8,984.31	25,658.10	25,658.12
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	205,650	205,650	205,650
		Biogas Potential (mm Btu/yr)	41,809.67	41,809.67	41,809.67
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Koetsier Dairy

	23	Fuel #1 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price ($/mm Btu)	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0	0	0
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service			
	27	Operations and Maintenance	$27,000	$27,000	$27,000
	28	Consumables			
	29	Operator - Addtl Expense re: adjusted longer hours	0	3,000	3,000
	30	Admin/Compliance			
	31	Royalty (% of revenues)	0.00%	0.00%	0.00%
	32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.			
	35	Other			
	36	Other Costs	$0.00	$0.00	$0.00
	37	Gas Monitoring ($/year)	0	0	10,000
	38	Final Note: Important Facts that may help to optimize project.	Because most net generation credits were forfeited, the Koetsier Dairy farmer does not run second engine-generator, underfeeds the one in use and flares 15% to 40% of dairy biogas. He retired part of dairy herd in 2003 by 270 cows to 1,233 cows. From a flush system that used too much water and reduced biogas production, this dairy converted to a scrape system, that scrapes manure twice per day and where a vacuum unit sends it to digester. Might measure how much recovered heat is used to heat digester. This project sought to refurbish existing, non-operational plug-flow digester system, and much of the Capital Cost (75%) was incurred in 1985. Farmer recently applied (2006?) to sell greenhouse gas credits on Chicago Climate Exchange (CCX), so system performance will improve. Separated solids are composted and used for bedding for cows in barns.		

Meadowbrook Dairy

Data Inputs for Meadowbrook Dairy
Introduction and Capital Costs

		Component	Meadowbrook Dairy actual ($)	Meadowbrook Dairy no subsidy power ($)	Meadowbrook Dairy no subsidy pipeline-quality gas ($)
	Introduction				
		Digester System Type	Plug Flow (new system)	Plug Flow (new system)	Plug Flow (new system)
		Generator Nameplate Capacity (kW)	160 kW	160 kW	--
		First Full Start Year	2005	2005	2005
		Total Lactating Cows	2,093	2,093	2,093
		Total Herd	3,194	3,194	3,194
		Farm Size (acres)	480 acres + 1,100 acres nearby	480 acres + 1,100 acres nearby	480 acres + 1,100 acres nearby
		Location	El Mirage, San Bernardino, CA	El Mirage, San Bernardino, CA	El Mirage, San Bernardino, CA
		Utility	SCE	SCE	SCE
		Digester and Generator System Design	RCM Digesters	RCM Digesters	RCM Digesters
1	Manure Collection and Pretreatment				
	A	Lagoon	0		
	B	Lagoon Liner	0		
	C	Manure Collection	0		
	D	Vacuum Trailer	0		
	E	Solids Separator/ Grit Removal	36,807	36,807	36,807
	F	Collection Mix Tank	7,995	7,995	7,995
		Subtotal	44,802	44,802	44,802
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	290,873	290,873	290,873
	B	Lagoon Cover	0	0	0
	C	Digester Heating System	35,326	35,326	35,326
	D	Bacterial Treatment	19,160	19,160	19,160
		Subtotal	345,359	345,359	345,359
3	Energy Conversion and Gas Handling				
	A	Engine/generator - One CAT 3406TA genset at 160 kW was purchased new.	135,562	135,562	0
	B	Overhaul, repair, and additional components	3,885	3,885	0
	C	Engine/generator room or building	23,393	23,393	0
	D	Gas Transport	50,921	50,921	50,921
	E	Flare (flare was constructed, not purchased)	2,420	2,420	2,420
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	0	0	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	216,181	216,181	53,341
4	General Construction				
	A	Excavation, trenching, and grading	580	580	580
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	32,119	32,119	0
	D	Other contractor/subcontractor	0	0	0
	E	Dairy labor used for construction and installation	0	0	0
	F	Transportation, Fuel and Heavy Equipment Rental	0	0	0
	G	Other Equipment and Materials	2,143	2,143	2,143
		Subtotal	34,842	34,842	2,723
5	System Design/Engineering				
	A	System Design/Engineering	60,321	60,321	60,321
	B	Other			
		Subtotal	60,321	60,321	60,321
6	Permits				
	A	Permits – air	0	0	0
	B	Permits – building	7,846	7,846	7,846
	C	Permits – water	0	0	0
	D	Other	0	0	0
		Subtotal	7,846	7,846	7,846
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	0	0	0
	B	Interconnect Equipment req'd by utility	11,253	11,253	0
		Subtotal	11,253	11,253	0

Meadowbrook Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2005 so assume construction is 2004 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Initial Costs incurred prior to refurbishment - Water/Liquids Management System including lagoon, pumps, mixing chamber, and electrical components. Assume $50,000 is lagoon, which is removed for no subsidy cases.	300,000	250,000	250,000
	B	Other Construction Costs after System Completion	0	0	0
	C	Tap, Controls, Unique Faclities			156,098
	D	Gas Clean-up and Processing			448,780
	E	SCADA Monitoring			87,805
	F	Pipeline from farm to gas pipeline - 1,000 feet			48,780
		Subtotal	300,000	250,000	991,463
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	38,800	60,200
	B	Construction Insurance			
	C	Other Overhead/Admin	0		
	D	Land	0		
		Subtotal	0	38,800	60,200
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	15,500	24,100
		Subtotal	0	15,500	24,100
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	9,700	15,100
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	9,700	15,100
12		**Total Loaded Cost**	**1,020,604**	**1,034,604**	**1,605,255**

Sources of Funds

		Component	Meadowbrook Dairy Actual Case	Meadowbrook Dairy power case with no subsidies	Meadowbrook Dairy pipeline-quality gas case with no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant	262,449	0	0
	4	Second Grant	200,000	0	0
	5	Equity	558,155	1,034,604	1,605,255
		Total	**$1,020,604**	**$1,034,604**	**$1,605,255**

Performance and Annual Operating Expenses

		Component	Meadowbrook Dairy Actual Case	Meadowbrook Dairy power case with no subsidies	Meadowbrook Dairy pipeline-quality gas case with no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	160	160	80.501
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	160	160	68.426
	4	Capacity Wholesale to Utility (kW or Mcf/day)	50	160	68.426
		Capacity Retail to Steam Host (kW or Mcf/day)	110	0	(0)

Meadowbrook Dairy

	5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
		Forced Outage Hours	1,517.03	1,517.03	276.00
		Planned Outage Hours	365.00	365.00	600.00
		Hours of Operation after Outages	6,878.0	6,878.0	7,884.0
		Capacity Factor (%) after Outages	78.52%	78.52%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%
	7	**Net Power or Gas Produced for Sale**	1,100.48	1,100.48	13,194.52
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail;	67.70%	0.00%	0.00%
		Percent Sold Wholesale to Utility	32.30%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.0200	0.0000	0.0000
		Full load operating hours	6,877.97	6,877.97	7,884.00
		Unfired Capacity (mlb/yr)	137.6	0.0	0.0
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0		
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0		
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	6.00	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	4.00	26.30	30.10
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	13.12	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	$0.00	$0.00	$0.00
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Carbon Credits	0	0	0
		escalating by (%/year)	2.00%	2.00%	2.00%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	15,673	15,673	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	17,247.75	17,247.75	17,247.75
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.587	0.587	0.587
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	2.508	2.508	2.188
		Fuel #2 Consumption (mm Btu/hr)	0.0000	0.0000	0.0000
		Hours/year	6,878	6,878	7,884
		Total Consumption (mm Btu/yr)	17,247.75	17,247.75	17,247.75
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	287,460	287,460	287,460
		Biogas Potential (mm Btu/yr)	61,589.74	61,589.74	61,589.74
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	23	Fuel #1 Unit Price	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0	0	0
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service - Engine Rebuild annually at $20,000 each. Omit for gas case.	20,000	20,000	0
	27	Operations and Maintenance	6,720	6,720	6,720
	28	Consumables - Oil Change at $255/week, as no H2S removal equipment to start. ($255/wk * 52 = $13,260.) Omit for gas case.	13,260	13,260	0
	29	Operator			
	30	Admin/Compliance			
	31	Royalty (% of revenues)	0.00%	0.00%	0.00%
	32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.			
	35	Other			
	36	Other Costs - Rebuilt engine at 6,000 hours. Changing oil once a week. See above - #26 and #28.	0	0	0
	37	Gas Monitoring ($/year)	0	0	9,756
	38	Final Note: Important Facts that may help to optimize project.	For Meadowbrook Dairy, operating expenses are high as oil change at $13,260/year and engine rebuild at $30,000/year are included. The Dairy may have installed H2S removal equipment later, but keep these operating expenses for now. Might measure how much recovered heat is used to heat digester. For retail on-farm offset, demand charges were not reduced, so full retail price is not recovered. The farmer is expanding dairy operations and load with calf flush facilities (i.e., 3 pumps, separator, compressor) and will add a second generator. Separated solids are composted and shipped to off-site farm, digested solids may be sold for potting soil, liquid effluent is employed for crop irrigation.		

Van Ommering Dairy

Data Inputs for Van Ommering Dairy
Introduction and Capital Costs

		Component	Van Ommering Dairy actual ($)	Van Ommering Dairy improved plant factor, no subsidy power ($)	Van Ommering Dairy improved plant factor, no subsidy pipeline-qual gas ($)
	Introduction				
		Digester System Type	Plug Flow (new system)	Plug Flow (new system)	Plug Flow (new system)
		Generator Nameplate Capacity (kW)	130 kW	130 kW	--
		First Full Start Year	2006	2006	2006
		Total Lactating Cows	480	480	480
		Total Herd	717	717	717
		Farm Size (acres)	200	200	200
		Location	Lakeside, San Diego County, CA	Lakeside, San Diego County, CA	Lakeside, San Diego County, CA
		Utility	SDG&E	SDG&E	SDG&E
		Digester and Generator System Design	RCM Digesters	RCM Digesters	RCM Digesters
1	Manure Collection and Pretreatment				
	A	Lagoon	0	0	0
	B	Lagoon Liner	0	0	0
	C	Manure Collection	47,686	47,686	47,686
	D	Vacuum Trailer	38,884	38,884	38,884
	E	Solids Separator/ Grit Removal	29,045	29,045	29,045
	F	Collection Mix Tank	0	0	0
		Subtotal	115,615	115,615	115,615
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	318,145	318,145	318,145
	B	Lagoon Cover	0	0	0
	C	Digester Heating System	52,248	52,248	52,248
	D	Bacterial Treatment	0	0	0
		Subtotal	370,393	370,393	370,393
3	Energy Conversion and Gas Handling				
	A	Engine/generator - One CAT 3406 genset at 130 kW was purchased new.	113,584	113,584	0
	B	Overhaul, repair, and additional components - generator piping	8,551	8,551	0
	C	Engine/generator room or building	9,521	9,521	0
	D	Gas Transport	64,444	64,444	64,444
	E	Flare (flare was constructed, not purchased)	0	0	0
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	0	0	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	196,100	196,100	64,444
4	General Construction				
	A	Excavation, trenching, and grading	28,660	28,660	28,660
	B	Concrete work and materials	0	0	0
	C	Electrical work and materials	35,271	35,271	0
	D	Other contractor/subcontractor	922	922	922
	E	Dairy labor used for construction and installation	0	0	0
	F	Transportation, Fuel and Heavy Equipment Rental	0	0	0
	G	Other Equipment and Materials	0	0	0
		Subtotal	64,853	64,853	29,582
5	System Design/Engineering				
	A	System Design/Engineering	48,440	48,440	48,440
	B	Other		0	0
		Subtotal	48,440	48,440	48,440
6	Permits				
	A	Permits – air	0	0	0
	B	Permits – building	2,000	2,000	2,000
	C	Permits – water	0	0	0
	D	Other (Env. Impact Report)	2,000	2,000	2,000
		Subtotal	4,000	4,000	4,000
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	37,435	37,435	0
	B	Interconnect Equipment req'd by utility	0	0	0
		Subtotal	37,435	37,435	0

Van Ommering Dairy

8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2006 so assume construction is 2005 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Initial Costs incurred prior to refurbishment	0	0	0
	B	Other Construction Costs after System Completion - for additional receiving tank	30,000	30,000	30,000
	C	Tap, Controls, Unique Faclities			160,000
	D	Gas Clean-up and Processing			400,000
	E	SCADA Monitoring			90,000
	F	Pipeline from farm to gas pipeline - 1,000 feet			50,000
		Subtotal	30,000	30,000	730,000
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	34,700	54,500
	B	Construction Insurance			
	C	Other Overhead/Admin	0		
	D	Land	0		
		Subtotal	0	34,700	54,500
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors.	0	13,900	21,800
		Subtotal	0	13,900	21,800
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	8,700	13,600
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	8,700	13,600
12		**Total Loaded Cost**	**$866,836**	**924,136**	**1,452,374**

Sources of Funds

		Component	Van Ommering Dairy Actual Case	Van Ommering Dairy improved plant factor power case with no subsidies	Van Ommering Dairy improved plant factor pipeline gas case w/ no subsidies
	1	Senior Debt	$0	$0	$0
	2	Junior Debt	0	0	0
	3	Grant	244,642	0	0
	4	Second Grant	150,000	0	0
	5	Equity	472,194	924,136	1,452,374
		Total	**$866,836**	**$924,136**	**$1,452,374**

Performance and Annual Operating Expenses

		Component	Van Ommering Dairy Actual Case	Van Ommering Dairy improved plant factor power case with no subsidies	Van Ommering Dairy improved plant factor pipeline gas case w/ no subsidies
	1	Contract Term (years)	20	20	20
	2	Inflation Rate (%)	2.50%	2.50%	2.50%
	3	**Power Production:**			
		Gross Rated Capacity (kW for Power;	130	130	51.994
		Mcf/day for Gas - inlet)			
		Gas Processing Losses (%)	0.00%	0.00%	15.00%
		In-Plant Use (%)	0.00%	0.00%	0.00%
		Net Rated Capacity (kW or Mcf/day)	130	130	44.195
	4	Capacity Wholesale to Utility (kW or Mcf/day)	130	130	44.195
		Capacity Retail to Steam Host (kW or Mcf/day)	0	0	0

Van Ommering Dairy

	5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
		Forced Outage Hours	3,170.00	720.00	276.00
		Planned Outage Hours	1,825.00	730.00	600.00
		Hours of Operation after Outages	3,765.00	7,310.00	7,884.00
		Capacity Factor (%) after Outages	42.98%	83.45%	90.00%
	6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%
	7	**Net Power or Gas Produced for Sale**	489.45	950.30	9,814.18
		(thou kWh/yr or mm Btu/yr)			
	8	Percent Sold Retail;	9.68%	0.00%	0.00%
		Percent Sold Wholesale to Utility	90.32%	100.00%	100.00%
	9	**Steam Produced for Sale**:			
		Unfired capacity rate (mlb/hr)	0.0243	0.0000	0.0000
		Full load operating hours/yr	3,765.00	7,310.00	7,884.00
		Unfired Capacity (mlb/yr)	91.5	0.0	0.0
	10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
	11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
	12	Retail Electricity Prices:			
		Energy (cents/kWh)	5.00	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	1.50%	1.50%
	13	Utility Electricity or Gas Prices:			
		Energy (cents/kWh or $/mm Btu)	5.00	25.50	38.50
		escalating by (%/year)	2.50%	0.00%	0.00%
		Demand ($/kW-capacity/month)	$0.00	n/a	n/a
		escalating by (%/year)	1.50%	0.00%	0.00%
	14	Retail Steam Prices #1:			
		Variable ($/mlb)	$13.12	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	$0.00	$0.00	$0.00
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Carbon Credits	0	0	0
		escalating by (%/year)	2.00%	2.00%	2.00%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	17,103	13,500	1.30719
		Btu in/Btu sold, gas)			
		Fuel Needed (mm Btu/yr)	8,371.06	12,829.05	12,829.00
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.676	0.676	0.676
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	2.2234	1.7550	1.6272
		Fuel #2 Consumption (mm Btu/hr)	0.0000	0.0000	0.0000
		Hours/year	3,765	7,310	7,884
		Total Consumption (mm Btu/yr)	8,371.06	12,829.05	12,829.00
	21	Auxiliary Fired Fuel: from Fuel #1, #2	0	0	0
		Total Consumption (mm Btu/yr)			
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	64,530	64,530	64,530
		Biogas Potential (mm Btu/yr)	15,922.13	15,922.13	15,922.13
			--	--	--

Van Ommering Dairy

23	Fuel #1 Unit Price	$0.00	$0.00	$0.00
24	Fuel #2 Unit Price	$0.00	$0.00	$0.00
25	Host Standby Demand Payment to Utility:	0	0	0
	Annual Expenses, that escalate with inflation unless otherwise indicated			
26	Service			
27	Operations and Maintenance	18,000	18,000	18,000
28	Consumables			
29	Operator - Addtl Expense re: adjusted longer hours		3,000	3,000
30	Admin/Compliance			
31	Royalty (% of revenues)	0.00%	0.00%	0.00%
32	Property Tax (% of depreciable base).	0.00%	1.00%	1.00%
	escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
	where base declines by (%/year)		4.00%	4.00%
	till hits a remainder of (%).		30.00%	30.00%
33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
	escalating by (%/year)	2.50%	2.50%	2.50%
34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.			
35	Other			
36	Other Cost -	0	0	0
37	Gas Monitoring ($/year)	0	0	10,000
38	Final Note: Important Facts that may help to optimize project.	Because some net generation credits were forfeited and there was no payment for surplus power, farmer does not run generator at capacity. He flares 40% to 50% of dairy biogas. After study period of June 2005 to May 2006, farmer built three barns to increse digester inflow by 8,000 gal/day and scraping to 3 times/week. Dairy electric load from 2 wells, 1 shop and 1 house were added to engine-generator output, plus lighting and fans for 3 new barns. Van Ommering system thus will beome more efficient.		

IEUA Dairy

Data Inputs for Inland Empire Utilities Agency (IEUA)
Introduction and Capital Costs

		Component	Inland Empire Utilities Agency actual ($) if engine operating hours matched digester hours	Inland Empire Utilities Agency no subsidy power ($)	Inland Empire Utilities Agency no subsidy pipeline-quality gas ($)
	Introduction				
		Digester System Type	Modified Mix Plug Flow	Modified Mix Plug Flow	Modified Mix Plug Flow
		Generator Nameplate Capacity (kW)	943 kW. Note that this is a theoretical case assuming all digester gas is sent to the engine-generator to produce electricity and that digester operating hours are equal to engine operating hours . Lately, the digester gas is partly used for space and process heating - to run an absorption chiller for air conditioning, to heat water for radiant floor heating, to heat the digester, etc. The engine operating hours are about half those of the digester. Lately, approximately 3,892.7 MWh/year of power are produced.	943 kW	--
		First Full Start Year	2006	2006	2006
		Total Lactating Cows	7,931	7,931	7,931
		Total Herd	9,843	9,843	9,843
		Farm Size (acres)	Formed in 1950, IEUA is the water utility for 242 square miles in western San Bernadino County, including 6 dairies; cities of Chino, Chino Hills, Fontana, Montclair, Ontario and Upland; and surrounding area.	See left.	See left.
		Location	Chino, San Bernardino County, CA	Chino, San Bernardino County, CA	Chino, San Bernardino County, CA
		Utility	SCE	SCE	SCE
		Digester and Generator System Design	Inland Empire Utilities Agency	Inland Empire Utilities Agency	Inland Empire Utilities Agency
1	Manure Collection and Pretreatment				
	A	Lagoon	0	0	0
	B	Lagoon Liner	0	0	0
	C	Manure Collection	17,248	17,248	17,248
	D	Vacuum Trailer	438,097	438,097	438,097
	E	Solids Separator/ Grit Removal	731,835	731,835	731,835
	F	Collection Mix Tank	259,944	259,944	259,944
		Subtotal	1,447,124	1,447,124	1,447,124
2	Digester and Gas Production Enhancements				
	A	Digester/Digester Tank	1,449,938	1,449,938	1,449,938
	B	Lagoon Cover	0	0	0
	C	Digester Heating System	0	0	0
	D	Bacterial Treatment	0	0	0
		Subtotal	1,449,938	1,449,938	1,449,938
3	Energy Conversion and Gas Handling				
	A	Engine/generator - One Waukesha 7042 at 1,000 kW and One Waukesha 5790 at 850 kW. Both gensets in place prior to this grant, so cost not included.	0	0	0
	B	Overhaul, repair, and additional components	0	0	0
	C	Engine/generator room or building	0	0	0
	D	Gas Transport	22,611	22,611	22,611
	E	Flare (flare was constructed, not purchased)	0	0	0
	F	Gas Treatment (scrubber, cleaning system)	0	0	0
	G	Controls, panels, meters and instrumentation	69,983	69,983	0
	H	Heat recovery (hot water or other)	0	0	0
		Subtotal	92,594	92,594	22,611

IEUA Dairy

4	General Construction				
	A	Excavation, trenching, and grading	200,875	200,875	200,875
	B	Concrete work and materials	34,473	34,473	34,473
	C	Electrical work and materials	0	0	0
	D	Other contractor/subcontractor	23,418	23,418	23,418
	E	Dairy labor used for construction and installation	97,531	97,531	97,531
	F	Transportation, Fuel and Heavy Equipment Rental	13,131	13,131	13,131
	G	Other Equipment and Materials	4,891	4,891	4,891
		Subtotal	374,319	374,319	374,319
5	System Design/Engineering				
	A	System Design/Engineering	127,763	127,763	127,763
	B	Other			
		Subtotal	127,763	127,763	127,763
6	Permits				
	A	Permits – air	0	0	0
	B	Permits – building	1,426	1,426	1,426
	C	Permits – water	0	0	0
	D	Other (Env. Impact Report)	0	0	0
		Subtotal	1,426	1,426	1,426
7	Utility Interconnect				
	A	Interconnect Permit and Inspection	0	0	0
	B	Interconnect Equipment req'd by utility	2,493	2,493	0
		Subtotal	2,493	2,493	0
8	Other Construction Costs after System Completion and Pipeline-Quality Gas Equipment. This plant starts up in 2006 so assume construction is 2005 . Deescalate by one year's inflation per year if startup is before 2006.				
	A	Initial Costs incurred prior to refurbishment - for Construction of initial plug-flow digester system at Regional Plant No. 5. Costs include piping, pumps, SARI capacity for flow/discharge; costs do not include design or generators. For No Subsidy case, remove $80,000 for lagoon excavation and construction, as part of normal dairy operation.	9,400,000	9,320,000	9,320,000
	B	Other Construction Costs after System Completion	0	0	0
	C	Tap, Controls, Unique Faclities			160,000
	D	Gas Clean-up and Processing			570,000
	E	SCADA Monitoring			90,000
	F	Pipeline from farm to gas pipeline - 1,000 feet			50,000
		Subtotal	9,400,000	9,320,000	10,190,000
9	Associated Construction Costs				
	A	Construction Financing (e.g., 12 mos by total hard cost by 8% interest by 50% if level draw)	0	512,600	544,500
	B	Construction Insurance	0	0	0
	C	Other Overhead/Admin	55,791	55,791	55,791
	D	Land	0	0	0
		Subtotal	55,791	568,391	600,291
10	Permanent Take-out Financing				
	A	Debt Financing Fees – for lender's legal and accounting costs; possibly loan commitment fee.	0	0	0
	B	Equity Financing Fees – for organizational fees, tax advice, other legal and accounting for owner/equity investors. This is 1.50% of cost.	0	205,800	218,500
		Subtotal	0	205,800	218,500
11	Reserves				
	A	Debt Service Reserve – assume 6 months for private power using project finance (where lenders are secured only by the one project). If Project owner uses balance sheet finance (so lenders are secured by other assets), probably no DSR.	0	0	0
	B	Working Capital Reserve (estimate)	0	128,200	136,100
	C	Equipment Repair Reserve Initial Payment	0		
	D	Other			
		Subtotal	0	128,200	136,100
12		**Total Loaded Cost**	**12,951,448**	**13,718,048**	**14,568,072**

IEUA Dairy

Sources of Funds

	Component	Inland Empire Utilities Agency Actual Case	Inland Empire Utilities Agency power case with no subsidies	Inland Empire Utilities Agency pipeline-quality gas case w/ no subsidies
1	Senior Debt	$0	$0	$0
2	Junior Debt	0	0	0
3	Grant - $773,175 credits at $0.057/kWh for output over 2,829,480 kWh (from 380 kW-capacity existing) for 5 years	0	0	0
4	Second Grant - from CEC	175,000	0	0
5	Equity	12,776,448	13,718,048	14,568,072
	Total	**$12,951,448**	**$13,718,048**	**$14,568,072**

Performance and Annual Operating Expenses

	Component	Inland Empire Utilities Agency Actual Case	Inland Empire Utilities Agency power case with no subsidies	Inland Empire Utilities Agency pipeline-quality gas case w/ no subsidies
1	Contract Term (years)	20	20	20
2	Inflation Rate (%)	2.50%	2.50%	2.50%
3	**Power Production:**			
	Gross Rated Capacity (kW for Power;	943	943	384.185185
	Mcf/day for Gas - inlet)			
	Gas Processing Losses (%)	0.00%	0.00%	15.00%
	In-Plant Use (%)	0.00%	0.00%	0.00%
	Net Rated Capacity (kW or Mcf/day)	943	943	326.557
4	Capacity Wholesale to Utility (kW or Mcf/day)	0	943	326.557
	Capacity Retail to Steam Host (kW or Mcf/day)	943	0	0
5	Actual Hours/Year	8,760.00	8,760.00	8,760.00
	Forced Outage Hours	547.50	547.50	276.00
	Planned Outage Hours	182.50	182.50	600.00
	Hours of Operation after Outages - IEUA states that opeating hours refer to the digester.	8,030.00	8,030.00	7,884.00
	Capacity Factor (%) after Outages	91.67%	91.67%	90.00%
6	Any Curtailment by Power Purchaser on top of outages? (%)	0.00%	0.00%	0.00%
7	**Net Power or Gas Produced for Sale**	7,572.29	7,572.29	69,513.62
	(thou kWh/yr or mm Btu/yr)			
8	Percent Sold Retail;	100.00%	0.00%	0.00%
	Percent Sold Wholesale to Utility	0.00%	100.00%	100.00%
9	**Steam Produced for Sale**:	This thermal production per year is the quantity reported in Wurdco's August 2006 report, which refers to start-up. Lately, thermal production is greater and power production is less than that shown here.		
	Unfired capacity rate (mlb/hr)	0.5828221	0.0000	0.0000
	Full load operating hours/yr	8,030.00	8,030.00	7,884.00
	Unfired Capacity (mlb/yr)	4,680.1	0.0	0.0
10	Auxiliary Firing: - Auxfired Capacity (mlb/yr)	0	0	0
11	Boiler Steam: - Boiler Capacity (mlb/yr)	0	0	0
12	Retail Electricity Prices:			
	Energy (cents/kWh)	8.00	n/a	n/a
	escalating by (%/year)	2.50%	2.50%	2.50%
	Demand ($/kW-capacity/month)	$0.00	n/a	n/a
	escalating by (%/year)	1.50%	1.50%	1.50%
13	Utility Electricity or Gas Prices:			
	Energy (cents/kWh or $/mm Btu)	4.00	33.50	38.30
	escalating by (%/year)	2.50%	0.00%	0.00%
	Demand ($/kW-capacity/month)	$0.00	n/a	n/a
	escalating by (%/year)	1.50%	0.00%	0.00%

IEUA Dairy

	14	Retail Steam Prices #1:			
		Variable ($/mlb)	$13.12	n/a	n/a
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)	$0.00	$0.00	$0.00
		escalating by (%/year)	1.50%	1.50%	1.50%
	15	Retail Steam Prices #2:			
		Variable ($/mlb)			
		escalating by (%/year)	2.50%	2.50%	2.50%
		Fixed ($mlb or other)			
		escalating by (%/year)	1.50%	1.50%	1.50%
	16	Byproduct Sales – Tipping Fee per year for manure	$18,600	$18,600	$18,600
		escalating by (%/year)	2.50%	2.50%	2.50%
	17	**Fuel Consumed:**			
		Plant Heat Rate (Btu/net kWh sold, power;	12,000	12,000	1.307190
		Btu in/Btu sold, gas). For power, 12,000 is PERI/IEUA initial ballpark estimate.			
		Fuel Needed (mm Btu/yr)	90,867.48	90,867.48	90,867.51
	18	Adjustments and Conversion Factors:			
		Fuel #1	Dairy Manure	Dairy Manure	Dairy Manure
		MM Btu/Mcf	0.648	0.648	0.648
		Fuel #2	Natural Gas	Natural Gas	Natural Gas
		MM Btu/Mcf	1.020	1.020	1.020
		(Fuel #2 is not used, so moot.)			
	19	Annual Heat Rate Increase			
		Fuel #1	0.00%	0.10%	0.00%
		Fuel #2	0.00%	0.10%	0.00%
	20	Fuel #1 Percentage	100.00%	100.00%	100.00%
		Fuel #1 Consumption (mm Btu/hr)	11.3160	11.3160	11.5256
		Fuel #2 Consumption (mm Btu/hr)	0.0000	0.0000	0.0000
		Hours/year	8,030	8,030	7,884
		Total Consumption (mm Btu/yr)	90,867.48	90,867.48	90,867.51
	21	Auxiliary Fired Fuel: from Fuel #1, #2			
		Total Consumption (mm Btu/yr)	0	0	0
		Boiler Fuel	0	0	0
	22	Fuel Limit based upon Total Herd			
		Biogas Potential at 90 cf per animal in total herd/dy (cf/day)	885,870	885,870	885,870
		Biogas Potential (mm Btu/yr)	209,525.97	209,525.97	209,525.97
			--	--	--
	23	Fuel #1 Unit Price	$0.00	$0.00	$0.00
	24	Fuel #2 Unit Price	$0.00	$0.00	$0.00
	25	Host Standby Demand Payment to Utility:	0	0	0
		Annual Expenses, that escalate with inflation unless otherwise indicated			
	26	Service			
	27	Operations and Maintenance	$629,666.00	$629,666.00	$629,666.00
	28	Consumables			
	29	Operator			
	30	Admin/Compliance			
	31	Royalty (% of revenues)	0.00%	0.00%	0.00%

IEUA Dairy

	32	Property Tax (% of depreciable base). IEUA is a tax-exempt public agency.	0.00%	0.00%	0.00%
		escalating by (%/year), Proposition 13	2.00%	2.00%	2.00%
		where base declines by (%/year)		4.00%	4.00%
		till hits a remainder of (%).		30.00%	30.00%
	33	Insurance (% of depreciable base, escalating with inflation to achieve replacement value)	0.00%	0.60%	0.60%
		escalating by (%/year)	2.50%	2.50%	2.50%
	34	Major Maintenance Repair and Overhaul Fund. Assume some percentage of depreciable base as overhaul every 5, 7, or 10 years. The overhaul amount is escalated by inflation to find the sum needed by the end of year 5, 7, or 10. If 7, one seventh of that amount is saved each year and deposited to a reserve fund and, after performing the overhaul, repair depreciation is taken, straight-line, over the next seven years.			
	35	Other			
	36	Other			
	37	Gas Monitoring ($/year)	0	0	10,000
	38	Final Note: Important Facts that may help to optimize project.	The two engine-generators are sized at 1,850 kW, but Regional Plant No. 5 (RP-5) digester/biogas capacity is 943 kW. (It was 380 initially, with expansion work under this grant at 563 kW.) Expected construction costs nearly tripled from time of application (~2003) to construction. Further, all $9.3 million cost for the initial plug-flow digester is included, although some of the early equipment was discarded. Wurdco's Aug 2006 report showed the plant in start-up with a 17% capacity factor. In 2006, Wurdco said power production was so low, the plant did not pass the limit where it would earn an incentive payment (if production is over 2,829,480 kWh/yr or 380 kW). Unclear if the plant has now received this payment. In addition, Wurdco describes an iron sponge as part of H2S scrubber, where media is changed periodically, adding to op. expense.		
			Discussion with IEUA in early 2008 said operating hours are now over 90%. That is, annual operating hours for the digester are 8,030. The case presented here assumes all gas is sent to the engine-generator, so operating hours for the engine-generator match those of the digester. In reality, IEUA uses much of the digester gas for thermal applications (e.g., to run an absorption chiller for air conditioning, to heat water for radiant floor heating, to heat the digester). In reality, operating hours for the engine-generator are about half those of the digester and 3,892.725 MWh/year of electricity is produced. The case presented here is somwhat theoretical.		

Table A- 3 Actual On-Site Power LCOEs

Engineering Assumptions and Cash Flow Results for Actual electric power cases.

	Dairy Name	Size (kW)	Plant Capacity Factor (%)	Nominal Levelized Power Revenues ($/kWh in 2007$)	Nominal Levelized after-tax O&M** Cost ($/kWh in 2007$)	Nominal Levelized Capital Cost of manure to electricity ($/kWh in 2007$)	Constant Levelized Revenues ($/kWh in 2007$)	Constant Levelized after-tax O&M** Cost ($/kWh in 2007$)	Constant Levelized Capital Cost of manure to electricity ($/kWh in 2007$)
1	**Hilarides Dairy**	500.0	77.23%						
	covered lagoon								
	total			0.0643	0.0045	0.0598	0.0524	0.0037	0.0487
	retail			0.0736			0.0600		
	wholesale			0.0491			0.0400		
2	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	covered lagoon								
	total			0.0940	0.0434	0.0506	0.0767	0.0354	0.0413
	retail			0.0940			0.0767		
	wholesale			0.0000			0.0000		
3	**Blakes Landing Dairy**	75.0	38.48%						
	covered lagoon								
	total			0.1409	0.0116	0.1293	0.1149	0.0095	0.1054
	retail			0.1509			0.1230		
	wholesale			0.1257			0.1025		
4	**Castelanelli Bros. Dairy**	160.0	81.00%		O&M + Engine rebuild			O&M + Engine rebuild	
	covered lagoon								
	total			0.0817	0.0094	0.0723	0.0666	0.0077	0.0589
	retail			0.0910			0.0742		
	wholesale			0.0724			0.0590		
5	**Koetsier Dairy**	260.0	23.70%						
	plug flow								
	total			0.0648	0.0364	0.0284	0.0529	0.0296	0.0233
	retail			0.0736			0.0600		
	wholesale			0.0368			0.0300		
6	**Van Ommering Dairy**	130.0	42.98%						
	plug flow								
	total			0.0613	0.0267	0.0346	0.0500	0.0218	0.0282
	retail			0.0613			0.0500		
	wholesale			0.0613			0.0500		
7	**Meadowbrook Dairy**	160.0	78.52%		O&M, oil change + Engine rebuild			O&M, oil change + Engine rebuild	
	plug flow								
	total			0.0673	0.0271	0.0402	0.0549	0.0221	0.0328
	retail			0.0754			0.0615		
	wholesale			0.0503			0.0410		
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	943.0	91.67%						
	modified mix plug flow - Assume output is mostly power, that engine-generator hours equal digester operating hours.								
	total			0.0981	0.1020	(0.0039)	0.0800	0.0832	(0.0032)
	retail			0.0981			0.0800		
	wholesale			0.0000			0.0000		
10	**Eden-Vale Dairy**	180.0	29.00%						
	plug flow								
	total			0.0449	0.0286	0.0163	0.0366	0.0233	0.0133
	retail			0.0859			0.0700		
	wholesale			0.0368			0.0300		

* For all tables, heat rate does not matter to cost results, because the fuel is free. Fuel consumed is reported for information's sake with earnings. With a low heat rate, less gas is flared and/or the engine-generator is more efficient.

** after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

*** Dairy Methane Digester System Program Evaluation Report, Dairy Power Production Program; prepared by WURD, August 2006.

Table A- 4 No Subsidy Power LCOEs

	Engineering Assumptions and Cash Flow Results for "No Subsidy" electric power.								
	Dairy Name	Size (kW)	Plant Capacity Factor (%)	Nominal Levelized Power Revenues ($/kWh in 2007$)	Nominal Levelized after-tax O&M* Cost ($/kWh in 2007$)	Nominal Levelized Capital Cost of manure to electricity ($/kWh in 2007$)	Constant Levelized Revenues ($/kWh in 2007$)	Constant Levelized after-tax O&M* Cost ($/kWh in 2007$)	Constant Levelized Capital Cost of manure to electricity ($/kWh in 2007$)
1	**Hilarides Dairy**	500.0	77.23%						
	covered lagoon								
	total			0.1016	0.0045	0.0971	0.0828	0.0037	0.0791
1a	**Hilarides Dairy**	500.0	77.23%						
	total			0.0349	0.0045	0.0304	0.0284	0.0037	0.0247
2	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	covered lagoon								
	total			0.3546	0.0434	0.3112	0.2891	0.0354	0.2537
2a	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	total			0.1565	0.0434	0.1131	0.1276	0.0354	0.0922
3	**Blakes Landing Dairy**	75.0	38.48%						
	covered lagoon								
	total			0.3719	0.0116	0.3603	0.3032	0.0095	0.2937
3a	**Blakes Landing Dairy**	75.0	38.48%						
	total			0.1177	0.0116	0.1061	0.0959	0.0095	0.0864
4	**Castelanelli Bros. Dairy**	160.0	81.00%						
	covered lagoon								
	total			0.2269	0.0094	0.2175	0.1850	0.0077	0.1773
4a	**Castelanelli Bros. Dairy**	160.0	81.00%						
	total			0.0756	0.0094	0.0662	0.0617	0.0077	0.0540
5	**Koetsier Dairy**	260.0	83.45%						
	plug flow		adjusted						
	total		from 23.7%	0.2040	0.0115	0.1925	0.1663	0.0094	0.1569
5a	**Koetsier Dairy**	260.0	83.45%						
	total			0.0718	0.0115	0.0603	0.0585	0.0094	0.0491
6	**Van Ommering Dairy**	130.0	83.45%						
	plug flow		adjusted						
	total		from 43.0%	0.2614	0.0161	0.2453	0.2131	0.0131	0.2000
6a	**Van Ommering Dairy**	130.0	83.45%						
	total			0.0933	0.0161	0.0772	0.0760	0.0131	0.0629
7	**Meadowbrook Dairy**	160.0	78.52%						
	plug flow								
	total			0.2763	0.0271	0.2492	0.2253	0.0221	0.2032
7a	**Meadowbrook Dairy**	160.0	78.52%						
	total			0.1124	0.0271	0.0853	0.0917	0.0221	0.0696
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	943.0	91.67%						
	modified mix plug flow								
	total			0.3434	0.1020	0.2414	0.2799	0.0832	0.1967
9a	**IEUA**	943.0	91.67%						
	total			0.2122	0.1020	0.1102	0.1730	0.0832	0.0898
10	**Eden-Vale Dairy**	180.0	83.45%						
	plug flow		adjusted						
	total		from 29.0%	0.1763	0.0116	0.1647	0.1437	0.0095	0.1342
10a	**Eden-Vale Dairy**	180.0	83.45%						
	total			0.0646	0.0116	0.0530	0.0526	0.0095	0.0431

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 5 No Subsidy Pipeline-Quality Gas LCOEs

	Dairy Name	Digester Size; Net Gas Prod'n (Mcf/day - inlet)	Plant Capacity Factor (%)	Nominal Levelized Gas Revenues ($/therm in 2007$)	Nominal Levelized after-tax O&M* Cost ($/therm in 2007$)	Nominal Levelized Capital Cost of manure to gas ($/therm in 2007$)	Constant Levelized Revenues ($/therm in 2007$)	Constant Levelized after-tax O&M* Cost ($/therm in 2007$)	Constant Levelized Capital Cost of manure to gas ($/therm in 2007$)
Engineering Assumptions and Cash Flow Results for specific objective 2 - "No Subsidy" pipeline quality gas.									
1	**Hilarides Dairy**	232.7	90.00%						
	covered lagoon	197.8							
	total or wholesale			1.2452	0.0676	1.1776	1.0152	0.0551	0.9601
1a	**Hilarides Dairy**	232.7	90.00%						
	total or wholesale	197.8		0.4391	0.0676	0.3715	0.3580	0.0551	0.3029
2	**Cottonwood (Gallo Cattle)**	113.0	90.00%						
	covered lagoon	96.0							
	total or wholesale			4.8009	0.5106	4.2903	3.9141	0.4163	3.4978
2a	**Cottonwood (Gallo Cattle)**	113.0	90.00%						
	total or wholesale	96.0		2.0147	0.5106	1.5041	1.6425	0.4163	1.2262
3	**Blakes Landing Dairy**	14.8	90.00%						
	covered lagoon	12.6							
	total or wholesale			34.3996	0.3898	34.0098	28.0453	0.3178	27.7275
3a	**Blakes Landing Dairy**	14.8	90.00%						
	total or wholesale	12.6		9.9448	0.3898	9.5550	8.1078	0.3178	7.7900
4	**Castelanelli Bros. Dairy**	89.1	90.00%						
	covered lagoon	75.8							
	total or wholesale			4.2330	0.1033	4.1297	3.4511	0.0842	3.3669
4a	**Castelanelli Bros. Dairy**	89.1	90.00%						
	total or wholesale	75.8		1.2967	0.1033	1.1934	1.0572	0.0842	0.9730
5	**Koetsier Dairy**	126.2	90.00%						
	plug flow	107.3							
	total or wholesale			2.9222	0.1511	2.7711	2.3824	0.1232	2.2592
5a	**Koetsier Dairy**	126.2	90.00%						
	total or wholesale	107.3		1.0141	0.1511	0.8630	0.8268	0.1232	0.7036
6	**Van Ommering Dairy**	52.0	90.00%						
	plug flow	44.2							
	total or wholesale			4.0252	0.2342	3.7910	3.2817	0.1909	3.0908
6a	**Van Ommering Dairy**	52.0	90.00%						
	total or wholesale	44.2		1.4219	0.2342	1.1877	1.1592	0.1909	0.9683
7	**Meadowbrook**	80.5	90.00%						
	plug flow	68.4							
	total or wholesale			3.2256	0.0949	3.1307	2.6298	0.0774	2.5524
7a	**Meadowbrook**	80.5	90.00%						
	total or wholesale	68.4		1.0181	0.0949	0.9232	0.8300	0.0774	0.7526
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	384.2	90.00%						
	modified mix plug flow	326.6							
	total or wholesale			4.0043	1.1513	2.8530	3.2646	0.9386	2.3260
9a	**IEUA**	384.2	90.00%						
	total or wholesale	326.6		2.4465	1.1513	1.2952	1.9946	0.9386	1.0560
10	**Eden-Vale Dairy**	88.2	90.00%						
	plug flow	74.9							
	total or wholesale			2.8124	0.1691	2.6433	2.2929	0.1379	2.1550
10a	**Eden-Vale Dairy**	88.2	90.00%						
	total or wholesale	74.9		1.0037	0.1691	0.8346	0.8183	0.1379	0.6804

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 6 No Subsidy, Enhanced Environmental Quality Power LCOEs

Engineering Assumptions and Cash Flow Results for "No Subsidy" electric power, produced in an Environmentally Superior Way.

	Dairy Name	Size (kW)	Plant Capacity Factor (%)	Nominal Levelized Power Revenues ($/kWh in 2007$)	Nominal Levelized after-tax O&M* Cost ($/kWh in 2007$)	Nominal Levelized Capital Cost of manure to electricity ($/kWh in 2007$)	Constant Levelized Revenues ($/kWh in 2007$)	Constant Levelized after-tax O&M* Cost ($/kWh in 2007$)	Constant Levelized Capital Cost of manure to electricity ($/kWh in 2007$)
1	**Hilarides Dairy**	500.0	77.23%						
	covered lagoon								
	total			0.1855	0.0060	0.1795	0.1513	0.0049	0.1464
2	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	covered lagoon								
	total			0.4486	0.0458	0.4028	0.3657	0.0374	0.3283
3	**Blakes Landing Dairy**	75.0	38.48%						
	covered lagoon								
	total			0.4465	0.0318	0.4147	0.3640	0.0259	0.3381
4	**Castelanelli Bros. Dairy**	160.0	81.00%						
	covered lagoon								
	total			0.2879	0.0139	0.2740	0.2347	0.0114	0.2233
5	**Koetsier Dairy**	260.0	83.45%						
	plug flow		adjusted						
	total		from 23.7%	0.2132	0.0141	0.1991	0.1738	0.0115	0.1623
6	**Van Ommering Dairy**	130.0	83.45%						
	plug flow		adjusted						
	total		from 43.0%	0.2768	0.0214	0.2554	0.2256	0.0175	0.2081
7	**Meadowbrook Dairy**	160.0	78.52%						
	plug flow								
	total			0.2910	0.0317	0.2593	0.2373	0.0258	0.2115
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	943.0	91.67%						
	modified mix plug flow								
	total			0.3454	0.1031	0.2423	0.2816	0.0841	0.1975
10	**Eden-Vale Dairy**	180.0	83.45%						
	plug flow		adjusted						
	total		from 29.0%	0.1886	0.0155	0.1731	0.1538	0.0126	0.1412

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 7 No Subsidy, Enhanced Environmental Quality Pipeline-Quality Gas LCOEs

Engineering Assumptions and Cash Flow Results for "No Subsidy" pipeline quality gas, produced in an environmentally superior way.									
	Dairy Name	Digester Size; Net Gas Prod'n (Mcf/day - inlet)	Plant Capacity Factor (%)	Nominal Levelized Gas Revenues ($/therm in 2007$)	Nominal Levelized after-tax O&M* Cost ($/therm in 2007$)	Nominal Levelized Capital Cost of manure to gas ($/therm in 2007$)	Constant Levelized Revenues ($/therm in 2007$)	Constant Levelized after-tax O&M* Cost ($/therm in 2007$)	Constant Levelized Capital Cost of manure to gas ($/therm in 2007$)
1	**Hilarides Dairy**	232.7	90.00%						
	covered lagoon	197.8							
	total or wholesale			2.0962	0.0829	2.0133	1.7090	0.0676	1.6414
2	**Cottonwood (Gallo Cattle)**	113.0	90.00%						
	covered lagoon	96.0							
	total or wholesale			5.8190	0.5366	5.2824	4.7441	0.4375	4.3066
3	**Blakes Landing Dairy**	14.8	90.00%						
	covered lagoon	12.6							
	total or wholesale			35.1283	0.5841	34.5442	28.6395	0.4762	28.1633
4	**Castelanelli Bros. Dairy**	89.1	90.00%						
	covered lagoon	75.8							
	total or wholesale			4.6831	0.1367	4.5464	3.8180	0.1114	3.7066
5	**Koetsier Dairy**	126.2	90.00%						
	plug flow	107.3							
	total or wholesale			3.0110	0.1775	2.8335	2.4548	0.1447	2.3101
6	**Van Ommering Dairy**	52.0	90.00%						
	plug flow	44.2							
	total or wholesale			4.1715	0.2870	3.8845	3.4010	0.2340	3.1670
7	**Meadowbrook**	80.5	90.00%						
	plug flow	68.4							
	total or wholesale			3.3542	0.1342	3.2200	2.7346	0.1094	2.6252
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	384.2	90.00%						
	modified mix plug flow	326.6							
	total or wholesale			4.0252	1.1639	2.8613	3.2817	0.9489	2.3328
10	**Eden-Vale Dairy**	88.2	90.00%						
	plug flow	74.9							
	total or wholesale			2.9274	0.2073	2.7201	2.3867	0.1690	2.2177

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 8 Carbon Credit and PTC Power LCOEs

Engineering Assumptions and Cash Flow Results for carbon credit and carbon credit and Section 45 PTC sensitivity cases for "No Subsidy" electric power.

	Dairy Name	Size (kW)	Plant Capacity Factor (%)	Nominal Levelized Power Revenues ($/kWh in 2007$)	Nominal Levelized after-tax O&M* Cost ($/kWh in 2007$)	Nominal Levelized Capital Cost of manure to electricity ($/kWh in 2007$)	Constant Levelized Revenues ($/kWh in 2007$)	Constant Levelized after-tax O&M* Cost ($/kWh in 2007$)	Constant Levelized Capital Cost of manure to electricity ($/kWh in 2007$)
1	**Hilarides Dairy**	500.0	77.23%						
	covered lagoon								
	total w/ carbon credit			0.0832	0.0045	0.0787	0.0679	0.0037	0.0642
1a	**Hilarides Dairy**	500.0	77.23%						
	total w/ carbon credit & PTC			0.0680	0.0045	0.0635	0.0554	0.0037	0.0517
2	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	covered lagoon								
	total w/ carbon credit			0.3373	0.0434	0.2939	0.2750	0.0354	0.2396
2a	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	total w/ carbon credit & PTC			0.3225	0.0434	0.2791	0.2630	0.0354	0.2276
3	**Blakes Landing Dairy**	75.0	38.48%						
	covered lagoon								
	total w/ carbon credit			0.3520	0.0116	0.3404	0.2869	0.0095	0.2774
3a	**Blakes Landing Dairy**	75.0							
	total w/ carbon credit & PTC								
4	**Castelanelli Bros. Dairy**	160.0	81.00%						
	covered lagoon								
	total w/ carbon credit			0.2028	0.0094	0.1934	0.1653	0.0077	0.1576
4a	**Castelanelli Bros. Dairy**	160.0	81.00%						
	total w/ carbon credit & PTC			0.1870	0.0094	0.1776	0.1525	0.0077	0.1448
5	**Koetsier Dairy**	260.0	83.45%						
	plug flow		adjusted						
	total w/ carbon credit		from 23.7%	0.1855	0.0115	0.1740	0.1513	0.0094	0.1419
5a	**Koetsier Dairy**	260.0	83.45%						
	total w/ carbon credit & PTC			0.1702	0.0115	0.1587	0.1387	0.0094	0.1293
6	**Van Ommering Dairy**	130.0	83.45%						
	plug flow		adjusted						
	total w/ carbon credit		from 43.0%	0.2419	0.0161	0.2258	0.1972	0.0131	0.1841
6a	**Van Ommering Dairy**	130.0							
	total w/ carbon credit & PTC								
7	**Meadowbrook Dairy**	160.0	78.52%						
	plug flow								
	total w/ carbon credit			0.2543	0.0271	0.2272	0.2073	0.0221	0.1852
7a	**Meadowbrook Dairy**	160.0	78.52%						
	total w/ carbon credit & PTC			0.2395	0.0271	0.2124	0.1953	0.0221	0.1732
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	943.0	91.67%						
	modified mix plug flow								
	total w/ carbon credit			0.3260	0.1020	0.2240	0.2657	0.0832	0.1825
9a	**IEUA**	943.0							
	total w/ carbon credit & PTC								
10	**Eden-Vale Dairy**	180.0	83.45%						
	plug flow		adjusted						
	total w/ carbon credit		from 29.0%	0.1579	0.0116	0.1463	0.1287	0.0095	0.1192
10a	**Eden-Vale Dairy**	180.0	83.45%						
	total w/ carbon credit & PTC			0.1425	0.0116	0.1309	0.1162	0.0095	0.1067

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 9 Carbon Credit Pipeline-Quality Gas LCOEs

	Engineering Assumptions and Cash Flow Results for carbon credit sensitivity cases for "No Subsidy" pipeline quality gas.									
	Dairy Name	Digester Size; Net Gas Prod'n (Mcf/day - inlet)	Plant Capacity Factor (%)	Nominal Levelized Gas Revenues ($/therm in 2007$)	Nominal Levelized after-tax O&M* Cost ($/therm in 2007$)	Nominal Levelized Capital Cost of manure to gas ($/therm in 2007$)	Constant Levelized Revenues ($/therm in 2007$)	Constant Levelized after-tax O&M* Cost ($/therm in 2007$)	Constant Levelized Capital Cost of manure to gas ($/therm in 2007$)
1	**Hilarides Dairy**	232.7	90.00%						
	covered lagoon	197.8							
	total w/ carbon credit			1.0560	0.0676	0.9884	0.8609	0.0551	0.8058
2	**Cottonwood (Gallo Cattle)**	113.0	90.00%						
	covered lagoon	96.0							
	total w/ carbon credit			4.6080	0.5106	4.0974	3.7569	0.4163	3.3406
3	**Blakes Landing Dairy**	14.8	90.00%						
	covered lagoon	12.6							
	total w/ carbon credit			34.2388	0.3898	33.8490	27.9143	0.3178	27.5965
4	**Castelanelli Bros. Dairy**	89.1	90.00%						
	covered lagoon	75.8							
	total w/ carbon credit			4.0294	0.1033	3.9261	3.2851	0.0842	3.2009
5	**Koetsier Dairy**	126.2	90.00%						
	plug flow	107.3							
	total w/ carbon credit			2.7288	0.1511	2.5777	2.2247	0.1232	2.1015
6	**Van Ommering Dairy**	52.0	90.00%						
	plug flow	44.2							
	total w/ carbon credit			3.8265	0.2342	3.5923	3.1197	0.1909	2.9288
7	**Meadowbrook**	80.5	90.00%						
	plug flow	68.4							
	total w/ carbon credit			3.0327	0.0949	2.9378	2.4725	0.0774	2.3951
8	**Lourenco Dairy**	No operational data		No operating data.					
9	**IEUA**	384.2	90.00%						
	modified mix plug flow	326.6							
	total w/ carbon credit			3.8056	1.1513	2.6543	3.1027	0.9386	2.1641
10	**Eden-Vale Dairy**	88.2	90.00%						
	plug flow	74.9							
	total w/ carbon credit			2.6242	0.1691	2.4551	2.1395	0.1379	2.0016

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 10 No Subsidy Carbon Credit, PTC and Bonus Depreciation Power LCOE's for three plants

Engineering Assumptions and Cash Flow Results for carbon credit, Section 45 PTC, and 50% Bonus Depreciation sensitivity cases for "No Subsidy" electric power.

	Dairy Name	Size (kW)	Plant Capacity Factor (%)	Nominal Levelized Power Revenues ($/kWh in 2007$)	Nominal Levelized after-tax O&M* Cost ($/kWh in 2007$)	Nominal Levelized Capital Cost of manure to electricity ($/kWh in 2007$)	Constant Levelized Revenues ($/kWh in 2007$)	Constant Levelized after-tax O&M* Cost ($/kWh in 2007$)	Constant Levelized Capital Cost of manure to electricity ($/kWh in 2007$)
1	**Hilarides Dairy**	500.0	77.23%						
	covered lagoon								
	total			0.0636	0.0045	0.0591	0.0518	0.0037	0.0481
2	**Cottonwood (Gallo Cattle)**	300.0	81.17%						
	covered lagoon								
	total			0.3079	0.0434	0.2645	0.2511	0.0354	0.2157
3	**Meadowbrook Dairy**	160.0	78.52%						
	plug flow								
	total			0.2280	0.0271	0.2009	0.1859	0.0221	0.1638

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

Table A- 11 No Subsidy Carbon Credit and Bonus Depreciation Pipeline Quality Gas LCOE's for three plants

Engineering Assumptions and Cash Flow Results for carbon credit and 50% Bonus Depreciation sensitivity cases for "No Subsidy" pipeline quality gas.

	Dairy Name	Digester Size; Net Gas Prod'n (Mcf/day - inlet)	Plant Capacity Factor (%)	Nominal Levelized Gas Revenues ($/therm in 2007$)	Nominal Levelized after-tax O&M* Cost ($/therm in 2007$)	Nominal Levelized Capital Cost of manure to gas ($/therm in 2007$)	Constant Levelized Revenues ($/therm in 2007$)	Constant Levelized after-tax O&M* Cost ($/therm in 2007$)	Constant Levelized Capital Cost of manure to gas ($/therm in 2007$)
1	**Hilarides Dairy**	232.7	90.00%						
	covered lagoon	197.8							
	total			0.9953	0.0676	0.9277	0.8115	0.0551	0.7564
2	**Cottonwood (Gallo Cattle)**	113.0	90.00%						
	covered lagoon	96.0							
	total			4.4151	0.5106	3.9045	3.5996	0.4163	3.1833
3	**Meadowbrook**	80.5	90.00%						
	plug flow	68.4							
	total			2.8827	0.0949	2.7878	2.3502	0.0774	2.2728

* after-tax O&M is O&M multiplied by (1 - 40.75% combined tax rate) for all cases except IEUA, which is tax-free.

APPENDIX B – Two Financial Cash Flow Model Examples

B.1 - Hilarides Dairy – No-Subsidy Power

SUMMARY PAGE	0.5 MW Hilarides Dairy -- no subsidy	01/29/08	7:04 PM

Project Assumptions and Operating Results — File: CA_3n3Dairy_Biogas_d.xls

Cost Figures are in US dollars

Summary

Start Date		2006			
Project Description		Hilarides Dairy -- no subsidy			
		Lindsay CA, preliminary cash flow - may change.			
Finance		--			
Debt		0	at 7.00% for 12 years;		
Secondary Debt		0	at 8.50% for 10 years;		
Grants		0			
Equity		1,321,723			

Total		1,321,723			
Operations					
Herd employed		6,000	cows on	2,400	acres
Gross Rated Capacity		500	KW		
In-Plant Use		0.00%			
Net Rated Capacity		500	KW for sale		
Capacity Wholesale to Utility		500	KW		
Capacity Retail to Steam Host		0	KW		
Contract Term		20	years		
Inflation Rate		2.50%			
Actual Hours/Year		8,760	hours/year		
Outages	Forced	168.0	hours/year =	7.00	days/yr
	Planned	1,827.0	hours/year =	76.13	days/yr
Hours of Operation, after Outages		6,765	hours/year		
Capacity Factor, after Outages		77.23%			
Curtailment by Purchaser, on top		0.00%			
Total Net Plant Annual Electricity sold		3,382.500	thou kWh/year		
Total Net Plant Annual Electricity sold		9.2671	thou kWh/day	365	days/yr
Percentage Retail		0.00%	= 0.0 thou kWh/year	0.000	thou kWh/mo
Percentage Wholesale to Utility		100.00%	= 3,382.5 thou kWh/year	281.875	thou kWh/mo
				281.875	thou kWh/mo
Unfired Capacity Rate (mlb/hr)		0.00	mlb/hr		
Full Load Operating Hours		6,765	hours/year		
Unfired Capacity		0	mlb/yr =	0	gal/yr Propane
Auxiliary Fired Capacity Rate (mlb/hr)		0.0	mlb/hr		
Auxiliary Fired Hours Factor		100.00%			
Full Load Operating Hours		1,827	hours/year		
Auxiliary Fired Capacity		0	mlb/yr		
Boiler Capacity Rate (mlb/hr)		0.0	mlb/hr		
Full Load Operating Hours		0	hours/year		
Boiler Capacity		0	mlb/yr		
Electric Utility		SCE	select PG&E, SCE, SDG&E, other		

Capital Cost per netkW Installed capacity		$2,643	= 1,321,723 / 500		
Cost per annual kWh		$0.391	= 1,321,723 / 3,382,500		
Returns	--				
1 Pretax Unleveraged IRR		21.63%	, over	20	years
Net Present Value		1,418,380	, using	8.00%	discount rate
Payback		5	years		
2 Aftertax Leveraged IRR	target 17%	17.01%	, over	20	years
Net Present Value		319,256	, using	12.00%	discount rate
Payback		5	years		
Cost of Energy		in currency of 2006		in currency of 2007	
Power - Retail Host					
First year		$0.0000	/kWh	$0.0000	/kWh
Nominal levelized		$0.0000	/kWh	$0.0000	/kWh
Constant$ levelized		$0.0000	/kWh	$0.0000	/kWh
Power - Wholesale Utility					
First year		$0.0991	/kWh	$0.1016	/kWh
Nominal levelized		$0.0991	/kWh	$0.1016	/kWh
Constant$ levelized		$0.0808	/kWh	$0.0828	/kWh
Power - Total					
First year		$0.0991	/kWh	$0.1016	/kWh
Nominal levelized		$0.0991	/kWh	$0.1016	/kWh
Constant$ levelized		$0.0808	/kWh	$0.0828	/kWh
Operating Expense					
First year		$0.0037	/kWh	$0.0038	/kWh
Nominal levelized		$0.0044	/kWh	$0.0045	/kWh
Constant$ levelized		$0.0036	/kWh	$0.0037	/kWh
Steam - Retail Host					
First year		$0.00	$/mlb	$0.00	$/mlb
Nominal levelized		$0.00	$/mlb	$0.00	$/mlb
Constant$ levelized		$0.00	$/mlb	$0.00	$/mlb
Discount rate employed	8.500%	nominal			
	5.854%	constant (with no inflation)			
Debt Coverage Ratio		(operating income over debt payment)			
Senior Debt Coverage Ratio		0.000	minimum	target 1.20 times for balance sheet	
		0.000	average	target 1.40 times	
Secondary Debt Coverage Ratio		0.000	minimum		
		0.000	average		

ADDITIONAL INPUTS #1 **0.5 MW Hilarides Dairy -- no subsidy** **01/29/08** **7:04 PM**

Cost Figures are in US dollars

Uses of Funds

Manure Collection and Pretreatment		0		
Digester & Gas Production Enhancements		366,286		
Other		0		
Engine/Generator and Overhaul & Bldg		187,660		
Gas Transport & any Flare		66,659		
Gas Treatment		0		
Controls, Panels, Meters & Instrumentation		346,207		
Heat Recovery		0		
Gen'l Construction - Civil, Electrical, Transp		233,226		
System Design/Engineering		18,304		
Permits & Licenses		240		
Utility Interconnect		21,341		
Contingency/Other		0		
Sales Tax		0		
Subtotal	$2,479.8 /kW		1,239,923	*
Construction Financing	49,597		49,600	*
Construction Insurance			0	*
Other Overhead/Admin or Development Cost			0	*
Land			0	
First Year Start-up Funding			0	*
Debt Financing Fees	0		0	
(Legal costs, any commitment fee, amortized over debt life)				
Equity Financing Fees	19,826		19,800	
(Tax Advice, Equity Organizational Costs, etc.)				
Debt Service Reserve			0	
Working Capital Reserve	12,399		12,400	
Equipment Repair Reserve Initial Payment			0	
Other			0	*

Total			1,321,723	

Tax Information

Investment Tax Credit	0.00%	
Depreciation Tax Credit Deduction	50.00%	
(Usually 0.50; formerly 100% briefly.)		
Federal Income Tax Rate	35.00%	
State Income Tax Rate	8.84%	max corporate in California
Combined Tax Rate	40.75%	

Sources of Funds

0.000%	Debt	0	at 7.00% for 12 years;	Level Mortgage-style Payment
0.000%	Secondary Debt	0	at 8.50% for 10 years;	Level Mortgage-style Payment
0.000%	Grant	0		
0.000%	Second Grant	0		
100.000%	Equity	1,321,723		
-------------		--------------		
100.000%		1,321,723		

Depreciation

For method, select 1 as MACRS, 2 as straight-line, or 3 as customized depreciation.

Depreciation Method #1	1		
Depreciation Method #2	1		

For life, select 3, 5, 7, 10, 15, or 20 years for MACRS depreciation, or any year for straight-line.

Depreciation Class Life #1	5 years		Asset Class 01.21 - Cattle or Dairy - chk!
Depreciation Class Life #2	15 years		
Percent of base, depreciable as Class #1	100.00%		
Percent as Class #2	0.00% ok		ok
Use 50% Bonus Depr Class #1	1 Select 1 = no; 2 = yes.		50.0% Select 30% or 50%.
If MACRS, what year-1 Convention for Deprec #1?		0.5000	
For Depreciable Class Life #2?		0.5000	
Classification of Equity Financing Fees:	40.00% Tax Advice (expensed or 1 year);		
	0.00% Organizational Fees (5 years);		0.00% Misc. over Project Life;
			60.00% No write-off.

Tax Treatment

* Sum of depreciable Items, incl sales tax		1,289,523	
Primary System Depreciable Base			1,289,523
Tax Credit Adjustment		0	
Primary Base after tax credit adjustment		1,289,523	
Other Depreciable Base			0
First Year Start-up Funding fed to year 1			0
Land			0
Amortization over Debt's Life			
Amortization over 12 years	0.00%		0
Amortization over 10 years	100.00%		0
Amortization involving Equity			
Amortization over 1 years			7,920
Amortization over 5 years			0
Amortization over 20 years			0
No write-off			11,880
Reserves			
Debt Service Reserve			0
Working Capital Reserve			12,400
Equipment Repair Reserve Initial Payment			0

			1,321,723 ok

ADDITIONAL INPUTS #2 **0.5 MW Hilarides Dairy -- no subsidy** **01/29/08** **7:04 PM**

Cost Figures are in US dollars

Revenues and Fuel

Electric Revenues

Host Retail Energy Rate	6.0000	cents/kWh	
escalating at	2.50%		
degrading at	0.10%		
Host Demand Payment	0.0000	$/kW-capac/mo = $ 0.00/yr	
escalating at	1.50%		
Host Demand	0	thous kWh/yr	
Host Peak Demand	0	kW	
Utility Wholesale Energy Rate	9.9100	cents/kWh	
escalating at	0.00%		
degrading at	0.10%		
Utility Capacity Payment	0.0000	$/kW-capac/mo = $ 0.00/yr	
escalating at	1.50%		

Thermal & Other Revenues

Unfired Steam Price (var)	10.000	$/mlb =	--	$/gal
escalating at	2.50%			
Unfired Steam Price (fixed)	0	$ = about	0.000	$/mlb
escalating at	0.00%			
Auxiliary Fired Steam Price	10.000	$/mlb		
escalating at	2.50%			
Boiler Steam Price	8.000	$/mlb		
escalating at	2.50%			
Other - Carbon Credits	0	$/year		
escalating at	2.00%			

Fuel Expense Assumptions

Fuel #1 Rate	0.000	$/mmBtu =	0.000	$/Mcf
escalating at	2.50%			
Fuel #2 Rate	4.000	$/mmBtu		
escalating at	2.50%			

Unfired Fuel

		6,765	hours/year		
Total Consumption	per year	44,418.990	mmBtu/yr =	84,931.147	Mcf/yr
	per day @ 365 dy/yr	121.696	mmBtu/dy =	232.688	Mcf/dy
Fuel #1 Utilization Rate		100.00%			
Fuel #1 Consumption		6.5660	mmBtu/hr	= 6.57 / (1 - 0.00)	
degrading at		0.10%			
Plant Heat Rate		13,132	Btu/net kWh sold		
Fuel #2 Consumption		0.000	mmBtu/hr	= 0.00 / (1 - 0.10)	
degrading at		0.10%			

Dairy Cow Statistics

Herd	6,000	cows		
Unit Fuel	0.0203	mmBtu/cw/dy	0.0388	Mcf/cow/day

Auxiliary Fired Fuel

	1,827	hours/year	
Total Consumption	0	mmBtu/yr	
Fuel #1 Utilization Rate	100.00%		
Fuel #1 Consumption	0.000	mmBtu/hr	= 0.00 / (1 - 0.00)
Fuel #2 Consumption	0.000	mmBtu/hr	= 0.00 / (1 - 0.10)

Boiler Fuel

	0	hours/year	
Total Consumption	0	mmBtu/yr	
Fuel #1 Utilization Rate	100.00%		
Fuel #1 Consumption	0.000	mmBtu/hr	= 0.0 / (1 - 0.00)
Fuel #2 Consumption	0.000	mmBtu/hr	= 0.0 / (1 - 0.10)

Adjustments and Conversion Factors

Annual Heat Rate Increase		0.10%	
Fuel #1 Moisture factor		0.00%	
Fuel #2 Moisture factor		10.00%	
MM Btu / Mcf fuel #1	dairy manure	0.523000	
MM Btu / Mcf fuel #2	natural gas	1.020000	
Start Year		2006	
Heat Content propane		91,500	Btu/gal
Heat Content steam		1,000	Btu/lb

Other Expense Assumptions

Other		0.000	$/year	
escalating at		2.00%		
Standby Demand Payment		0.000	$/kW-capac/mo	
escalating at		2.50%		
Standby Energy Payment		0.000	cents/kWh	
escalating at		2.50%		
Host Standby Usage	ok	0	kW-capac	
for		0	months/year	
Other		0.000	$/kW-capac/mo	
escalating at		2.50%		
Service Cost		0.000	cents/kWh	
escalating at		2.50%		
assuming 100% availability and 100% run-time				
Operations & Maintenance		21,000	$/year	= $1,750/mo * 12.
escalating at		2.50%		
Operator		0	$/year	
escalating at		2.50%		
Administration/Compliance		0	$/year	
escalating at		2.50%		
Royalty		0.00%	% of revenues	
Adjustment Factor for prop tax, insur		100.00%		
Insurance		0.600%	% of adj. depreciable base	
escalating at		2.50%		
Property Tax		1.000%	% of adj. depreciable base	
escalating at		2.00%		
where base depreciates		4.00%	/year, till hits	30.00%
Deposit: Equipment Repair Reserve		0		
escalating at		2.50%		
Interest Earned on Reserves		3.00%		
Interest Earned on Working Capital Reserve		0.50%		
Year 1 Calendar Fraction		100.00%	usually 100%	
Factor with 2 debt payments per year		100.00%		

EARNINGS	**0.5 MW Hilarides Dairy -- no subsidy**								**01/29/08**	**7:04 PM**	
Cost Figures are in US dollars											
project year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
power sold wholesale (MWh/year)		3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50
power sold retail (MWh/year)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unfired Steam (mlb/year)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Auxfired Steam (mlb/year)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boiler Steam (mlb/year)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel #1 Consumed (mmBtu/yr)		44,419	44,463	44,508	44,552	44,597	44,642	44,686	44,731	44,776	44,820
Fuel #2 Consumed (mm Btu/yr)		0	0	0	0	0	0	0	0	0	0
Revenues											
Energy - wholesale		335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206
Capacity - wholesale		0	0	0	0	0	0	0	0	0	0
Energy - retail		0	0	0	0	0	0	0	0	0	0
Capacity - retail		0	0	0	0	0	0	0	0	0	0
Unfired Steam - variable		0	0	0	0	0	0	0	0	0	0
Unfired Steam - fixed		0	0	0	0	0	0	0	0	0	0
Auxfired Steam		0	0	0	0	0	0	0	0	0	0
Boiler Steam		0	0	0	0	0	0	0	0	0	0
Other - Carbon Credits		0	0	0	0	0	0	0	0	0	0
Total Revenues		335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206
Operating Costs											
Fuel #1 Costs		0	0	0	0	0	0	0	0	0	0
Fuel #2 Costs		0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Standby Demand Payment		0	0	0	0	0	0	0	0	0	0
Standby Energy Payment		0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Service Cost		0	0	0	0	0	0	0	0	0	0
Operations & Maintenance		21,000	21,525	22,063	22,615	23,180	23,760	24,354	24,962	25,586	26,226
Operator		0	0	0	0	0	0	0	0	0	0
Administration/Compliance		0	0	0	0	0	0	0	0	0	0
Royalty		0	0	0	0	0	0	0	0	0	0
Insurance		7,737	7,931	8,129	8,332	8,540	8,754	8,973	9,197	9,427	9,663
Property Tax		12,895	12,627	12,343	12,042	11,725	11,390	11,037	10,665	10,274	9,863
Total Operating Expenses		41,632	42,083	42,535	42,989	43,445	43,903	44,363	44,824	45,287	45,752
Operating Income		293,573	293,123	292,671	292,217	291,760	291,302	290,843	290,381	289,918	289,454
Interest Earned on Reserves		62	62	62	62	62	62	62	62	62	62
Interest - Loan #1		0	0	0	0	0	0	0	0	0	0
Interest - Loan #2		0	0	0	0	0	0	0	0	0	0
Income before Amortization/Depreciation		293,635	293,185	292,733	292,279	291,822	291,364	290,905	290,443	289,980	289,516
Amortization		7,920	0	0	0	0	0	0	0	0	0
Depreciation - Primary System		257,905	412,647	247,588	148,553	148,553	74,277	0	0	0	0
Depreciation - Secondary System		0	0	0	0	0	0	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Before-Tax Income		27,811	(119,462)	45,144	143,726	143,269	217,088	290,905	290,443	289,980	289,516
40.746% less: Income Tax Paid (Benefit Received)		11,332	(48,676)	18,395	58,562	58,377	88,455	118,532	118,344	118,155	117,966
Investment Tax Credit received		0	0	0							
Production Tax Credit received		0	0	0	0	0	0	0	0	0	0
After-Tax Income		16,479	(70,786)	26,750	85,163	84,893	128,633	172,373	172,099	171,825	171,550

EARNINGS **0.5 MW Hilarides Dairy -- no subsidy** **01/29/08** **7:04 PM**

Cost Figures are in US dollars

project year	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
power sold wholesale (MWh/year)	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	3,382.50	0.00	0.00
power sold retail (MWh/year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unfired Steam (mlb/year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Auxfired Steam (mlb/year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boiler Steam (mlb/year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel #1 Consumed (mmBtu/yr)	44,865	44,910	44,955	45,000	45,045	45,090	45,135	45,180	45,225	45,271	0	0
Fuel #2 Consumed (mm Btu/yr)	0	0	0	0	0	0	0	0	0	0	0	0
Revenues												
Energy - wholesale	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	0	0
Capacity - wholesale	0	0	0	0	0	0	0	0	0	0	0	0
Energy - retail	0	0	0	0	0	0	0	0	0	0	0	0
Capacity - retail	0	0	0	0	0	0	0	0	0	0	0	0
Unfired Steam - variable	0	0	0	0	0	0	0	0	0	0	0	0
Unfired Steam - fixed	0	0	0	0	0	0	0	0	0	0	0	0
Auxfired Steam	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Steam	0	0	0	0	0	0	0	0	0	0	0	0
Other - Carbon Credits	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	0	0
Operating Costs												
Fuel #1 Costs	0	0	0	0	0	0	0	0	0	0	0	0
Fuel #2 Costs	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0
Standby Demand Payment	0	0	0	0	0	0	0	0	0	0	0	0
Standby Energy Payment	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0
Service Cost	0	0	0	0	0	0	0	0	0	0	0	0
Operations & Maintenance	26,882	27,554	28,243	28,949	29,672	30,414	31,175	31,954	32,753	33,572	0	0
Operator	0	0	0	0	0	0	0	0	0	0	0	0
Administration/Compliance	0	0	0	0	0	0	0	0	0	0	0	0
Royalty	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	9,904	10,152	10,406	10,666	10,932	11,206	11,486	11,773	12,067	12,369	0	0
Property Tax	9,432	8,979	8,504	8,007	7,487	6,942	6,373	5,778	5,525	5,636	0	0
Total Operating Expenses	46,217	46,684	47,152	47,622	48,091	48,562	49,033	49,505	50,345	51,576	0	0
Operating Income	288,988	288,521	288,053	287,584	287,114	286,644	286,172	285,701	284,860	283,629	0	0
Interest Earned on Reserves	62	62	62	62	62	62	62	62	62	62	0	0
Interest - Loan #1	0	0	0	0	0	0	0	0	0	0	0	0
Interest - Loan #2	0	0	0	0	0	0	0	0	0	0	0	0
Income before Amortization/Depreciation	289,050	288,583	288,115	287,646	287,176	286,706	286,234	285,763	284,922	283,691	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation - Primary System	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation - Secondary System	0	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Income	289,050	288,583	288,115	287,646	287,176	286,706	286,234	285,763	284,922	283,691	0	0
40.746% less: Income Tax Paid (Benefit Received)	117,776	117,586	117,395	117,204	117,013	116,821	116,629	116,437	116,094	115,593	0	0
Investment Tax Credit received												
Production Tax Credit received	0	0	0	0	0	0	0	0	0	0	0	0
After-Tax Income	171,274	170,997	170,720	170,442	170,163	169,885	169,605	169,326	168,828	168,098	0	0

CASH FLOWS	**0.5 MW Hilarides Dairy -- no subsidy**								**01/29/08**	**7:04 PM**	

Cost Figures are in US dollars

project year year	**0** **2005**	**1** **2006**	**2** **2007**	**3** **2008**	**4** **2009**	**5** **2010**	**6** **2011**	**7** **2012**	**8** **2013**	**9** **2014**	**10** **2015**
Before-Tax Income		27,811	(119,462)	45,144	143,726	143,269	217,088	290,905	290,443	289,980	289,516
Add Back:											
First-year Start-up Funding		0	0	0	0	0					
Amortization		7,920	0	0	0	0	0	0	0	0	0
Depreciation		257,905	412,647	247,588	148,553	148,553	74,277	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Released from Reserves		0	0	0	0	0	0	0	0	0	0
Released from Major Maintenance Reserve		0	0	0	0	0	0	0	0	0	0
Other		0	0								
Total Additions		265,825	412,647	247,588	148,553	148,553	74,277	0	0	0	0
Subtract:											
Loan #1 Principal		0	0	0	0	0	0	0	0	0	0
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Deposit to Reserve		0	0	0	0	0	0	0	0	0	0
Charge for Capitalized Overhaul		0	0	0	0	0	0	0	0	0	0
Other		0	0								
Total Subtractions		0	0	0	0	0	0	0	0	0	0
Before-Tax Cash		293,635	293,185	292,733	292,279	291,822	291,364	290,905	290,443	289,980	289,516
Income Tax Paid (Benefit Received)		11,332	(48,676)	18,395	58,562	58,377	88,455	118,532	118,344	118,155	117,966
Investment Tax Credit Received		0	0	0							
Production Tax Credit Received		0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(1,321,723)	282,304	341,861	274,338	233,716	233,446	202,910	172,373	172,099	171,825	171,550

After-tax IRR 17.01% , using starting estimate of 10.00%

Net Present Value 319,256 , using discount rate of 12.00% for developer

Payback		5									
		1	1	1	1	1	0	0	0	0	0

GrantTotal 0 grant that need not be paid back.

CASH FLOWS | **0.5 MW Hilarides Dairy -- no subsidy** | **01/29/08** | **7:04 PM**

Cost Figures are in US dollars

project year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
year		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Before-Tax Income		289,050	288,583	288,115	287,646	287,176	286,706	286,234	285,763	284,922	283,691	0	0
Add Back:													
First-year Start-up Funding													
Amortization		0	0	0	0	0	0	0	0	0	0	0	0
Depreciation		0	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0	0	0
Released from Reserves		0	0	0	0	0	0	0	0	0	12,400	0	0
Released from Major Maintenance Reserve		0	0	0	0	0	0	0	0	0	0	0	0
Other													
Total Additions		0	0	0	0	0	0	0	0	0	12,400	0	0
Subtract:													
Loan #1 Principal		0	0	0	0	0	0	0	0	0	0	0	0
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0	0	0
Deposit to Reserve		0	0	0	0	0	0	0	0	0	0	0	0
Charge for Capitalized Overhaul		0	0	0	0	0	0	0	0	0	0	0	0
Other													
Total Subtractions		0	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash		289,050	288,583	288,115	287,646	287,176	286,706	286,234	285,763	284,922	296,091	0	0
Income Tax Paid (Benefit Received)		117,776	117,586	117,395	117,204	117,013	116,821	116,629	116,437	116,094	115,593	0	0
Investment Tax Credit Received													
Production Tax Credit Received		0	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(1,321,723)	171,274	170,997	170,720	170,442	170,163	169,885	169,605	169,326	168,828	180,498	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
GrantTotal													

COST OF ENERGY	**0.5 MW Hilarides Dairy -- no subsidy**	**01/29/08**	**7:04 PM**

Cost Figures are in US dollars		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Total Electric												
Total			335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206

3,382,500 kWh/year

Net Present Value	3,172,165	, using	8.500%	<--- SET THIS! Might try before-tax rate, from utility's cost of capital, for standardization across all cases and because utility is back-up source of power
Current $ Levelized	335,206	as Rate * NPV/(1-(1+Rate)^(-n))		
lev COE/kWh	$0.0991	in nominal terms of	2006	
lev COE/kWh	$0.1016	in nominal terms of	2007	
1st-yr Cost	$0.0991	in nominal terms of	2006	
1st-yr Cost	$0.1016	in nominal terms of	2007	
Constant $ NPV	3,172,165	, as nominal		
Constant $ Levelized	273,287	, using	5.854%	
lev COE/kWh	$0.0808	in constant terms of	2006	
lev COE/kWh	$0.0828	in constant terms of	2007	

		0	1	2	3	4	5	6	7	8	9	10
Operating Expenses	total O&M excl prop tax, insur		21,000	21,525	22,063	22,615	23,180	23,760	24,354	24,962	25,586	26,226
tax effect = O&M * (1-t)	adjusted total O&M		12,443	12,754	13,073	13,400	13,735	14,078	14,430	14,791	15,161	15,540
Total			12,443	12,754	13,073	13,400	13,735	14,078	14,430	14,791	15,161	15,540

3,382,500 kWh/year

Net Present Value	140,912	, using	8.500%	**Fixed Capital Cost**		
Current $ Levelized	14,890	as Rate * NPV/(1-(1+Rate)^(-n))		Calculated as Total less Op Exp.		
lev COE/kWh	$0.0044	in nominal terms of	2006	$0.0947	in nominal terms of	2006
lev COE/kWh	$0.0045	in nominal terms of	2007	$0.0971	in nominal terms of	2007
1st-yr Cost	$0.0037	in nominal terms of	2006	$0.0954	in nominal terms of	2006
1st-yr Cost	$0.0038	in nominal terms of	2007	$0.0978	in nominal terms of	2007
Constant $ NPV	140,912	, as nominal				
Constant $ Levelized	12,140	, using	5.854%			
lev COE/kWh	$0.0036	in constant terms of	2006	$0.0772	in constant terms of	2006
lev COE/kWh	$0.0037	in constant terms of	2007	$0.0791	in constant terms of	2007

COST OF ENERGY **0.5 MW Hilarides Dairy -- no subsidy** 01/29/08 7:04 PM

Cost Figures are in US dollars		11	12	13	14	15	16	17	18	19	20	21	22
Total Electric													
Total		335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	335,206	0	0
3,382,500	kWh/year												
			*To figure Discount rate:			Utility tax rate	40.00%						
				Utility debt	50.00%	6.50%							
				preferred	5.00%	6.30%							
				common	45.00%	11.00%							
						8.52%	before-tax weighted average cost of capital						
				Utility debt	50.00%	60.00%	6.50%	'by (1 - utility combined tax rate)					
				preferred	5.00%		6.30%						
				common	45.00%		11.00%						
							7.22%	after-tax weighted average cost of capital					
Operating Expenses	total O&M excl	26,882	27,554	28,243	28,949	29,672	30,414	31,175	31,954	32,753	33,572	0	0
tax effect = O&M * (1-t)	adjusted total C	15,929	16,327	16,735	17,153	17,582	18,022	18,472	18,934	19,407	19,893	0	0
Total		15,929	16,327	16,735	17,153	17,582	18,022	18,472	18,934	19,407	19,893	0	0
3,382,500	kWh/year												

B.2 - Hilarides Dairy – No-Subsidy Pipeline-Quality Gas

SUMMARY PAGE **198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy** **02/22/08** **6:44 PM**

Project Assumptions and Operating Results **File: CA_3n4_gas_Dairy_Biogas_dd.xls**

Cost Figures are in US dollars

Summary

Start Date	2006	
Project Description	Hilarides Dairy - Pipeline-Quality Gas -- no subsidy	
	Lindsay CA, preliminary cash flow - may change.	

Finance --

Debt	0	at 7.00% for 12 years;
Secondary Debt	0	at 8.50% for 10 years;
Grants	0	
Equity	1,568,589	

Total	1,568,589	

Operations

Herd employed		6,000	cows on	2,400	acres
Lactating Cows employed		6,000	cows		
Digester Gas Production		232.681	Mcf/day (inlet)		
Processing Losses		-15.00%			
Gross Sustainable Gas Production		197.779	Mcf/day (inlet)		
In-Plant Use		0.00%			
Net Sustainable Gas Production		197.779	Mcf/day for sale (inlet)		
Net Fuel Output (MM Btu)		103.438	mm Btu/day for sale		
Capacity Wholesale to Utility		103.438	mm Btu/day		
Contract Term		20	years		
Inflation Rate		2.50%			
Actual Hours/Year		8,760	hours/year		
Outages	Forced	276.0	hours/year =	11.50	days/yr
	Planned	600.0	hours/year =	25.00	days/yr
Hours of Operation, after Outages		7,884	hours/year		
Capacity Factor, after Outages		90.00%			
Curtailment by Purchaser, on top		0.00%			
Total Net Plant Annual Gas sold		33,979.5	mm Btu/year		
Total Net Plant Annual Gas sold		93.1	mm Btu/day	365	days/yr
MM Btu / Mcf fuel #1	dairy manure	0.5230			
MM Btu / Mcf fuel #2	natural gas	1.0200			
Total Net Plant Annual Gas sold		33,313.2	Mcf/year (outlet)		
Total Net Plant Annual Gas sold		91.3	Mcf/day (outlet)		
Electric Utility		SCE	select PG&E, SCE, SDG&E, other		

Capital Cost per mm cubic ft/day (inlet)	$7,931,025	= 1,568,589 / 0.198
Cost per annual Mcf (outlet)	$47.09	= 1,568,589 / 33,313

Returns --

1 Pretax Unleveraged IRR		21.64% , over	20	years
Net Present Value		1,679,507 , using	8.00%	discount rate
Payback		5 years		
2 Aftertax Leveraged IRR	target 17%	17.01% , over	20	years
Net Present Value		377,984 , using	12.00%	discount rate
Payback		5 years		

Cost of Energy

	in currency of 2006	in currency of 2007
Gas - Wholesale Utility		
First year	$1.2148 /therm	$1.2452 /therm
Nominal levelized	$1.2148 /therm	$1.2452 /therm
Constant$ levelized	$0.9904 /therm	$1.0152 /therm
Operating Expense		
First year	$0.0551 /therm	$0.0565 /therm
Nominal levelized	$0.0660 /therm	$0.0676 /therm
Constant$ levelized	$0.0538 /therm	$0.0551 /therm

Discount rate employed	8.500%	nominal
	5.854%	constant (with no inflation)

Debt Coverage Ratio (operating income over debt payment)

Senior Debt Coverage Ratio	0.000 minimum	target 1.20 times for balance sheet
	0.000 average	target 1.40 times
Secondary Debt Coverage Ratio	0.000 minimum	
	0.000 average	

ADDITIONAL INPUTS #1 **198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy** 02/22/08 6:44 PM

Cost Figures are in US dollars

Uses of Funds

Manure Collection and Pretreatment		0		
Digester & Gas Production Enhancements		366,286		
Other		0		
Engine/Generator and Overhaul & Bldg		0	delete for gas	
Gas Transport & any Flare		66,659		
Gas Treatment		0		
Controls, Panels, Meters & Instrumentation		0	delete for gas	
Heat Recovery		0		
Gen'l Construction - Civil, Electrical, Transp		0	delete for gas	
System Design/Engineering		18,304		
Permits & Licenses		240		
Electric Utility Interconnect		0	delete for gas	
Land, for pipeline interconnect		0		
Pipeline, Tap, Controls, Unique Facilities		160,000		
Gas Cleanup & Processing		720,000		
SCADA monitoring		90,000		
Leachate Monitoring System		0		
Double Lagoon Liner & Lagoon Cover		0		
Contingency/Other		0		
Pipeline		50,000		
Subtotal	$7,440,073	mm cf/day (inle	1,471,489	*
Construction Financing	58,860		58,900	*
Construction Insurance			0	*
Other Overhead/Admin or Development Cost			0	*
Land			0	
First Year Start-up Funding			0	
Debt Financing Fees	0		0	
(Legal costs, any commitment fee, amortized over debt life)				
Equity Financing Fees	23,529		23,500	
(Tax Advice, Equity Organizational Costs, etc.)				
Debt Service Reserve			0	
Working Capital Reserve	14,715		14,700	
Equipment Repair Reserve Initial Payment			0	
Other			0	*

Total			1,568,589	

Tax Information

Investment Tax Credit	0.00%	
Depreciation Tax Credit Deduction	50.00%	
(Usually 0.50; formerly 100% briefly.)		
Federal Income Tax Rate	35.00%	
State Income Tax Rate	8.84%	max corporate in California
Combined Tax Rate	40.75%	

Sources of Funds

0.000%	Debt	0	at 7.00% for 12 years;	Level Mortgage-style Payment
0.000%	Secondary Debt	0	at 8.50% for 10 years;	Level Mortgage-style Payment
0.000%	Grant	0		
0.000%	Second Grant	0		
100.000%	Equity	1,568,589		
-------------		---------------		
100.000%		1,568,589		

*

Depreciation

For method, select 1 as MACRS, 2 as straight-line, or 3 as customized depreciation.

Depreciation Method #1	1		
Depreciation Method #2	1		

For life, select 3, 5, 7, 10, 15, or 20 years for MACRS depreciation, or any year for straight-line.

Depreciation Class Life #1	5 years		Asset Class 01.21 - Cattle or Dairy - chk!
Depreciation Class Life #2	15 years		
Percent of base, depreciable as Class #1	100.00%		
Percent as Class #2	0.00% ok		ok
Use 50% Bonus Depr Class #	1 Select 1 = no; 2 = yes.		50.0% Select 30% or 50%.
If MACRS, what year-1 Convention for Deprec #1?		0.5000	
For Depreciable Class Life #2?		0.5000	
Classification of Equity Financing Fees:	40.00% Tax Advice (expensed or 1 year);		
0.00% Organizational Fees (5 years);		0.00% Misc. over Project Life;	
		60.00% No write-off.	

Tax Treatment

Sum of depreciable Items, incl sales tax		1,530,389	
Primary System Depreciable Base			1,530,389
Tax Credit Adjustment		0	
Primary Base after tax credit adjustment		1,530,389	
Other Depreciable Base			0
First Year Start-up Funding fed to year 1			0
Land			0
Amortization over Debt's Life			
Amortization over 12 years	0.00%		0
Amortization over 10 years	100.00%		0
Amortization involving Equity			
Amortization over 1 years			9,400
Amortization over 5 years			0
Amortization over 20 years			0
No write-off			14,100
Reserves			
Debt Service Reserve			0
Working Capital Reserve			14,700
Equipment Repair Reserve Initial Payment			0

			1,568,589 ok

ADDITIONAL INPUTS #2 **198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy** **02/22/08** **6:44 PM**

Cost Figures are in US dollars

Revenues and Fuel

Gas Revenues

Utility Wholesale Energy Rate	11.9100	$/mmBtu		
escalating at	0.00%			
degrading at	0.00%			
Utility Capacity Payment	0.0000	$/mmBtu		
escalating at	1.50%			

Other Revenues

Other - Byproduct	0	$/year
escalating at	2.50%	
Other - Carbon Credits	0	$/year
escalating at	2.00%	

Fuel Expense Assumptions

Fuel #1 Rate	0.000	$/mmBtu =	0.000	$/Mcf
escalating at	2.50%			
Fuel #2 Rate	4.000	$/mmBtu		
escalating at	2.50%			

Unfired Fuel 7,884 hours/year

Total Consumption	per year	44,417.6	mmBtu/yr =	84,928.6	Mcf/yr (inlet)
	per day @ 365 dy/yr	121.7	mmBtu/dy =	232.7	Mcf/dy (inlet)
Fuel #1 Utilization Rate		100.00%			
Fuel #1 Consumption		5.6339	mmBtu/hr	= 5.63 / (1 - 0.00)	
degrading at		0.00%			
Plant Heat Rate		1.30719	Btu in /Btu sold		
Fuel #2 Consumption		0.000	mmBtu/hr	= 0.00 / (1 - 0.10)	
degrading at		0.00%			
Processing Loss		-15.00%	percentage gas lost in upgrading and cleaning		

Dairy Cow Statistics

Herd	6,000	cows		
Lactating Cows	6,000	cows		
Unit Fuel	0.0203	mmBtu/lac-cw	0.0388	Mcf/lac-cow/day

Adjustments and Conversion Factors

Annual Heat Rate Increase		0.00%	note: 0.0% for gas; 0.10% for power.	
Fuel #1 Moisure factor		0.00%		
Fuel #2 Moisure factor		10.00%		
MM Btu / Mcf fuel #1	dairy manure	0.523000		
MM Btu / Mcf fuel #2	natural gas	1.020000		
Start Year		2006		
Heat Content propane		91,500	Btu/gal	
Heat Content steam		1,000	Btu/lb	

Other Expense Assumptions

Gas Monitoring		10,000	$/year	
escalating at		2.50%		
Standby Demand Payment		0.000	$/kW-capac/mo	
escalating at		2.50%		
Standby Energy Payment		0.000	cents/kWh	
escalating at		2.50%		
Host Standby Usage	ok	0	kW-capac	
for		0	months/year	
Other		0.000	$/kW-capac/mo	
escalating at		2.50%		
Service Cost		0.000	cents/kWh	
escalating at		2.50%		
assuming 100% availability and 100% run-time				
Operations & Maintenance		21,000	$/year	= $1,750/mo * 12.
escalating at		2.50%		
Operator		0	$/year	
escalating at		2.50%		
Leachate Monitoring		0	$/year	
escalating at		2.50%		
Royalty		0.00%	% of revenues	
Adjustment Factor for prop tax, insur		100.00%		
Insurance		0.600%	% of adj. depreciable base	
escalating at		2.50%		
Property Tax		1.000%	% of adj. depreciable base	
escalating at		2.00%		
where base depreciates		4.00%	/year, till hits	30.00%
Deposit: Equipment Repair Reserve		0		
escalating at		2.50%		
Interest Earned on Reserves		3.00%		
Interest Earned on Working Capital Reserve		0.50%		
Year 1 Calendar Fraction		100.00%	usually 100%	
Factor with 2 debt payments per year		100.00%		

EARNINGS **198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy** **02/22/08** **6:44 PM**

Cost Figures are in US dollars

project year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
gas sold wholesale (mm Btu/year)		33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5
Fuel #1 Consumed (mmBtu/yr)		44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6
Fuel #2 Consumed (mm Btu/yr)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenues											
Energy - wholesale		404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696
Capacity - wholesale		0	0	0	0	0	0	0	0	0	0
Other Byproduct		0	0	0	0	0	0	0	0	0	0
Other - Carbon Credits		0	0	0	0	0	0	0	0	0	0
Total Revenues		404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696
Operating Costs											
Fuel #1 Costs		0	0	0	0	0	0	0	0	0	0
Fuel #2 Costs		0	0	0	0	0	0	0	0	0	0
Gas Monitoring		10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489
Standby Demand Payment		0	0	0	0	0	0	0	0	0	0
Standby Energy Payment		0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Service Cost		0	0	0	0	0	0	0	0	0	0
Operations & Maintenance		21,000	21,525	22,063	22,615	23,180	23,760	24,354	24,962	25,586	26,226
Operator		0	0	0	0	0	0	0	0	0	0
Leachate Monitoring		0	0	0	0	0	0	0	0	0	0
Royalty		0	0	0	0	0	0	0	0	0	0
Insurance		9,182	9,412	9,647	9,888	10,136	10,389	10,649	10,915	11,188	11,467
Property Tax		15,304	14,986	14,648	14,292	13,915	13,517	13,098	12,657	12,193	11,705
Total Operating Expenses		55,486	56,172	56,865	57,564	58,269	58,980	59,698	60,421	61,151	61,888
Operating Income		349,210	348,523	347,831	347,132	346,427	345,716	344,998	344,274	343,544	342,808
Interest Earned on Reserves		74	74	74	74	74	74	74	74	74	74
Interest - Loan #1		0	0	0	0	0	0	0	0	0	0
Interest - Loan #2		0	0	0	0	0	0	0	0	0	0
Income before Amortization/Depreciation		349,283	348,597	347,904	347,206	346,501	345,789	345,072	344,348	343,618	342,882
Amortization		9,400	0	0	0	0	0	0	0	0	0
Depreciation - Primary System		306,078	489,724	293,835	176,301	176,301	88,150	0	0	0	0
Depreciation - Secondary System		0	0	0	0	0	0	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Before-Tax Income		33,805	(141,128)	54,070	170,905	170,200	257,639	345,072	344,348	343,618	342,882
40.746% less: Income Tax Paid (Benefit Received)		13,774	(57,504)	22,031	69,637	69,350	104,978	140,603	140,308	140,011	139,711
Investment Tax Credit received		0	0	0							
Production Tax Credit received		0	0	0	0	0	0	0	0	0	0
After-Tax Income		20,031	(83,624)	32,038	101,268	100,850	152,661	204,469	204,040	203,607	203,171

EARNINGS

198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy **02/22/08** **6:44 PM**

Cost Figures are in US dollars

project year	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
gas sold wholesale (mm Btu/year)	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	33,979.5	0.0	0.0
Fuel #1 Consumed (mmBtu/yr)	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	44,417.6	0.0	0.0
Fuel #2 Consumed (mm Btu/yr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenues												
Energy - wholesale	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	0	0
Capacity - wholesale	0	0	0	0	0	0	0	0	0	0	0	0
Other Byproduct	0	0	0	0	0	0	0	0	0	0	0	0
Other - Carbon Credits	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	0	0
Operating Costs												
Fuel #1 Costs	0	0	0	0	0	0	0	0	0	0	0	0
Fuel #2 Costs	0	0	0	0	0	0	0	0	0	0	0	0
Gas Monitoring	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987	0	0
Standby Demand Payment	0	0	0	0	0	0	0	0	0	0	0	0
Standby Energy Payment	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0
Service Cost	0	0	0	0	0	0	0	0	0	0	0	0
Operations & Maintenance	26,882	27,554	28,243	28,949	29,672	30,414	31,175	31,954	32,753	33,572	0	0
Operator	0	0	0	0	0	0	0	0	0	0	0	0
Leachate Monitoring	0	0	0	0	0	0	0	0	0	0	0	0
Royalty	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	11,754	12,048	12,349	12,658	12,974	13,299	13,631	13,972	14,321	14,679	0	0
Property Tax	11,193	10,656	10,093	9,503	8,885	8,239	7,563	6,857	6,557	6,688	0	0
Total Operating Expenses	62,630	63,379	64,133	64,894	65,662	66,435	67,214	67,999	69,228	70,926	0	0
Operating Income	342,066	341,317	340,562	339,801	339,034	338,261	337,482	336,696	335,468	333,770	0	0
Interest Earned on Reserves	74	74	74	74	74	74	74	74	74	74	0	0
Interest - Loan #1	0	0	0	0	0	0	0	0	0	0	0	0
Interest - Loan #2	0	0	0	0	0	0	0	0	0	0	0	0
Income before Amortization/Depreciation	342,139	341,391	340,636	339,875	339,108	338,334	337,555	336,770	335,541	333,843	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation - Primary System	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation - Secondary System	0	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Income	342,139	341,391	340,636	339,875	339,108	338,334	337,555	336,770	335,541	333,843	0	0
40.746% less: Income Tax Paid (Benefit Received)	139,408	139,103	138,795	138,485	138,173	137,858	137,540	137,220	136,720	136,028	0	0
Investment Tax Credit received												
Production Tax Credit received	0	0	0	0	0	0	0	0	0	0	0	0
After-Tax Income	202,731	202,288	201,840	201,389	200,935	200,477	200,015	199,550	198,822	197,816	0	0

CASH FLOWS

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Cost Figures are in US dollars

	0	1	2	3	4	5	6	7	8	9	10
project year / year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Before-Tax Income		33,805	(141,128)	54,070	170,905	170,200	257,639	345,072	344,348	343,618	342,882
Add Back:											
First-year Start-up Funding		0	0	0	0	0					
Amortization		9,400	0	0	0	0	0	0	0	0	0
Depreciation		306,078	489,724	293,835	176,301	176,301	88,150	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Released from Reserves		0	0	0	0	0	0	0	0	0	0
Released from Major Maintenance Reserve		0	0	0	0	0	0	0	0	0	0
Other		0	0								
Total Additions		315,478	489,724	293,835	176,301	176,301	88,150	0	0	0	0
Subtract:											
Loan #1 Principal		0	0	0	0	0	0	0	0	0	0
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Deposit to Reserve		0	0	0	0	0	0	0	0	0	0
Charge for Capitalized Overhaul		0	0	0	0	0	0	0	0	0	0
Other		0	0								
Total Subtractions		0	0	0	0	0	0	0	0	0	0
Before-Tax Cash		349,283	348,597	347,904	347,206	346,501	345,789	345,072	344,348	343,618	342,882
Income Tax Paid (Benefit Received)		13,774	(57,504)	22,031	69,637	69,350	104,978	140,603	140,308	140,011	139,711
Investment Tax Credit Received		0	0	0							
Production Tax Credit Received		0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(1,568,589)	335,509	406,101	325,873	277,569	277,151	240,812	204,469	204,040	203,607	203,171

After-tax IRR 17.01% , using starting estimate of 10.00%

Net Present Value 377,984 , using discount rate of 12.00% for developer

Payback		5									
		1	1	1	1	1	0	0	0	0	0

GrantTotal 0 grant that need not be paid back. For Hilarides, California DPPP providded a grant of $500,000.

CASH FLOWS

198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy **02/22/08** **6:44 PM**

Cost Figures are in US dollars

project year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
year		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Before-Tax Income		342,139	341,391	340,636	339,875	339,108	338,334	337,555	336,770	335,541	333,843	0	0
Add Back:													
First-year Start-up Funding													
Amortization		0	0	0	0	0	0	0	0	0	0	0	0
Depreciation		0	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0	0	0
Released from Reserves		0	0	0	0	0	0	0	0	0	14,700	0	0
Released from Major Maintenance Reserve		0	0	0	0	0	0	0	0	0	0	0	0
Other													
Total Additions		0	0	0	0	0	0	0	0	0	14,700	0	0
Subtract:													
Loan #1 Principal		0	0	0	0	0	0	0	0	0	0	0	0
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0	0	0
Deposit to Reserve		0	0	0	0	0	0	0	0	0	0	0	0
Charge for Capitalized Overhaul		0	0	0	0	0	0	0	0	0	0	0	0
Other													
Total Subtractions		0	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash		342,139	341,391	340,636	339,875	339,108	338,334	337,555	336,770	335,541	348,543	0	0
Income Tax Paid (Benefit Received)		139,408	139,103	138,795	138,485	138,173	137,858	137,540	137,220	136,720	136,028	0	0
Investment Tax Credit Received													
Production Tax Credit Received		0	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(1,568,589)	202,731	202,288	201,840	201,389	200,935	200,477	200,015	199,550	198,822	212,516	0	0
		0	0	0	0	0	0	0	0	0	0	0	0
GrantTotal													

COST OF ENERGY **198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy** **02/22/08** **6:44 PM**

Cost Figures are in US dollars

		0	1	2	3	4	5	6	7	8	9	10
project year		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
year		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wholesale Utility Electric	Cal fraction		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Energy		404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696
	Capacity		0	0	0	0	0	0	0	0	0	0
Total			404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696

33,979.5	mm Btu/year					
1.020	MM Btu / Mcf fu	Net Present Value	3,829,772	, using	8.500%	<--- SET THIS! Might try before-tax rate, from utility's cost of capital
33,313.2	Mcf/year	Current $ Levelized	404,696	as Rate * NPV/(1-(1+Rate)^(-n))		
333,132.3	therms/year					
		lev COE/therm	$1.2148	in nominal terms of	2006	
		lev COE/therm	$1.2452	in nominal terms of	2007	
		1st-yr Cost	$1.2148	in nominal terms of	2006	
		1st-yr Cost	$1.2452	in nominal terms of	2007	
		Constant $ NPV	3,829,772	, as nominal		
		Constant $ Levelized	329,941	, using	5.854%	=(1+ 0.085)/(1+ 0.025) - 1
		lev COE/therm	$0.9904	in constant terms of	2006	
		lev COE/therm	$1.0152	in constant terms of	2007	

07/11/2007 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

		0	1	2	3	4	5	6	7	8	9	10
Operating Expenses	total O&M excl prop tax, insur		31,000	31,775	32,569	33,384	34,218	35,074	35,950	36,849	37,770	38,715
tax effect = O&M * (1-t)	adjusted total O&M		18,369	18,828	19,299	19,781	20,276	20,783	21,302	21,835	22,381	22,940
Total			18,369	18,828	19,299	19,781	20,276	20,783	21,302	21,835	22,381	22,940

33,979.5	mm Btu/year								
		Net Present Value	208,014	, using	8.500%	**Fixed Capital Cost**			
333,132.3	therms/year	Current $ Levelized	21,981	as Rate * NPV/(1-(1+Rate)^(-n))		Calculated as Total less Op Exp.			
		lev COE/therm	$0.0660	in nominal terms of	2006		$1.1488	in nominal terms of	2006
		lev COE/therm	$0.0676	in nominal terms of	2007		$1.1776	in nominal terms of	2007
		1st-yr Cost	$0.0551	in nominal terms of	2006		$1.1597	in nominal terms of	2006
		1st-yr Cost	$0.0565	in nominal terms of	2007		$1.1887	in nominal terms of	2007
		Constant $ NPV	208,014	, as nominal					
		Constant $ Levelized	17,921	, using	5.854%				
		lev COE/therm	$0.0538	in constant terms of	2006		$0.9366	in constant terms of	2006
		lev COE/therm	$0.0551	in constant terms of	2007		$0.9600	in constant terms of	2007

COST OF ENERGY **198 Mcf/dy Hilarides Dairy - Pipeline-Quality Gas -- no subsidy** **02/22/08** **6:44 PM**

Cost Figures are in US dollars

project year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
year		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Wholesale Utility Electric	Cal fraction	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.000
	Energy	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	0	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0	0
Total		404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	404,696	0	0

33,979.5	mm Btu/year					
1.020	MM Btu / Mcf fuel #2	*To figure Discount rate:		Utility tax rate	40.00%	
33,313.2	Mcf/year					
333,132.3	therms/year	Utility debt	50.00%	6.50%		
		preferred	5.00%	6.30%		
		common	45.00%	11.00%		
				8.52%	before-tax weighted average cost of capital	
		Utility debt	50.00%	60.00%	6.50%	'by (1 - utility combined tax rate)
		preferred	5.00%		6.30%	
		common	45.00%		11.00%	
					7.22%	after-tax weighted average cost of capital

Operating Expenses	total O&M excl	39,683	40,675	41,692	42,734	43,802	44,897	46,020	47,170	48,349	49,558	0	0
tax effect = O&M * (1-t)	adjusted total C	23,514	24,101	24,704	25,322	25,955	26,603	27,268	27,950	28,649	29,365	0	0
Total		23,514	24,101	24,704	25,322	25,955	26,603	27,268	27,950	28,649	29,365	0	0

33,979.5 mm Btu/year

333,132.3 therms/year

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