Anaerobic Digestion in California Dairies:

Electricty Generation or Biomethane Upgrading

An economic study on five California Dairy Farms

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Göteborg, Sweden 2006/2008

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Acknowledgements

I would like to thank:

Dr. Tim Lipman for giving me the chance to experience the amazing environment of the University of California at Berkeley and for his support in defining the orientation of this study.

Eng. Kenneth Brennan from PG&E for all the time he dedicated to clarify me the biomethane upgrading technology and the contractual terms between farmers and utilities.

Mr. Allen Dusault from the Sustainable Conservation for his support in creating the contacts with Californian dairy farmers, and Mrs. LaMendola from the Western United Dairymen for all the valuable information on the previous dairy farm biogas projects.

Professor Göran Berndes from Chalmers Tekniska Högskola for his sustain in the project and for an incredible amenability and professionalism in all the phases of this journey.

These people have been extremely kind in spending their personal time to assist me in my work and for this, I sincerely thank them.

Abstract

California is worldwide one of the major Green House Gas emitter due to a large use of fossil fuels in power generation and transportation. The dairy sector can play an important role in reducing these pollutants through the installation of anaerobic digesters and the production of biogas. This study has analyzed the two productive options, biomethane upgrading and on-site electricity generation that a dairy farmer can consider after installing an anaerobic digestion system. The two options have been applied to five California dairy farms with diverse productive, geographical and size conditions in order to identify the best applicable technology for the sector. Both the options have been proved in three modified scenarios in order to identify under which conditions each can achieve the best economical results. Biogas yield efficiency and reduction in capital costs appeared binding conditions in both cases even though electricity generation seemed more solid on average even with lower yields. Biomethane upgrading resulted the preferable path for large size farms or for associations of farmers intentioned to adhere and produce biomethane jointly. Electricity generation instead can guarantee better payback periods to small family-size farms due to lower investment costs. Last the study shows the necessity of dedicate policies to support both options in order to allow the development of the technologies in this sector.

Key words: Dairy Farms, Biogas, Biomethane Upgrading, Electricity Generation, Anaerobic Digestion, Biomass.

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Goals and Objective of the study

The final aim of this study is to compare from an economic and environmental point of view the performances of two different options available for California dairy farms with an anaerobic digestion system. On-site electricity generation and biomethane upgrading are the two renewable energy production options that will be considered.

This analysis includes all investment and running costs that five chosen California farms will have to face in order to develop the two technologies on their properties.

The different alternatives considered will then be compared in relation to their forecasted payback periods.

Through an overview of the various California Green House Gas emissions (main sources and sinks), the reader will be informed of the possibilities of reduction connected with an improved use of biomass. Furthermore California environmental public policy will be discussed and analyzed, especially when directly linked with the use of biomass and renewable energy, to identify necessary improvements and recommendations.

In addition California energy market will be presented in order to clarify the circumstances in which these technologies will be compared by customers and investor owned utilities (IOUs).

The California dairy sector will then be explored to identify its connections to GHG emissions and the possibilities to reduce its environmental footprint.

Moreover the available contracts between farmers producing energy (both electricity and biomethane) and IOUs will be described in order to identify possible improvements.

The report will then analyze and discuss five case studies with different productivity and geographical characteristics. The purpose of choosing of five diverse productive realities is to offer a more objective comparison relying as less as possible on site specific factors.

The assumptions for this project include a hypothetical levelized environmental benefit regardless of site-specific conditions.

This study will evaluate two main energy production options:

A. Electricity generation. Energy is generated using small engine generators fueled by unclean biogas obtained from cow manure digestion.

B. Biomethane upgrading. Biogas is obtained by anaerobic digestion and first purified and then sold to the Utility Owner that uses it as natural gas.

The five farms analyzed within this study are currently operating electric generation engines fueled by biogas. When these systems were installed, however biomethane upgrading was not yet an available option on the market because IOUs had no interest in purchasing the gas.

The report will offer six analyses for each of the five dairies observed and will compare the results in order to define the best available technologies within different policy and both contractual and productive hypotheses.

The six scenarios will include:

1. Electricity scenario 1, including actual amount of flared biogas and system efficiencies as reported by the farmers in the August of 2006.

This first case will assess on-site electricity production and the NEMBIO agreement with the IOUs (no extra power produced and put into the grid create additional revenues to the farmers).

2. Electricity Scenario 2. This second evaluation will stress the actual system trying to identify the payback periods once:

 a. Extra power produced by the farmers is acquired by IOUs for 7 cents/kWh

 b. Biogas flaring is reduced to zero. At the moment there are no incentives to the farmers for an efficient use of their biogas. Once the electricity produced is equal to the electricity demand of the dairy, many farms opt for flaring the excess biogas.

3. Electricity Scenario 3.

 a. Extra power produced by the farmers is acquired by IOUs for 7 cents/kWh

b. Maximum biogas yield for each farm is calculated hypothesizing 60 cf per cow per day of biogas. This option requires in some cases to increase the generation system installed in order to handle the additional inflow.

4. Biomethane, Scenario 4.

a. This alternative will utilize the same productive data of scenario 2, but instead than using for power generation the biogas is upgraded to biomethane.

b. IOUs are estimated to pay a value of $6 per MM Btu to farmers for the biomethane.

5. Biomethane, Scenario 5.

a. This alternative will utilize the same productive data of scenario 3, but instead than using for power generation the biogas is upgraded to biomethane.

b. IOUs are estimated to pay a value of $6 per MM Btu to farmers for the biomethane.

6. Biomethane, Scenario 6.

a. This alternative will utilize potential yield as estimated by PERI data (90 cubic feet/day/cow).

b. IOUs are estimated to pay a value of $7 per MM Btu to farmers for the biomethane.

Scope of Work

Step One: Obtain Data – During this step relevant data for the five dairies have been gathered and filtered. Particularly helpful has been the "Dairy Methane Digester System Program Evaluation Report" by Western United Resource Development Inc. from which all productive data was obtained for the base case scenario [30].

Western United Resource Development Inc was designated in 2004 by California Energy Commission (CEC) to advertise, review, and select those dairies eligible for funding to install anaerobic digesters and energy generators.

Only five of all the ten projects that obtained grants have been selected for this study. The diversity of the five candidates, however, has been able to produce interesting findings on a diversity of issues and has offered interesting ideas for improvements addressed to a wide range of productive realities.

The buy-down grants provided by CEC offered farmers two different incentive options:

a. Half the capital costs of the equipment (not over 2000$/kWh)

b. An incentive for the installation of the equipment in proportion of kW installed

The calculations are based on the following information obtained by the collection of data:

a. Specific system characteristics

b. Volume of biogas generated and performance parameters of the conversion system (heat rate, energy ratio inflow-outflow)

c. Historical data for electricity generation and historical data for electricity demand

d. Capital costs for equipment, operating costs for both the typologies of equipments

Princeton Energy Resources International (PERI) has represented another fundamental source of information that has been valuable in assessing investment costs of biomethane upgrading systems, and to run a sensitivity analysis of the findings of this report.

Expected costs for equipment (biogas upgrading, injection system, monitoring, etc.), operating costs for the biomethane production are the result of market research activity, consultation with sector experts from the Dairymen Association and University, as well as feedback from PG&E gas department experts.

The calculations have been realized first by considering the same productive data and specific characteristics indicated in the study by WURDCO, and second by hypothesizing variations to these data, especially in terms of biogas conversion efficiency and biogas yield, so that the report will offer indications for improvements for diverse kind of candidates (farms).

Step Two: Calculation of the different options – The result of this step will put the base for a clear comparison between the electricity and pipeline quality gas and utilizing data previously gathered.

Calculations Methodology

Grants and subsidies represent an indispensable factor for the realization of an AD system. Many observers have debated on the real economical sustainability of AD power production in absence of financial support. The study offered by WURDCO has shown that most of the projects realized under the DPP program would have resulted in payback periods double the actual ones.

In order to obtain robust data in this sense, we will test, analyze and compare the five productive options even by assuming that no financial support was given to the farmers.

This second outlook will allow identifying the real solidity of these projects in a real business investment scenario where the farmer will have to organize capital cost and cash flow in order to obtain a feasible Investment Return Rate.

For all the calculations U.S. dollar is the considered currency however, inflation rate is not considered.

Step Three – Comparison of the results

Findings for this study will be compared in order to define the best productive option for each of the dairy farmers and to identify improvements necessary to support the different alternatives.

Each alternative will be analyzed for each single dairy in order to offer indications on which alternative is more economical in relation with the number of animals, power installed, and location.

Analysis and Assumptions

Five Cases

The authors of this report decided to study five of the ten dairy farms at the object of "Dairy Methane Digester System Program Evaluation Report". In particular the candidates elected are:

- Hilarides Dairy; Lindsay, Tulare County, CA
- Castelanelli Bros. Dairy; Lodi, San Joaquin County, CA
- Koetsier Dairy; Visalia, Tulare County, CA

- Inland Empire Utilities Agency (IEUA); Chino, San Bernardino County, CA
- Eden-Vale Dairy; Lemoorre, Kings County, CA

In the Chapter six one can find all the productive data and dairy information for each of the five farms obtained from the Western United Resource Development Inc. study.

Due to time and resource constraints a standardized excel spreadsheet has been utilized to analyze the financial and productive performance of all five dairy farms.

Electricity Production Model: Inputs and Assumptions.

The *Chapter six* will list for all the five farms the inputs to the power project investment model including plant capital costs, sources of incentives, running costs and performance data. Cost and performance assumptions are listed over about four pages for each dairy. Data is grouped as:

- Capital Costs, showing all components of fully loaded cost;
- Sources of Funds, showing grants and buy-down incentives for the base scenario and all equity for the no subsidy power case (max biogas yield and no flaring options);
- Performance and Annual Operating Expenses, power installed (kW), capacity factor, actual power produced and power used on-site for dairy operations
- Payback periods

Dairy Pipeline Quality Gas: inputs and assumptions.

Chapter six will list for the five farms:

- Data inputs for pipeline-quality gas
- Upgrading system cost and requirements
- Transmissions and monitoring system costs and requirements
- Payback periods

Chapter One: California and Green House Gas Emissions

1.1 California GHG Emissions

Several Studies have been carried out in order to precisely calculate and clearly identify California sources of GHG emissions. Data available from EIA and from the California Energy Commissions offer an accurate inventory of the state anthropogenic emissions, singularly identifying values for carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and various high global warming potential (GWP) gases [1].

The purpose of this introduction chapter is to clarify California's role in the U.S.'s total emissions and the magnitude of its contribution in the warming of the earth's atmosphere and oceans. [1] In addition, an overview on California GHG emission trends for the last fifteen years compared with GDP growth rate will be offered in order to clarify to the reader the baseline scenario and to express the benefits of using bioenergy in this state. [2]

In 2004 California accounted for a gross greenhouse gas emissions (i.e., emissions from all sources, irrespective of sinks) of 492 mil metric tons of CO_2 Eq, including the emissions associated to out of state electricity production that utilized in California. [2 page 5]

CO_2 represented by far the largest pollutant emitted by California with a 83.9 percent in 2004 mainly as a consequence of fossil fuel combustion with the remaining part released by mineral production, waste combustion, land use and forestry changes. [3]

Methane, a particularly relevant emission in relation to our study, accounted for 5.7 percent of total CO_2 Eq. emissions (methane Global Warming Potential is 21 times higher than CO_2) mostly due to agriculture and landfill activities. [3 page 6]

Animal/agriculture activities, landfill disposal and mobile sources of fuel combustion resulted in the emission of N_2O, another GHG highly effective pollutant that provoked 6.8 percent GHG emissions in 2004. The remaining 2.9 percent of GHG emissions are the consequence of diverse typologies of gasses commonly associated with industrial processes and highly responsible for Ozone depletion. [2 page 6]

In 1999 state transportation emissions of CO_2 were 210 MMT and represented the 51 percent of total emissions [4 page 4]. Electricity generation is the second source followed by industrial sector while agriculture, commercial and residential activities accounted for the remaining balance.

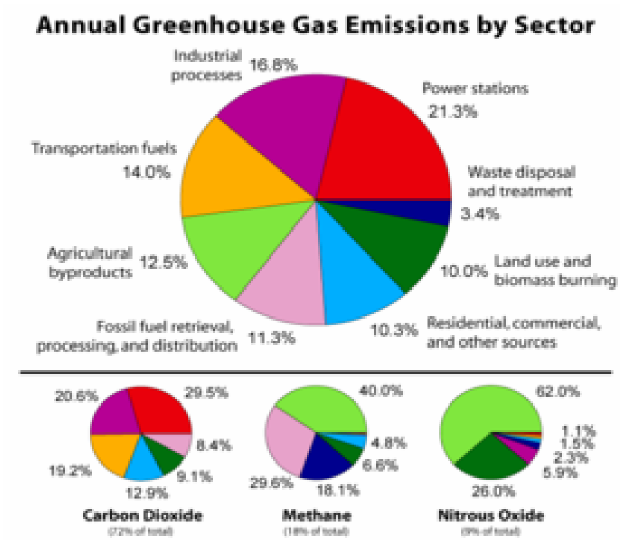


Figure 1.1 "Trends in California GHG Emissions from EPA 2005"

Our study is particularly focused on power generation technologies specifically on electricity production, trying to offer a renewable substitute to natural gas applications. For this reason we wanted to describe more closely this sector.

California electricity generation is mainly fueled by natural gas and this sector is consequently one of the major emitters of GHG in the state. California obtains only 10.9 percent of its power from eligible renewable sources while the 57.2 percent comes from highly CO_2 emitting resources (mostly natural gas and coal). Fossil fuels become a particularly important issue when California energy status is analyzed in respect to electricity production. [7]

The estimation offered by the California Energy Commission regarding the grid power mix indicates:

Fuel Type in California for Electricity Production [5 page 4]

Coal 15.7 percent

Large Hydroelectric 19 percent

Natural Gas 41.5 percent

Nuclear 11.9 percent

Eligible Renewable 10.9 percent *

*Eligible renewable consists in energy produced by at least 25 percent CO_2 free.

California produces approximately 78 percent of its electricity in-state and relying for the rest on out of state coal plants (Southwest). Even on the natural gas side only 13.5 percent is obtained from California reservoirs, while the supplies from Canada, the Southwest and the Rockies [6] help to meet the remaining 86.5 percent of the state demand. Within all the suppliers, Southwest Energy transports electricity to California with particularly high emissions per kWh. Indeed despite the relatively small amount of energy produced (15% of electricity) Southwest Energy is responsible for 60 percent of electricity associated with GHG emissions (640 metric tons of CO_2 per GWh produced against 235 metric tons per GWh of in-state).

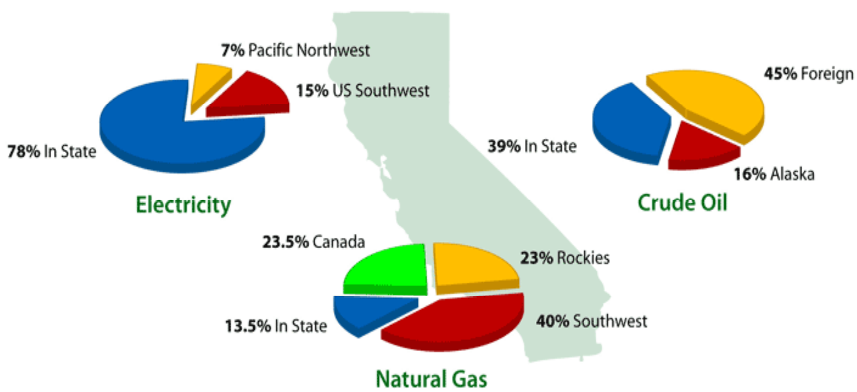


Figure 1.1.2 "California sources of Electricity, Natural Gas and Crude Oil"

The dependence on out-state highly polluting energy sources seems to be a very controversial choice especially considering the unused biomass resources available within California.

The gross potential of this resource approaches 86 mil dry tons from different sources like California dairy farms, forests and landfills.

IPCC [7] affirms, in regards to this issue, that "*Not all of the resource can, should, or will be used for power, and the technical potential is estimated to be substantially less at close to 4,700 MWe, sufficient to generate 35,000 GWh of electrical energy or roughly 12% of the current statewide demand of 283,000 GWh*".

Current California debt, which is estimated at over $20 billion, is a direct consequence of the choice made by the previous administration (Gov. Davis in office 1999 – 2003) to rely on out-of-states natural gas instead of acknowledging the value of in-state renewable resources. During the 2001 energy crisis Davis bought power at highly unfavorable terms on the open market from out-state energy companies, since the California power companies were technically bankrupt and had no buying power. California agreed to pay $43 billion for power over the next 20 years, to a price a third higher the current market price [47].
Despite the hard lesson of the 2001 energy crisis and an increasing demand, California's has not enlarged in-state production sufficiently, passing only from 200,000 GWh in 1990, to 287,00 GWh in 2005, with an overall increase of 18 percent [8].
In these terms even biomass can represent an important element not only in GHG reduction but in establishing a stronger energy base in California. [7]
In particular, the production of biogas from dairy farms manure will allow two different typology of CO_2 free energy production:

- Electricity generation through the use of a generator
- Biomethane upgrading and consequent injection in the natural gas pipeline for residential, commercial and industrial purposes. [9 page 4]

In 2005 the California Energy Commission emphasized in its Integrated Energy Policy Report the strategic value of employing California's urban, forestry and agriculture waste residues as a source of biofuels, biogas, and biopower. [10]
Biomass is a resource particularly adapt to reduce state oil consumption, achieving at the same time renewable energy, waste disposal and climate protection goals. Capturing methane from landfills and converting manure from dairy farms has a net climate change benefit, while agricultural and forest biomass can be a source of transportation fuel or combined heat.

Agriculture and Forestry. The emissions coming from this sector are mostly of nitrous oxide, a consequence of unsustainable soil management and the release of methane from enteric fermentation. These emissions increased 24 percent in the last fifteen years. [11 page 1063]

As a consequence of the agreements stipulated with the Montreal protocol, [12] California promoted a series of activities aimed to change land-use and reorient forestry. The action taken did not result sufficiently, considering the decrease in carbon sequestration recorded for the year 2006 (25 Mil Metric Tons of CO_2 emitted) compared with the result for 1999 (19 Mil Metric Tons of CO_2 emitted). The negative performance resulted in a 2 percent increase of the net emissions in the same period. [3]

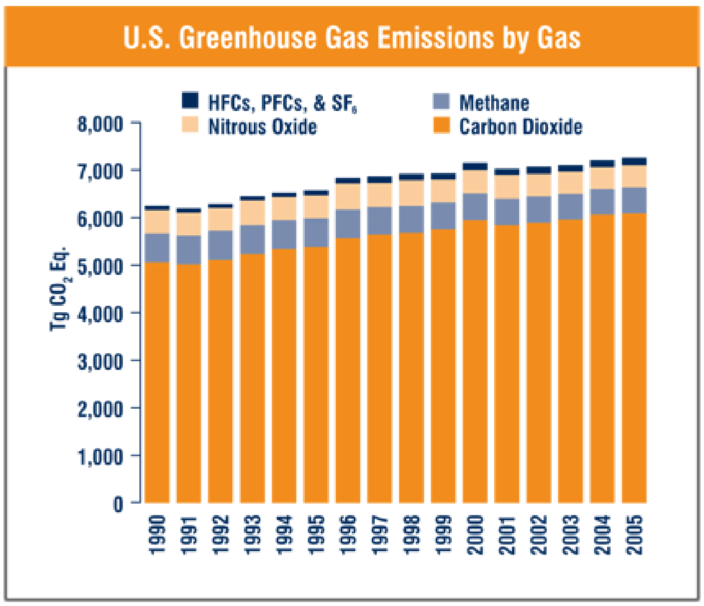


Figure 1.1.3 U.S. GHG Emissions by Gas from [13]

These values, although analyzed in the context of the U.S.'s CO_2 emission trend that consisted of a national average of 16 percent net emissions increase in the same period, represents a depreciable result. Sadly the issue here is not to produce good relative results, but to decrease the absolute emissions.

Diverse primary factors are responsible for this trend of reduction, even though they are all directly connected to energy efficiency policies and incentives to switch energy dependence from fossil fuels.

The major source of environmental degradation from animal agriculture is represented by waste products like manure, urine and bedding materials. Pollution connected with these sources is provoked by runoff from nutrients, organic matter and pathogen injections into surface water, leaching of nitrogen to ground water and the volatilization of gases [13 page 21]. Environmental impacts can occur in different locations related to the production, including:

- Houses where animals are confined
- Land where manure is applied
- Manure storage areas

1.2 California CO2 Reduction Goal

California has actively started a CO_2 reduction campaign aimed to largely decrease the amount of carbon dioxide emitted in the atmosphere. Biomass can play a primary role in the achievement of this goal.

California's current Governor, in fact acknowledging the positive outcome obtainable from these procedures, signed in April 2005 the Executive Order S-06-06 recommending an increase of bioenergy use to address multiple state policy environmental objectives. [15]

Executive Order S-06-06 points out precise targets of increase for biomass based energy production and for California air pollution legislation:

- A minimum production of 20 percent of its biofuels within 2010 and to increase this percent age to 40 percent by 2020, to then reach a 75 percent by 2050.
- Largely boost the amount of electric power obtained from biomass, imposing to meet a 20 percent target by 2010 and double it in 2020. Biomass power facilities are producing 1000 MW of electric power in 2007 but in order to meet the 2010 and 2020 targets an additional 575 MW and 1,975 MW respectively will have to be installed

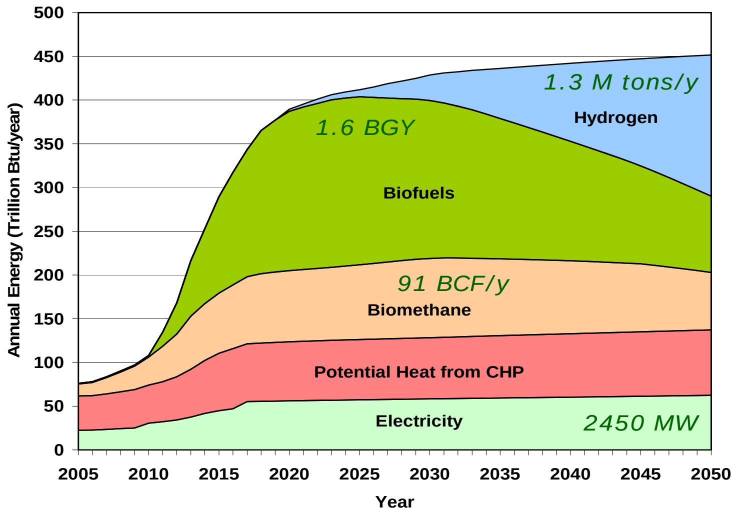


Figure 1.2 "Potential Biomass Energy in California" from [18 page i]

This second goal can be accomplished with a mutual accord with California's three main state investor owned utilities. PG&E, Southern California Edison and San Diego Gas & Electric have signed in 2007 a contract agreeing to provide 19 percent of California's Renewable Portfolio Standard (RPS) eligible energy. [16]

The Governor further promoted Bioenergy applications releasing in July 2006 the State of California's Bioenergy Action Plan [17 page 2-8] to:

- Encourage market access for new bioenergy technologies on electricity, biofuels and biogas applications.
- Align and improve California regulatory requirements to push the use of biomass for energy production.
- Maximize the contribution of biomass to accomplish California climate change, renewable energy and environmental protection policy goals.
- Coordinate the efforts on the subject of diverse federal, state and private research centers.

A specific board was created to develop a legislative campaign of support for bioenergy applications in California. The Bioenergy Interagency Working Group, which was created to address this issue, consists of nine different state agencies working more or less together to achieve the state's bioenergy objectives. [17 page 1-7]

Below are listed the group's main achievements related to biomass, electricity and biogas.

In March 2007 as part of the Preliminary Roadmap for the Development of Biomass in California, the commission enlarged the share of the state's electricity produced from renewable, establishing power purchase contracts for 391 MW and certifying 96 new biogas facilities as eligible Renewable Portfolio Standard grants. [18] In addition, the commission adjusted the procedures of the Renewable Energy Program in order to include biogas as suitable for electricity production. This particular action opened the way to new applications for biogas producers, and gave the idea to realization of this study. [18]

The commission indeed addressed $150 million in production incentives to 33 biomass power facilities that all together allowed the generation of 650 MW of renewable energy capacity.

The efforts of the state of California to value biomass-based power, resulted in additional incentives for CO_2 free power installations and in more regulatory amendments for local publicly owned electric utilities. The Senate Bill 1368 (Chapter 598, Statutes of 2006) set a more stringent standard for base-load electric generation, defining that the maximum emission rate acceptable should not be higher than the rate of emissions of GHG from a combined cycle natural gas generation, pronouncing a preference for low carbon solution such as biomass.

The Public Interest Energy Research fund (PIER) reaffirmed the interest on biomass technologies granting an additional $3 million projects for advanced energy conversion using biomass.

In this picture the diary farm industry with 1.7 million cows and with a considerable quantity of manure produced, represents a chance that cannot be missed to increase efficiency and revenues of the sector while producing $_{CO2}$ free energy. Today in California there are twenty-two dairy digesters producing biogas and converting it into electricity [19 slide 8].

In order to increase biogas production practice and methane emissions control, California State stipulated a cooperation project with the government of Sweden, where these technologies are diffused, to realize specific techniques and policy instruments [20].

California Public Utilities Commission (CPUC) in consideration of the unique benefits obtainable from biopower decided to create a special channel of grants addressed to biomass based projects supporting the installation 300 MW since 2007.

1.3 Dairy Farm Status in California

The California dairy sector is the largest in the U.S., both for the number of farms (almost 2,100 registered this year) and for the number of animals approximately 1.73 million with an impressive average size of 800 cows. [65 page 61]

The great concurrency through the US in the last fifty years in the dairy product market has pushed most of these family run businesses to associate and conglomerate.

Indeed while California dairy production has increased during this period, passing from 4.5 mil tons of milk produced in 1960 to 15 million in 2006, the number of registered farms has dramatically decreased 78 percent. [24]

In order to sustain a market that was becoming always more global and more competitive, many of these farmhouses have joined together. This brought to a smaller number of activities, but an increase in their ability to invest in technologies to increase productivities, diversification and efficiency. Through the years, Californian farm owners have demonstrated a great ability to actively develop innovation and large-scale production without losing the focus on the quality of the product or on the family spirit of how to run their business. [18 page 8] This shift towards larger facilities, however, had consistent consequences on the environmental impact caused by the sector, not only in California, but on the whole national segment. Bigger size facilities in fact often use liquid manure management systems that release higher CH_4 emission. Between 2004 and 2005 in fact a 4 percent emissions increase has been registered from this sector, which confirms the trend of 0.06 million Metric Ton of CO_2 Eq. increase yearly [25]. Previous studies have already shown how cattle can produce relevant GHG emissions during the productive cycle and how cow livestock in particular appears to be particularly impacting when all the energy inputs are accounted. [26]

The management of livestock manure can produce, in addition to the emissions of CH_4, even the release of N_2O created by the natural cycle of nitrogen through denitrification and nitrification of organic N in urine and manure. [63 page 9] Methane production is particularly interesting not only in terms of emissions produced, but also as “raw material” for energy production.

Anaerobic technologies as lagoons, liquid slurries, tanks or pits make possible the manure to decompose and create the conditions for CH_4 to flourish. Ambient temperature, residency time, moisture can influence the CH_4 productivity rate as a consequence of the impact that these variables have on bacteria responsible for CH_4 creation. [65]

Different kinds of manure, dependent on animal diet, age, species particularities and specific animals’ digestive system can also largely induce different CH_4 production results, even though the highest energy content of feed, usually the more CH_4 is produced. On the other side, N_2O creation is affected strongly by the composition of manure, the oxygen and liquid present in the substance and the typology of bacteria acting.

The ammonia is first aerobically converted in nitrates and nitrites and then through a further anaerobic reaction in nitrogen gas, while N_2O and NO result in the middle stage of this passage. [26]

1.4 Biogas involvement in California Carbon Dioxide reduction strategy

For all the facts stated above, dairy farms manure utilization for biogas production can signify a great chance to reduce CH_4 and N_2O emissions coming from this sector and at the same time produce a CO_2 free source of energy, which would indirectly reduce atmospheric pollutants coming from other industrial or commercial segments (i.e. power generation).

In California biogas is mainly produced from landfills and wastewater treatment plans, even though a large technical and economical potential still remains unused. While these two primary sources deliver respectively 8 and 11 BCF/year [18], Biogas from manure could represent a fundamental additional supply. With 1.7 million cows, California in fact could increase this amount of 40 million cubic feet per day (ft3/d) or 14.6 BCF/year [13] even though this amount is strictly dependent by the manure management system adopted. Freshness and concentration of the raw material in fact can differently affect the efficiency of this process. This technical amount could theoretically equal in electric terms 1.2 million megawatt-hours (MWh) of energy or about 140 MW of electricity (MWe) [13]. In addition, according to CARB, producing biogas via digesters could eliminate approximately 1 million tons of CO_2 equivalent (MMT CO_2E) emissions annually.

This quantity though can be largely reduced by fluid manure collection systems or by infrequent manure collection activities that provoke material decomposition. In fact, if manure is collected infrequently, different external sources of dirt can be added to the material that may provoke damages to the digester. In addition, anaerobic digesters perform best when the material has a solid content between 1 percent and 13 percent, and dairy manure with 15 percent solids mostly volatile. [63 page 10]

In California's scenario manure is commonly gathered semisolid utilizing one of these four main management systems depending from the location or the specific county legislation.

- Flushed free stall
- Scraped free stall
- Drylot with flushed feed lanes
- Scraped drylot

An estimation produced by UC Berkeley RCM offered a raw division between the different manure management systems, attributing 35 percent of the dairy farms to flushed freestall dairies, 30 percent to feed lane drylot dairies, 25 percent to drylot and 10 percent to scrape dairies. In some counties, the law requires the removal of manure if the farm does not have an appropriately large area to spread it. The installation of an anaerobic digester then can not only help to fulfill these requirements, but even guarantee economic revenue [27]

Total California potential divided for manure management systems

Flushed freestall and Scraped freestall systems usually allows the collection of 32.3 (ft3/d) of methane per cow totalizing approximately 19 million and 5.5 cubic feet of biogas a day.

Flushed drylot and Scraped drylot with a lower gross value (23.8 ft3/d and 5.6 ft3/d) could potentially produce 12.1 million and 2.3 cubic feet of biogas a day totalizing 39.2 million cubic feet of methane daily [13 page 23]. These values, however, can be largely increased once a full equipment system is dedicated to yield and process biogas.

Storage techniques can have their effect on biogas production as well. Drylot storage often inhibit the methanogenic bacteria development, which is mainly responsible for igniting the biogas cycle.

Lagoons instead, often chosen for the more practical maintenance, are strongly affected by the liquid content of the manure and have to be securely covered to avoid gas release. Furthermore, if the solid part is diluted it may sink to the bottom of the structure creating crusts [63 page 13]. This inconvenience can be avoided by the use of specific separators that can reduce the sediments at the bottom of the lagoon but at the same time reduce 25 percent of biogas yield.

Most of California dairy farms carry out additional productions in their daily business operations that involve the production of different kinds of waste materials. Food-processing waste or other sort of agricultural residues can be an interesting supplementary digestion material for biogas production that can improve the efficiency of the system offering great benefit both technically and economically. [19]

A recent study carried out by the California Energy Commission reported a gross waste potential from vegetable production of about 1.3 million BDT/year. This amount has to be reduced, because of technically and economically limitation, to only 10 percent use for methane production. This amount added to other different sources indicated by Buswell and Hatfield [28] as rice production waste, corn and cotton residue could offer an extra biogas potential of 6 billion ft^3 of methane/year. In conclusion California co-digestion activities could assure an overall technical potential of 23 billion ft^3 of CH_4/year that equal to a power installed of 220 MWe. Dairy manure management and utilization, accounts for approximately 65 percent of this total. This total analyzed on a California demand (5.7 billion ft^3/day) and supply prospective demonstrates the relevancy of this sector [13 page 27].

The aim of this study is to confront different uses of biogas, on one side electricity production and on the other biomethane upgrading. In this picture it is interesting to see that California requires 2,4 billion ft^3/day of natural gas for electricity generation and that this sector could even in a small percent contribute to this share.

Season availability and other sorts of technical constraints reduce, however, the actual amount of biogas producible from biomass and manure sources. Biogas production from manure in fact has an importance on a site-specific basis where it can play a primary role in self-efficient energy production, which is at the center of this analysis.

Chapter two: Overview on Anaerobic Digestion Technology

2.1 Types of Anaerobic Digestion

Anaerobic digestion is a natural process that converts organic materials into gas. The biological process occurs in marshes and wetlands, and in the digestive tract of ruminants. Ruminants have a unique productive cycle especially since the manure waste they produce has high moisture content. Most of dairies store their manure in ponds where the material is exposed to the atmosphere and dissolves the oxygen it contains provoking side effects like odor production. This manure though is a suitable input material for producing biogas utilizing an anaerobic digester, and with this technology even effectively reduce environmental impact as odor or waste disposal [65 page 6]. These two issues have become particularly sensitive since the California Food and Agriculture department has defined air quality standards for dairy farms [17], representing an additional incentive for the installation of this technology.

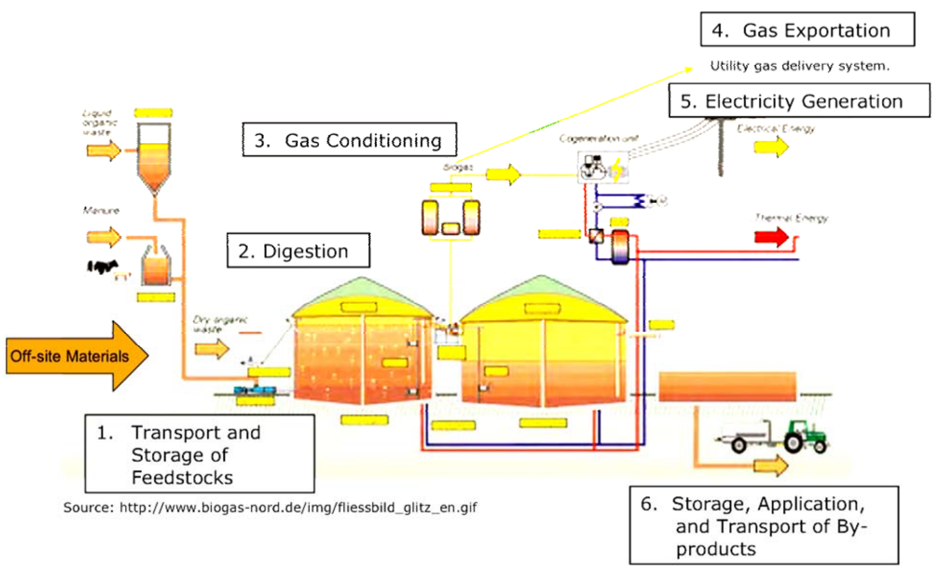


Figure 2.1.1 Manure to Biogas Cycle, from [20]

In this biochemical process biomass is digested in oxygen-free conditions where particular kinds of bacteria are responsible for methane generation. This reaction is formed by different stages where four basic typologies of microorganisms are involved. Hydrolytic bacteria serve to break the complex organic wastes into amino acid and sugars [35]. Fermentative bacteria successively reduce them in organic acids while acidogenic microorganisms transform them in hydrogen, carbon dioxide and acetate. During the last stage then methanogenic bacteria produces biogas from acetic acid, hydrogen and carbon dioxide [32 page 2].

A digester functions as an airtight chamber where bacteria can maximize the efficiency of their reaction because of the controlled temperature (68 F) [64]. Digesters with higher temperature up to 150F can shorten the process time and can minimize the volume required for the container to 40 percent. An increase in operational temperature has the drawback to require a more constant monitoring and maintenance activity.

The result of this process is a mixture of methane and carbon dioxide accounting for 90 percent and the remaining percentage represented by hydrogen sulphide, nitrogen, hydrogen, methylmercaptans and oxygen [32].

There are three basic digester designs and they all produce methane reducing fecal coliform bacteria, but they differ in climate sustainability, concentration of solids they can handle and last but not least for cost. Some of them have technology more recently developed while others have been used for many decades in municipal wastewater facilities and then converted to industrial and agricultural proposes [34].

Regardless the specific technology a dairy farm may decide to apply the following stages will be required and consist in the fundamental steps for the preparation of the manure material.

- Manure collection and handling system, which can vary in relation to the quantities of water and inorganic solids that are mixed with the manure in this early stage.
- Pretreatment cycle where the manure is checked, cleaned from grit, mixed and equalized. Most commonly a metal tank is used for this activity being especially important to block the entrance of rocks and sand that may ruin digester. In this stage it is possible to select eventual adjunctions of dry or dilute manure or mix process water. Best practice suggests installing a solid separator at the end of this stage that can be static or shaking screens typology.
- Anaerobic digester that is designed to allow methane bacteria development in an oxygen-free atmosphere can be a covered lagoon, a tank or a more engineered design

with internal baffles with a horizontal surface. Different kinds of manure will require additional technology as a heating system or a hydrogen sulphide removal.

- The digested fiber produced can be collected and stored in a side system of the digester. Frequently this stage permits to obtain material addressed to cattle bedding, even though not all manure types give usable side materials.
- The gas obtained from the previous growth stage in then accumulated beneath a rigid top or a flexible one depending on the adopt technology. The gas is then directed with a system of plastic piping to a handling area [34].
- The handling system pump or compress to the operating pressure the gas and then meter it to the gas use equipment. A clean stage often precedes this operation removing moisture and other contaminants obtaining some sort of partially upgrade biogas. The final uses of the biogas then vary the following stages.
- Inside the digester take place a decomposition process performed by fast growing and acid forming bacteria that transform protein, cellulose and carbohydrates into short-chain fatty acids mixed with oxygen and CO_2. Side effect of this stage is intense odors and side products [63 page 28]
- These organic acids are then metabolized in approx. 60% CH_4 and 40 % CO_2 by methanogenic bacteria. These agents have specific requirements to produce this reaction like a neutral pH, a two weeks hydraulic retention time to operate, and a temperature of at least 70 F [35].

The three most developed anaerobic technologies used by Californian dairy farms are [65 page 31-32-33]:

1. Plug Flow Digester

   Manure with a higher content of solids (average 10%-14%) is suitable to be processed in this kind of digester even though in case the material is too dry and an addition of organic waste material may be necessary. This technology works without mixing the material but simply displacing the digested material with new one in a heated tank.

2. Covered Lagoon Digester Very

Low solids content manure, often daily collected, is digested with this system that does not require a heating system. There is not screening stages in this technology, so the material has to be separated from solid parts before the insertion. If this doesn't happen a crust will be formed reducing biogas production efficiency.

3. Complete Mix Digester

   Diverse manure typologies with a solid content lower than 10% are handled utilizing a heating system a circular tank and a gas or liquid recirculation system.

Table 2.1 Typology of Digesters, from [13] page 32

Typology	Technology Level	Solids Concentration	Maximum concentration of solids	Additional heat necessary	Hydraulic Retention Time
Covered Lagoon	Low	0.1-2	Fine	no	At least 40 days
Complete Mix	Medium	2-10	Coarse	Yes	At least 15 days
Plug Flow	Low	11-13	Coarse	Yes	At least 15 days

Optimal temperature ranges for anaerobic digestion are thermophilic (125F to 135F) where the biogas is produced in a shorter time or mesophilic (95F-105F) that requires less energy to be implemented and so can maximize the amount of waste heat recollected.

Systems without heating facilities (Lagoons) are more fluctuant in terms of efficiency because dependent from ambient temperature while plug-in-flow and mix digester can assure higher performances through a more favorable microbial activity.

The three options have been compared utilizing AgStar Farmware, software able to forecast the production rate of the different anaerobic digester kinds, once the productive data have been hypothesized [35].

For 1000-Cow Dairy in California compared on an annual basis a complete mix digester and a plug flow one would both produce 20 million ft3 of biogas against the 16 mil ft3 of the lagoon type. Once compared the efficiency, it is important to note that a complete-mix digester requires higher investment costs than a plug flow and would need a liquids tank to operate properly [35].

2.2 Benefits from Anaerobic digestion

Environmental performances of an anaerobic digester are strictly dependent manure management strategy adopted. On a normal base direct environmental benefits from biogas generation are:

Reduction of Green House Gas Emissions

Biogas production from dairy farms is able to actively participate directly and indirectly in the reduction of GHG,

First of all, ruminants release during their life cycle and daily activities high quantitative of CH_4. In addition the manure produced can represent a relevant source of CH_4 if not properly managed and treated [36]. EPA reports that in 2005 manure management released 41.3 Tg CO_2 Eq of methane, 9.5 Tg CO_2 Eq. NOx out of a total U.S. GHG emissions of 6,431 Tg CO_2 Eq that year [37].

Further on the biogas produced from manure is going to replace fossil fuels (in California mostly natural gas) used to generate electricity. This substitution allows avoiding GHG emissions that conventional power generation would have produced.

The digestion of manure permits to capture the CH_4 that can be combusted to produce energy. Since CH_4 has 21 times GWP of CO_2, a single molecule of CH_4 captured and burned produces 1 molecule of CO_2, obtaining in the end a gain of 20 molecules of CO_2 avoided [38].

A fundamental step of this analysis in terms of condition of agreement with the utilities owners will be to evaluate how the use of generated biogas can be maximized. Often indeed electric utilities purchase only an amount of power equivalent to the one consumed by the dairy farm, without compensating any extra power [19 page 22]. With these terms most of the farms prefer to size their generators in order to strictly sustain their own needs regardless of the biogas effectively produced. Consequently the efficiency of the system is greatly decreased and often the extra biogas is not processed but simply released in atmosphere, compromising the GHG benefit of the technology.

Odor Control

The fact of producing large quantities of manure as a side product creates many problem to dairy sector in terms of odor control and external impacts on neighbor communities.

Anaerobic digestion required fresh manure to be more efficient, reducing in this way the exposure of this material to open air and consequently the odors produced [39 page 1].

In addiction the more odoriferous materials are usually located in the depth of the pond, where the digestion takes place. This cycle so reduce those materials and consequently the odor produced while releasing gas odorless as carbon dioxide and methane [40 page 6].

Nutrients Emissions

A proper manure management together with a anaerobic digestion system not only can represent a source of profit but also can give to dairy farms operational advantages. The elimination of excessive phosphorous and nitrogen can provide a cost saving by avoiding unnecessary supplements without lowering milk production. In addition the probable more stringent regulations on air and land emission will require expensive cleaning technologies that could in this way be evaded [36].

Water Quality Benefits

Manure utilization is an effective tool to reduce BOD content in the wastewater coming from a dairy farm. Usually animal agriculture water has BOD content 40 times higher than domestic water with consequent impact on the land in which is discharged. The anaerobic digestion can reduce this value of 70 – 90 percent.

For what concern the nutrient content of the digested material, anaerobic digestion will not particularly affect the material but eventually retain a 30 % of P and K in the sludge [13 page 38].

VOC Emission Reduction

Volatile Organic Compounds are a major issue in California for their involvement in tropospheric ozone formation, a serious concern for the so-called SMOG creation. Special federal laws regulate the emissions of VOC from dairy farms and landfills as VOC are produced in the digestion process of cows and by anaerobic decomposition of manure. In this second process methanogenic bacteria create VOC, but the more efficient the CH4 production process is, the lower quantity of VOC is released [63 page 36].

In order to quantify the VOC emissions directly associated to dairy farms activities California Air Resource Board defined an emissions factor of 12.8 lb of VOCs per cows per year.

The San Joaquin Valley were the issue is more addressed ruled, that dairy farms with more than 2,000 cows will have mandate to install an anaerobic digester considering this the Best Available technology to fight the issue.

Dairy farms have even been recently (Senate Bill 700) included in the Clean Air Act that define stringent emission limits especially in relation to areas specific environmental impacts.

Pathogens and Weed Seeds Control

High temperature treatments are widely recognized for their effect in pathogens and weed seeds elimination. Consequently digesters operating at mesophilic and thermophilic temperature are very useful in diminish pathogen content and denaturing weed seeds in a 20 days retention time. Cover lagoon digesters operate at atmospheric temperature and this reduces the ability to be effective in pathogens reduction [13 page 37].

2.3 Potential negative effects of Anaerobic Digestion

An improper management of manure can have detrimental effects on air and water. The use of water for everyday cleaning activities concomitant with an inappropriate manure collection and storage can produce an environmental impact on water resources in terms of ammonia, different typologies of nutrients, (mostly nitrogen and phosphorous) and organic matter (especially VOC). These three classes of contaminants provoke aquatic toxicity, depletion of oxygen and algal proliferation. On average, a California Dairy Farm with 1000 cows (a average size) produces annually 3,600 tons of dry manure, including 180 tons of nitrogen and 235 tons of inorganic salts. The discharge of these substances can have a detrimental effect on surface water and groundwater independently by the fact that farm operates an anaerobic digester or not. A maximum contaminant level has been set up for nitrates considering the health concerns that this may create even in low concentrations [37].

For the manure management though, anaerobic digestion can help to reduce the quantitative of material that is spread on the cropland. Urbanization in cattle areas has reduced the number of hectares available to dispose manure, increasing in this way the quantitative for square meter and impacting on the ground quality [19].

2.4 Regulatory Agencies involved in Biogas

The production of biogas involves, as shown above, different areas of natural resources having an effect directly or indirectly on air, water, land, energy and waste.

For this reason regulations that affect biogas and biogas producers are not generated from a dedicated organism but from a diverse number of institutions [13 page 47].

The following state and federal agencies have at different levels jurisdiction on biogas cycle and the regulations they emit can facilitate or slow the development of this practice.

California Public Utilities Commission (CPUC) regulates, between the others, the operations of privately owned electric and gas companies that represent the main purchaser of biogas based power and biomethane. This organism legislates the terms of the deals between PG&E and dairy farms defining if those terms are fair and coherent with Californian regulations [42].

In February 2007 PG&E submitted to this commission a request for purchasing of biogas from a dairy farm and to inject the upgraded biomethane in California pipeline. Such a request was accepted in the May 2007 opening the way to new commercial market for biogas producers [41].

State Water Resource Control Board (SWRCB) is on charge to regulate, control and persecute all the activities that have direct or indirect effects on water quality and water environment life. Animal and agricultural activities have particular impact on the salinity of surface and underground water and this issue is of direct competence for the SWRCB. This issue became particularly significant in Central Valley area where dairy farm activities are mostly flourish and expanded. The use of other feedstock material like agricultural or food waste in the digestion could intensify the salts content and have detrimental effects on the land area on which the wastewater is discharged.

To avoid such impacts the Central Valley commission required each dairy farm to report the sources of salt in their wastes and to propone minimization action [13 page 136].

On a State basis California doesn’t have a regulation that define the salinity limits for any sort of waste and not even Central Valley commission has defined such limits but only identified the problem.

California Air Resource Board (CARB) is on charge for regulate and implement legislation oriented to diminish emissions from mobile and stationary sources. This commission is divided in thirty-five under-organs that locally define and address the issue. CARB main purpose is to reach the goal of emissions reduction as stated in the California’ Global Warming Solutions Act of 2006 and in this context to promote biogas application as a substitution of fossil fuel powered electricity [43].

Until the acceptance of the Senate Bill 700 the agricultural sector has always been somehow excluded from air pollution control or permits requirements. Since 2003 with the enactment of the Bill the situation changed and CARB starting define air quality requirements for Confined Animal Facilities.

The San Joaquin Valley has been particularly active in implementing air pollution control for dairy farms, predominantly located in this area. VOC is the main concern of the institutions of the county together with NH3 and PM [19 page 18].

As a consequence of the Bill 700, the Clean Air Act has included dairy farms in the list of the activities under control. This Act requires State and local governments to identify area where the standards are not met, and to obtain from those businesses the submission of a plan within February 2008 on how they intend to meet such standards. Animal operation will be affected by the Act, being major emitters of ammonia that is a precursor of fine particulates [13 page 36].

Assembly and Senate Bill related to biogas production

AIR QUALITY

AB 233 (Jones) Penalties for air Pollution

AB 255 (De Leon) Clean Air and Energy Independence Fund

CLEAN TECHNOLOGY

AB 1285 (Parra) Tax Incentives for Clean Technology

AB 1527 (Arambula) Cleantech Advantage Act of 2008

AB 1620 (Arambula) California Clean Technology Services Unit

CLIMATE CHANGE

AB 6 (Houston) Market-based compliance mechanism for Greenhouse gases

AB 109 (Nunez) Annual report of CA Global Warming Solutions Act of 2006

AB 114 (Blakeslee) Carbon Dioxide Containment Program

AB 657 (Jeffries) Changes to Global Warming Solutions Act of 2006

AB 1506 (Arambula) Loans/Tax Credit for Greenhouse Gas Reductions

AB 242 (Blakeslee) Greenhouse Gases Emissions Reduction

SB 247 (Ashburn) Modifications to AB 32 Provisions

DISTRIBUTED GENERATION

AB 1064 (Lieber) Self-Generation Incentive Programs

AB 1613 (Blakeslee) Waste Heat and Carbon Emissions Reduction Act

SB 463 (Negrete Mcleod) Biogas Digester Program

ELECTRICAL GENERATION

SB 871 (Kehoe) Expedited Siting of Electrical Generation

LIQUEFIED NATURAL GAS

SB 412 (Simitian) Liquefied Natural Gas Terminals

RATES AND TARIFFS

AB 1223 (Arambula) Net Energy Metering for Agricultural Customers

AB 1428 (Galgiani) Biomass Conversion Customer-Generator Program

AB 1517 (Jones) Regulation of Utility Rates

RENEWABLE ENERGY

AB 94 (Levine) Renewable Energy Portfolio Standard

AB 578 (Blakeslee) Renewable Energy Generation Study

AB 811 (Levine) Tax Credits for Eligible Renewable Energy Resources

AB 946 (Krekorian) Renewable Energy Resources

SB 410 (Simitian) Renewable Energy Resources

SB 411 (Simitian) Renewable Portfolio Standard Compliance

SB 660 (Perata) Supplemental Energy Payments for Renewable Energy

SB 1012 (Dutton) Renewable Portfolio Standard Compliance Body

SB 1036 (Perata) Renewable Energy Incentives and payments

2.5 Incentives for Biogas Producers

Due to a severe crisis in Federal founding that required each California administration department to cut 20 percent of their budget starting from 2007, incentives availability may change yearly. Many funds (below), theoretically offer sustain to farmers to develop these technologies, but strict requirements on eligibility may reduce the real availability.

a. Federal Incentives

Environmental Quality Incentives Program (EQIP)

USDA's Natural Resources Conservation Service administrates the EQIP funds promoting agricultural activities in respect of environmental quality. The incentives are distributed prioritizing areas with high environmental issues providing up to 75% of the costs of certain conservation practices with a contract length of one year after the installation of the last system up to 10 years [65 page 16].

Local Conservation agencies define which projects are eligible for the grant and choose usually the most cost effective and environmental efficient projects. The financial requirements of this project restrict the access to this fund to company that do not exceed a gross income of $2.5 million, unless the 75% of this income derives from farming, forestry and ranching [Environmentaldefence.org].

Renewable Energy Systems and Energy Efficiency Improvements Program

The Rural Business-Cooperative Service (RBS) has granted $23 million in 2003 for competitive grant funds for farmers, ranchers, and rural small businesses to develop renewable energy systems, such as anaerobic digesters. The grant money may pay up to 25 percent of the eligible project costs, such as professional service fees and equipment and installation costs. The availability of additional grants is considered annually by the agency [45 page 9].

b. California State Incentives

Dairy Power Production Program California Energy Commission (CEC) initiated this program to sustain distributed power generation in dairy farms. Within the DPPP, that distributes annually approximately $10 million, are included both grants, usually covering 50 percent of capital costs, and production credits of $2,000 per installed kilowatt. The program, administered by Western United Resources Development, has financed already 10 projects [45 page 17].

Renewable Portfolio Standard Program

This program requires the investor owned utilities and public utilities to increase their purchases of electricity from eligible renewable energy technologies (including biomass, digester gas, landfill gas and municipal solid waste conversion) by at least one-percent a year to reach 20% of their retail sales within 2017 [69].

Renewable Energy Program (Electricity Generation)

This program of incentives provides additional energy payments to encourage development of existing, new, and emerging renewable based generation technologies[70].

- Existing Facilities

  This section of incentives directed to energy generation from renewable is specifically addressed to existing generators and has been supporting more than a hundred facilities with almost $200 million predominately biomass combustion and solar thermal.

- New Installation (Electricity)

  The aim of this part of the incentives is to encourage new electricity generation. The projects coming on-line are eligible for supplemental energy payments (SEP) for the first five years of generation or for ten years to meet above-market costs of RPS requirements.

  The incentives payment is corresponded for kWh produced with a value that ranges from 0.0068 to 0.0148 cents/kWh.

- Emerging Installation (Electricity)

The rebates provided with this fund are directed to all the grid-connected utility customers for the purchase of renewable energy generating systems less than 30 KW with digester gas listed as one of the eligible technologies.

For the year 2006 $70 million were available for this purpose with rebates that vary for size and technology from $0.70 to $3.20 per watt.

Dairy Power Production Program (Electricity)

The fund is intended for promote anaerobic digester installation or gasification projects generating electricity on dairies both for plug-in-flow or lagoon technologies.

The rebate was offered in two ways covering up to 50% of the capital costs of the biogas system or as an electricity generation incentive payments of 5.7 cents per kWh. Fourteen projects for a total 3.5 MW of power installed have been granted as of May 2004.

California Pollution Control Financing

This program named Small Business Pollution Control Tax-Exempt Bond Financing Program finances with low-interest rate loans, small business to install pollution control technologies. Eligible projects include waste-to-energy, resource recovery, landfill gas and dairy manure projects.

Self-Generation Program (Electricity)

Since the Assembly Bill 970 has been approved in 2001, the California Public Utilities Commission obliges utilities to provide financial incentives to customers who install distributed generation under the Self-Generation Incentive Program (SGIP). The funding is capped at 50 percent of the total project cost while projects using digester gas can qualify for Level 3-R with an incentive at the lower of $1,500 per kW or 40 percent of the eligible project costs. Only projects with a maximum system size of 1.5 MW are qualified for incentives, although incentive payments are limited to 1 MW of generation. The site must be connected to the electricity grid and offset a portion of its electricity consumption. Self-generation equipment must be new and permanent (i.e., demonstration units are not eligible) [45 page 19].

Chapter three: Biomethane Upgrading Technology

3.1 System Required

Biogas produced from dairy farms through anaerobic digestion can be utilized to generate electricity and heat or can be upgraded to biomethane and used as a substitute of natural gas. Today there are worldwide a very limited number of gasification systems that deliver biomethane to the grid as a consequence of the often not competitive price compared to natural gas [53 page 1].

A way to improve the economic efficiency of biogas is to deliver it through the grid together with natural gas to locations where all the gas can be used. One of the aims of this project is to evaluate the economic and technical feasibility of this option and compare it with electricity generation on-site.

Pacific Gas and Electric (PG&E), one of the main utilities operating in California, owns great part of the natural gas distribution line present in the state. PG&E has recently decided to approve purchasing contract of biomethane produced from manure and allow the injection in the natural gas pipeline, once all the quality requirements are met [53 page 9]. These standards mainly require H_2S, moisture and CO_2 to be removed because the presence of these compounds in the gas can have high-risk impacts on the reliability of the injection system and the corrosion of the parts [13 page 75].

Quality gas from biomass could theoretically:

- Be used in highly efficient applications because once added to natural gas will power appliances already conformed with efficiency standards
- Have nearly unlimited distribution and transport facilities avoiding issues in finding a customer
- Be used in multiplex ways from heat and power, to cooling and refrigeration and transportation
- Help to peak shaving using natural gas as a reserve and so avoiding any sort of biogas flaring
- Unconditioned utilization as a transport fuel
- Unconditioned utilization in distributed power production

Despite the positive incentive demonstrated by the utility owners, previous experiences have underlined several institutional and legislative barriers to the deployment of this alternative.

Technologies for Methane content increase

The technologies that would be introduce below have been developed and utilized for several years to increase the methane yield out of biogas produced in waste water treatment plants and landfill. Further researches have demonstrated though the applicability of these practices in the manure management.

The possible techniques include:

Preheating is an effective system in slaughterhouse waste as shown by few applications in Sweden [35]

Ultrasonic devices that uses low-frequency ultrasound to induce sludge disintegration, even though this technology is not yet applied to solid manure waste with high celluloid content.

Microbials stimulating applications have demonstrated on a laboratory scale to increase gas production of 55% in cattle manure management [52]

Co-Digestion with other typology of waste for example food, animal by-products and sewage sludge can gain additional benefits though a better nutrient balance. This strategy will permit economical benefits with an increased gas production and from tipping fees.

Reading degradable substrates obtain the best yield of CH_4, even though in case of industrial and slaughterhouse waste, the amounts have to be properly balanced to avoid incurring in inhibit the anaerobic digestion process [34].

3.2 Upgrading to Biomethane

Technologies to purify from H_2S

As exposed above the corrosive nature of H_2S requires purifying the gas from this substance first, avoiding in this way even side impacts as unpleasant odor. This process named commonly sweetening allows reducing the concentration of H_2S in biogas (normally from 1,000 to 2,500 ppm) together with minor traces of mercaptans [53 page 12]. Different technologies have been applied to H_2S removal and the most developed are:

a. The injection of 2% to 7% of air or oxygen into the digester obtaining a reduction of 95% in H_2S concentration. This strategy, particularly cheap in cost and easy to implement, is commonly applied in manure management systems where a further purification is not required. A possible negative effect of this system is to allow the proliferation of explosive mixture gas when too much air is injected.

b. Iron Chloride injection permits an easy reduction of H_2S content by reacting with it and forming iron sulfide salts particles.

Iron Oxide or Hydroxide Bed react with H_2S reducing its presence in the biogas. The process that requires water and a temperature between 77F and 122 F sees the iron oxides to produce a so called “sponge effect” where H_2S can be reduce to below 1 ppm, being so suitable for any sort of application [53 page 14].

c. When the H_2S concentration is higher, activated carbon sieve appear to be the most efficient solution to decrease this concentration. In this process CO_2 and vapor are captured as well as far as the process is maintained at a temperature between 122F and 158F [53 page 42].

Other technologies are known for H2S removal but are not further analyzed because represent too expensive, not fully applicable or environmental debatable solutions.

Technologies to remove Water Vapor

Water vapor is another main reason for corrosion in pipeline and collection equipment of an anaerobic digester. For this reason a quality standard for water vapor content has been defined by PG&E in order to consider biomethane from manure treatment eligible to be injecting in the system. Vapor is usually formed above the liquid surface with a ration that depends by temperature and pressure in the tank. Particularly import is to remove vapor when H2S has not been yet removed. The two agents reacting together can result in the formation of sulfuric acid and the consequent corrosion of the system. The simplest method to eliminate water content is to use a refrigeration unit that condense water on the cooling coils and capture it in a trap. On a dairy application refrigeration units with a capacity of 0.5 to ton are commercially available and easy to use. These units have usually a low energy demand that never exceed 2% of the energy included in the gas [13 page 51].

Technologies for Carbon Dioxide removal

CO_2 removal techniques are fast developing in different field and diverse technologies are specializing always more in particular applications [58 page 3].

- Water scrubbing allows obtaining 95% reduction in CO_2 content with a high-atomized process where biogas is pressurized (150-300 psi) and then introduce in at the bottom vertical column. Water is introduced from the top and allows the biogas to pass through in bubbles while CO_2 saturated is withdrawn from the bottom. This system is the most common application to meet cheaply and easily a CO_2 reduction without any large (less than 2%) CH_4 losses. Only main con of this technology is the higher (compared to similar systems) energy requirements that can be reduced with the use of a single column [58 page 4].
- Pressure Swing Adsorption uses a system where columns filled with molecular sieve absorb both CO_2 and H_2S. The system operates with four columns that upgrade the biogas decreasing the pollutant content. The biogas is purified in a column and passed in the next where the content of CH_4 is further increased. The final result gives the cleaner biomethane obtainable from biogas requiring though sophisticated control steps.
- Amine Solvents for chemical scrubbing is particularly effective in reducing the CO_2 content in biogas, and become particularly energy efficient if waste heat recovery is available. This process though is not recommendable for small size applications like dairy farms.
- In case the end objective is to produce liquefied biomethane the Cryogenic Separation can be considered a possible solution. Liquefying CH_4, CO_2 and other contaminants the following separation become easier even though is not clear if economically feasible.
- Membrane Separation uses different stages of selective selection where CO_2 is filtrated. At a temperature of 140F and an increasing pressure this system allow a yield of 96% pure CH_4. The short lifetime of the membranes reduce the economical availability of this system. [58 page 5]

The materials used for the different adsorption technologies can usually be regenerated do not representing so an environmental concern. Liquid base absorption process can create issues related to water disposal. Chemical removal processes represent the major concern in terms of end of life products. These chemicals can be partially released during the use or be a hazardous waste for any type of scrubbing [13 page 59].

Biological gas clean-up technologies can produce the flowing out of sulfur particles but it is hard that the process could produce dangerous amount of particles.

The estimations offered above follow the indications offered by Barker (2001) where it is suggested a yield of 30 ft3 of biogas per cow per day.

Two days collecting period, an average of 1,400 lb cows and a daily production of 120 lb have been considered by the author of the estimation. In addition a loss of 25% is accounted when solids are separated and 1 lb of volatile solids from dairy cow is digested to produce 3 ft3 of methane.

For this kind of assets is preferable to install the equipment on a skid where the H_2S scrubber, iron sponge based, will have a top cover to collect spent residues and the compression units will pump the gas in the columns to separate CO_2.

Regardless of the particularity that each specific case could require a general design for an anaerobic digester system to produce biomethane, would require:

a. A system to remove H_2S (iron sponge based)

b. Compression and storage units

c. A system to remove CO_2 (most commonly a water scrubber)

d. A refrigeration system to condense vapor and remove water

e. A system to compress the gas to obtain Biomethane.

Table 3.2 Biomethane upgrading equipment necessary for dairy farm (800-1800 cows) from [13] page 61

Component	**Size/Capacity**
Iron sponge H_2S scrubber	• 75,000 ft3/day • 6 ft. dia x 8 ft. high
First-stage compressor (centrifugal Blower	• Intake capacity = 100 ft /m compression to 8 psig
Modified piston compressor	• 1st stage compression from 8 to 40 psig • 2nd stage compression from 40 to 200 psig
Pressurized storage tanks	•2 x 5,000 gal. Propane tanks
Water CO_2 scrubber	• Two 12-inch diameter x 12-ft columns with Jaeger packing • Water pump, piping, pressure valves, regulators • Operates at pressures between 200 and 300 psig
Flash tank, gas recycler, chiller to reduce moisture	Standard
High-pressure compressor	Compression from 200 to 3,000 psig (small unit)

An additional equipment of regulators and pressure valves will keep under control the skid while a flash tank; a gas recycler and a water vapor moisturizer take care of secondary phase [13 page 62].

The compression system primarily and the upgrading technologies will require a certain amount of electricity that can be produced directly on site in case the final purpose is to generate power or can be purchased by the utility contractor. In case the power is purchased the environmental impact produced by the power generating system (Coal or Natural Gas in California) will have to be considered and be subtracted from the environmental benefit produced by the system.

Compression Stage

In order to be utilized as a clean substitute of natural gas, biomethane needs to be compressed at least to 3,600 psi that guarantees 24,000 Btu/gallon content. This value is 5 to 6 times lower than the Btu content of gasoline or diesel with consequences in terms of storage and fuel efficiency [58].

Storage, Transportation and Connection to the grid

Once the biogas produced as been purified in order to meet the quality requirements defined by PG&E for been injected, it has to be stored and transferred to the end user. Storage could became necessary even in case of on-site generation considering that often the amount of biogas produced is higher than the effective power installed n the farm [19]. Low pressure storage systems permit to reduce cost of in-site storage for electricity generation purposes while the more advanced technology required to guarantee a medium or high pressure system can become affordable for mostly of the family run dairy farms only when biomethane is produced [59 slides 6-13].

Biomethane Storage

The higher value of biomethane can allow developing a more expensive system for high-pressure technology. The high-pressure system requires a more sophisticated scrubbing system to reduce the water vapor and H_2S content of the gas. A study offered by [51] offers an estimation of the cost required to high-pressure store biomethane. Considering a final compression between 2,000 and 5,000 psi, that requires 14 kWh per 1,000 ft and a quality level of 97% CH_4, the heat rate will result in 12,000 Btu/kWh equal to 17% of energy content of the gas. A low-pressure tank will be necessary as a buffer for a dairy farm (1,600 cows) that produces approximately 4,000-ft3 biomethane/day with a flow of approximately 2,500 ft3 an hour. Once the biomethane is secondarily pressurized, it is stored in smaller high-pressure tanks in parallel.

Distribution

Biogas without a secondarily purification has a low-value that cannot justify an investment to transport it. Otherwise biomethane a more precious gas can be transported with different ways in relation to the location of the diary farm and of the end user collecting structure [50].

California highly relies on Natural Gas for heating and power generation and in the last decade the pipeline network dedicated to this gas has been greatly expanded. PG&E in our specific case owns a large share of NG pipeline and has previously agreed purchasing deals with biomethane producers. These deals are currently not public which makes hard to evaluate the terms and the profitability for the farmers.

The positive side of biomethane that has met the quality standards defined by the utility owner is that can perfectly substitute natural gas in any sort of application both commercial and civil [60 slide 7].

Despite the initiation of two project oriented to produce biomethane for pipeline injection, the resistance from utility owners side seem to be quite firm toward a large-scale development of this practice. This is explained by the significant impact that an eventual low quality gas injection would cause to the network system. Severe quality requirements, defined in the next paragraph, and fail-safe disconnection system could extremely increase the investment costs.

Mixing the biomethane with natural gas will imply to define the price equal to natural gas, even though additional revenues could be obtained from green certificate incentives.

In case the production point is close to PG&E collection area, the option of a dedicated biogas pipeline can be taken in consideration even though only with great scale production since the cost for laying such infrastructure may be over $250,000 per mile. This high investment costs will have to be written off with the revenue of biomethane selling, which has to compete at the same price of natural gas [13 page 72].

3.3 Biomethane Quality Standards: PG&E's regulation

PG&E has defined the minimum quality requirements that have to be met by biomethane to be injected in the pipeline in the Rule 21.

Section C of the document provides clear indications for the biomethane producers in order to deliver gas in the PG&E pipeline system, even though the personal nature of the deal between PG&E and the producer may supersede these rules [54].

" Carbon dioxide: The gas shall contain no more than one percent by volume of carbon dioxide.*

** Oxygen: The gas shall contain no more than 0.1 percent by volume of oxygen.*

** Total Sulfur: The gas shall contain no more than one grain (17 ppm) of total sulfur per one hundred standard cubic feet."*

** Mercaptan Sulfur: The gas shall contain no more than 0.5 grain (8 ppm) of mercaptan sulfur per one hundred standard cubic feet.*

** Hydrogen sulfide: The gas shall contain no more than 0.25 grain (4 ppm) of hydrogen sulfide per one hundred standard cubic feet.*

** Water vapor: The gas shall contain no more than seven pounds of water vapor per million standard cubic feet at 800 pounds per square inch gauge (psig) or less; dew point of 20° Fahrenheit (F) if gas is supplied at over 800 psig.*

** Hydrocarbon dew point: The gas shall have a hydrocarbon dew point of 45°F or less for gas delivered at 800 psig or below, but measured at 400 psig; or 20°F for gas delivered at above 800 psig, also measured at 400 psig.*

** Liquids: The gas shall contain no liquids at, or immediately downstream of, the Receipt Point(s).*

** Merchantability: The gas shall not contain dust, sand, dirt, gums, oils, or other substances in an amount sufficient to be injurious to PG&E facilities or which shall cause the gas to be unmarketable.*

** Temperature: The gas shall not be delivered at less than 60 degrees Fahrenheit or more than 100 degrees Fahrenheit.*

** Gas interchangeability: The gas shall be interchangeable with the gas in the receiving pipeline. Interchangeability shall be determined in accordance with the methods and limits presented in Bulletin 36 of the American Gas Association.*

** Heating value: The gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point.*

** Biogas: Biogas refers to a gas made from anaerobic digestion of agricultural and/or animal waste. The gas is primarily a mixture of methane and carbon dioxide. Biogas must be free from bacteria, pathogens and any other substances injurious to utility facilities or that would cause the gas to be unmarketable and it shall conform to all gas quality specifications identified in this Rule. " end quote from PG&E Rule 21 Sec. C [71]*

In addition EPA has defined air quality standards for pipeline gas as follows:

"Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot."

One way to meet these criteria is making sure that the total sulfur content will not exceed 0.5 gr/100 scf, which will be regularly controllers by PG&E analysts.

PG&E tests for sulfur using ASTM D 5504 "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence." The detection limit is approximately 10 PPBv for each compound. PG&E odorizes gas with a 50/50 blend of Tetrahydothiophene (THT) and Tertiary Butyl Mercaptan (TBM) and they are typically present at approximately 1 PPMv each in the natural gas on our system." From EPA [40CFR72.2]

3.4 Assumed Deal with the utilities

A value of $6/ MM Btu have estimated in this report for biomethane produced from manure, after discussing the issue with sector experts. Currently market price for Natural Gas is indicated by the California Energy Department $7.21 per MM Btu to residential customer. At this value we subtracted PG&E margin (0.65 $/MM Btu), obtain a price paid by the utility to a usual natural gas producer of $6.56/MM Btu [72].

Different sources of the RAEL Lab confirmed us an additional environmental premium ($20/MWh) that PG&E could correspond to biomethane producers as compensation for the Renewable Energy Credits generated, very precious to the utility in order to reach a 20 percent renewable energy share within 2010.

This extra value has not yet been confirmed by IOUs and so it will not considered in the accounting, totalizing an estimated value of $7/MM Btu that has been considered for the scenario 6.

Fluctuation of Natural Gas price would heavily influence the price corresponded to dairy farmer for biomethane, even though in most of the cases, like happened for the Vintage Farm, a fixed price will be agreed for the all purchasing period (usually ten years). The increase in natural gas price and its availability though could result in a key element in the development of this practice.

California demand of natural gas has grown steady in the last decade passing from 5343 mmcf per day in 1996 to 6589 mmcf in 2006 [47]. This growth is expected to maintain the same path with small fluctuations, both in the short and long run, indeed [47] forecasts a NG demand in 2016 of 7058 mmcf per day.

Producing biomethane farmers can:

a. Maximize the production and avoid any no biogas to be flattered

b. Sell biomethane with a price calculated on NG price, which is increasing constantly. More probable farmers will sign 10 years contracts with fixed terms but this price will consider the price trends and will be re-discussed at the end of the period.

c. The plan to upgrade the natural gas network may allow a reduction in connection and injection costs for farmers.

d. The high dependency from out-state sources is putting California is a very passive situation toward price control. In this scenario is not wrong to expect that in-state production will be supported in the long term by California Energy Commission.

Chapter Four: Electricity Generation Technology

4.1 Electricity Production

Electric generation is today the technical option chosen by the majority of the dairy farmers that produce biogas from cattle manure with an anaerobic digester [59].

It is important to precise though that only recently, June 2007, PG&E has accepted to purchase directly biomethane produced in farms and inject it in the network, and so it will be interesting to see how this second option would change this distribution.

In order to produce electricity from the biogas obtained from digested manure a dairy farm will need to install a generation system that simply with use the biogas has combustion fuel.

An internal combustion (IC) engine or gas turbine driven generator to produce electricity are the most common technical system utilized to meet this objective, because they guarantee a good energy efficiency while are a diffuse and well-known technology.

The use of an internal combustion engines will allow the farmer to produce energy that offset the energy demand of the farm daily activities. In addition this cycle permits recovering waste heat and hot water that can be used for manure pre-heating or for other activities in the farm [61].

Electricity Generation System Components

Typical electricity generation systems consist of:

- IC engine or a gas turbine. Most natural gas or propane engines are easily converted to burn biogas with small changes in the carburetion and in the ignition system. Normally, a good quality engine will allow converting 19 - 25 percent of biogas Btu in electricity depending on the load factor. Usually 150 KW engines are designed to comply with California air pollution regulation. In case the county where the farm is located require particular stringent levels of NOx emissions, then a gas turbine would probably result the best option to consider.
- Generator. There are two typologies able to function in this system: an induction and a synchronous generator. The first option is dependent by the utility system and will operate in parallel with it. Phase, frequency and voltage are in fact derived from the ones utilized by the utility and without a connection to this system this option cannot

operate autonomously. A second option, synchronous generator, can operate both in parallel or isolated from the utility. A more reliable system will require interconnecting the system to the grid anyways in case that digester needs to be shut down for maintenance. A synchronous system though requires higher investment costs.

- Control System. This part of the system has two finalities: first check the operation of the system and guarantee the efficiency. Second and probably more important, it is a requirement from PG&E (Rule 21) in order to connect the generator to the grid. PG&E in fact states “Prior to Parallel Operation or Momentary Parallel Operation of the Generating Facility, PG&E shall approve the Producer's Protective Function and control diagrams. Generating Facilities equipped with a Protective Function and control scheme previously approved by PG&E for system-wide application or only Certified Equipment may satisfy this requirement by reference to previously approved drawings and diagrams”.

  Another function of the system is to shut down the generation device in case the utility shuts down or if there are problems with frequency range.
- Heat and Recovery System. This component is not necessary for the technical operability of the system but can represent additional revenue, especially since almost 75 percent of the fuel is rejected as waste heat. All the biogas generation plants working at the present date are using this heat for heating or to heat water. Heat exchangers for this purpose can be easily found on the market and will allow recovering 7,000 Btu per hour for each kW of generator load, increasing efficiency of 40 -50 percent.

Electricity Generation

A farmer could choose between two different options when it comes to produce electricity: an isolated system disconnected from the utility or a parallel one.

In this analysis we will exclusively consider and refer to parallel systems.

Engine-Generator Set

The electricity generator (in parallel) allows maximizing the efficiency of the biogas production because the generator can run, as far as biogas is available, even though the farm does not need electricity. The power in fact is completely transferred to the utility owner that delivers to the farm the energy necessary for its operation through the grid as to any other customer. In this way the engine-generator can be sized for the biogas availability as opposed to farm requirements.

4.2 Applicable Regulations

Air Quality regulation

California regional agencies can independently define the level of emission into air and concede permits to those that comply in their areas of jurisdiction.

San Joaquin Valley Air Pollution Control District, in charge to define those limits in an area where many dairy activities are concentrated, has developed a specific emission limit for VOC and nitrous oxide of 12.5 tons annually. This regulation requires dairy farms to obtain an air permit when the installation of an anaerobic digester has increased the emission levels for these pollutants over the limit.

In addition, SB 1298 states that CARB has define the Best Available Control Technology (BACT) for distributed generation technologies and require its application for any new installation. BACT catalogues the emissions of each source in pounds per energy produced and indicates combined-heat-and-power (CHP) as a technology with potential environmental benefits, awarding its installation with a credit of one MWh for each 3.4 BTUs of heat recovered. Bureaucratic complications though have excluded dairy farms from the CARB certification. Biogas production from manure in fact is not included in any list of activities eligible for the award. A valid opportunity to resolve the issue could be to consider biogas production as part of agricultural operations but only farmers with 700 cows or less could benefit from this change.

4.3 Terms of the Deal with utilities owners

Nembio

PG&E's Net Energy Metering Service for Biogas Customer-Generators (NEMBIO) rate schedule is a voluntary rate for producers with adequate biogas digester equipment operating in parallel with PG&E to deliver all or a part of the producer's energy needs.

The generating facility is required to assure all the safety and performance requirements defined by the National Electrical Code and rules of the Public Utilities Commission concerning safety and reliability.

The NEMBIO tariff requires a maximum generating capacity of 1 megawatt (MW) in order to connect the generators to the PG&E grid. All biogas digester generators are required to prove, before starting producing and selling energy under NEMBIO program, that they are in conformity to the Best Available Control Technology. In addition, they must comply with the requirements of their regional air pollution control district.

NEMBIO requires PG&E to use a Time-of-Use (TOU) meter capable of separately registering the flow of electricity in two directions. The meters usually installed at residential or commercial buildings are not bi-directional and so farmers that decide to start producing electricity must adequate their system and be responsible for all expenses involved in purchasing and installing a new meter.

PG&E collects the readings from the load used in the farm by all the eligible metered Time-of-Use (TOU) accounts connected with the farm's operations reported in the interconnection agreement and then defines the NEMBIO charges and/or credits annually.

The NEMBIO agreement requires all the TOU metered service account(s) to be located on property adjacent to the NEMBIO dairy facility including those accounts associated that serves for milking operations, milk refrigeration, or water pumping. All these accounts will need to be registered under the same account name and ownership and will need to be covered by a liability insurance for the all time the system will be operational[73].

Billing Process

Biogas Customer-Generator is billed monthly for all charges other than the Generation Rate Component charges on all eligible Aggregated Metered Service Accounts.

At the end of each twelve monthly billing cycles, PG&E performs a so-called “reconciliation”. On this date PG&E provides the Customer-Generator with information regarding energy (kWh) consumption and energy (kWh) exported.

In this way NEMBIO customer-generators obtain a clear bill that totals 1) all Generation Rate Component charges for the Relevant Period; 2) all Eligible Generation Credits for the Relevant Period; and 3) all other charges due in that billing cycle of the Relevant Period.

The “Eligible Generation Credit” equals the littlest of 1) all monthly Generation Rate Component charges for the Relevant Period, including in the case of a dairy operation the Generation Rate Component charges associated with accounts eligible for Special Condition 4; or 2) the absolute value of all monthly Eligible Generation Credits for the Relevant Period.

Farmers will not be billed for stand-by charges in the monthly billing cycle except for Multiple Tariff Facilities interconnected. [64]

Net Metering Regulation for over-production

Net Metering is a billing deal stipulated between PG&E as utility owner and the farmer that define in which terms the biogas producer will be compensate for the electricity produced.

PG&E indeed as always refused in the recent years to stipulate agreements with biogas producer for direct purchasing of energy defining a certain value for kWh. In fact PG&E currently monitors the energy inflow received from the farm monthly and on this base calculates the so called “energy credit”.

At the end of each month the balance between demand and supply is determined and in case the production exceeded the energy consumption of the farm, PG&E correspond a overproduction credit [13 page 26]. The paid overproduction though is highly restricted to 100 percent of on-site needs for the year, while any other kWh over this level does not generate any revenue for the farm but only a marginal benefit for PG&E.

This term of the agreement represents the main burden to on-site electricity self-production from anaerobic digestion and can cause two different consequences both extremely detrimental for the good result of the project.

Farmers already producing enough biogas to compensate their energy needs will not try to reach the maximum efficiency of the technology or increase their cattle because this will not bring any additional benefit to them.

In other situation producers already producing over their consumption level could be lead to vent the extra biogas produced instead than invest in larger generators.

On a large scale this Excess Power regulation can greatly reduce the CO_2 free electricity from biogas produced in California and seems frankly incoherent with PG&E statements of reaching 20% renewable energy within 2010.

A recent interview of Mr. Langerwerf a farmer from Durham, North California, has shown how a different kind of deal could make this production more efficient and valuable for both parties. Producing Biogas since 1982 with his plug flow digester and cattle of 400 cows Langerwerf farm is able to produce 40,000 ft3/day of biogas with which he powers an 80 kWh generator. The particularity of this case, one of the first pilot projects, is that PG&E accepted to pay 7¢ per extra KWh produced (PG&E charges in North California between 13¢ to 21¢ per kWh). This has guaranteed an extra income of $1500 a month to the farmer for the last 15 years and has increased the amount of clean energy for PG&E that even makes a large margin per kWh [66].

Recently PG&E has reopened the option of direct purchasing electricity from biogas producers through bilateral agreements. In the last five months two purchasing contract of 10 years have been signed between PG&E and two dairy farms respectively in Kings and Fresno Valley. The two projects, operative within 2008, have secretive economic terms and so do not allow a comparison with previous cases and still remain the only two recent episodes.

Renewable Energy Credit

A Renewable Energy Credit (REC) represents the environmental and renewable attributes of renewable electricity as a separate commodity from the energy itself. A REC can be sold either "bundled" with the underlying energy or "unbundled" into a separate REC trading market.

California law (Public Utilities Code §399.12) defines a REC as [67]:

"*A certificate of proof, issued through the accounting system established by the Energy Commission… that one unit of electricity was generated and delivered by an eligible renewable energy resource*."

Renewable energy credits include all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource. Currently, only renewable power bundled with RECs can be used for Renewables Portfolio Standard (RPS) compliance – unbundled RECs do not count for RPS compliance.

In general, RECs can be traded in voluntary markets or compliance markets. In the voluntary market, any company that wishes to claim that it is powered by clean energy may buy non-renewable power from its local energy provider and also buy an equivalent amount of RECs that have been "unbundled" from renewable energy produced elsewhere. In some RPS compliance markets, the load serving entities can use unbundled RECs, rather than actual renewable energy, to comply with their RPS goals. In either case, once the RECs are unbundled from the energy, the energy is considered null (non-renewable) power [68].

When in 2004, California Government created the Renewable Energy Credit demonstrated to be willing to enact the most far-reaching renewable energy policy in the United Sates. The fundamental feature of California's new program is to require to all major utilities in the state to buy 1 percent more renewable energy each year so they obtain 20 percent of their total electric supply portfolio from renewables by 2017 (then rearranged to 2010). Under this rule, the utilities must use a bidding process for selecting renewable resources, and all generators selected will be offered long-term power purchase contracts (10 to 20 years). The utilities must pay renewable generators a contract price based on the cost of a new conventional generating resource, and the state will separately pay renewable generators an amount intended to cover any "above-market" costs [13 page 30].Renewable Energy Credits represent a fundamental element for the diffusion of biogas based power production.

IOUs like PG&E in fact are mainly interested in purchasing power from biogas producers because this help them to move toward the 20 percent power from renewable required them from California’s State.

The ownership of these credits would mean additional economic revenue for the dairy that could sell them on the Renewable Credit Market but PG&E firmly include the ownership of these credits in the price they pay to purchase the energy (REC are bundled with the power purchased). Although it is important to notice that REC require the conformity also with VOC and NO_x emissions standard during the burning phase and this element if not properly managed can downsize the benefits for biogas producers [13 page 28].

NO_x particularly could represent a double-cut point for electricity producers from biogas, not only resetting to zero the gain but even requiring additional fees for environmental compensation. Currently, the Methane emissions avoided through the management of manure are not awarded with RECs because they are considered as a source of revenue for the dairy farmers.

4.4 Incentives Specific to Electricity Production

AgSTAR Program

The AgSTAR program is a system of incentives, grants, loans and tax credits created by the US EPA aimed to sustain anaerobic digestion technologies and reduce methane emissions in atmosphere.

The program encourages biogas capturing and utilization in manure management as liquids or slurries offering economical and technical support to carry on a feasibility study and the successive realization.

A supplementary value of AgSTAR program is to produce a list of economical resources that farmers can consult and request once they intend to start producing renewable energy. The list is divided for Federal and State specific funds with all the information on how to apply and on the requirements [65 page 17 and 19]

Federal Incentives

Environmental Quality Incentives Program (EQIP)

USDA’s Natural Resources Conservation Service administrates the EQIP funds promoting agricultural activities in respect of environmental quality. The incentives are distributed prioritizing areas with high environmental issues providing up to 75% of the costs of certain conservation practices with a contract length of one year after the installation of the last system up to 10 years.

Local Conservation agencies define which projects are eligible for the grant and choose usually the most cost effective and environmental efficient projects. The financial requirements of this project restrict the access to this fund to company that do not exceed a gross income of $2.5 million, unless the 75% of this income derives from farming, forestry and ranching

Self generation Incentive Program (SGIP)

Since 2001 Assembly Bill 970 (extended to January 2012) created a portfolio of incentives oriented to promote renewable power generation addressing specifically to solar, wind and fuel cells applications but including even not renewable-distributed options.

Biogas projects have been eligible for SGIP incentives for the past seven years but now despite the prolongation of the program will not be included in the program starting from January 2008.

The Assembly Bill 1064, in progress, will try to extend the incentives even to waste gas including in this category even the one obtained from anaerobic digestion. In order to receive incentives the waste gas project should demonstrate to produce air emission benefits on a local scale [13 page 27]. The AB 1064 was not passed in the December 2007, and as a consequence biogas systems are no longer eligible for SGIP grants

Chapter Five: Farms Introduction

This report will study five of the ten dairy farms object of "Dairy Methane Digester System Program Evaluation Report" (WURDCO) published in 2006 proposing 5 modified scenarios of analysis. Farms studied in this report are:

Hilarides Dairy; Lindsay, Tulare County, CA;

Castelanelli Bros. Dairy; Lodi, San Joaquin County, CA;

Koetsier Dairy; Visalia, Tulare County, CA;

Inland Empire Utilities Agency (IEUA); Chino, San Bernardino County, CA;

Eden-Vale Dairy; Lemoorre, Kings County, CA;

Table 5.1 "General Information Dairies"

Dairy Name	Number of Lactating and total herd	Manure Collection Method	Location
Hilarides Dairy	6,000	Flush	Lindsay ,Tulare County
Castelanelli Bros. Dairy	1,600	Flush	San Joaquin County
Koetsier Dairy	1,266	Scrape	Visalia, Tulare County
IEUA	7,931	Mix Scrape	Chino, San Bernardino County
Eden-Vale Dairy	800	Scrape	Lemoorre, Kings County, CA

From WURDCO

Utilizing these five farms we tried to represent as well as possible the spectrum of productive options in California in terms of size of the farm, manure collection method and location. It is complicated to try to delineate policies, address issues and especially compare technologies in a sector where each single project has unique conditions and specific circumstances. This becomes even more intricate when the boundaries of applicability for the findings include the whole State of California.

We are confident though of having portrayed widely this sector and the diverse variables that can come into playing when a farm produces energy.

The following data collected from WURDCO and already partially used in the subsequent study by PERI, list Biogas Production Data for the five farms analyzed.
In order to have better understanding of the production process and clarity of the values utilized for the analysis please refers to ANNEX A where the information on each single farm reported in detail.

Table 5.2 " Electricity Generation Incentives"

Dairy Name	Grant	Buy down	Incentive payments	Personal Investment	Electricity Generation Final System Cost $	Investment Cost per kW installed in $/kW
Hilarides	$0	$500,000	$0	$739,923	$1,239,923	2,480
Castelanelli	$0	$320,000	$0	$562,136	$882,136	5,513
Koetsier	$0	$0	$190,925	$1,170,162	$1,361,087	5,235
Eden-Vale	$0	$300,000	$0	$502,810	$802,810	4,460
IEUA	$175,000	$0	$773,175	$2,603,273	$3,551,448	6,308

The investment costs that each farm had to sustain to develop a complete system to generate electricity can be found in the table above. Electricity generation system and anaerobic digestion equipment are both included in the final cost.
Table 5.2 shows the different typologies of grants received by each farm and indicates the amount of capital to be invested by the private owners to install the system. Payback periods for all the five case studies have been calculated both on the private capital invested and on the total capital required, in order to describe the economic performances of the project in case no incentives would be available.

Typology of Digester:

It is interesting to observe how investment cost per kW installed varies in relation with the type of digester installed. Lagoons are usually cheaper; this technology indeed is more diffuse and awards larger projects with lower cost for kW installed being most of the expenses concentrated in the general construction and gas handling system (economy of scale can play a fundamental role here).

Plug Flow digesters requires higher investment cost on average having to face charges for obtaining permits even five times more expensive than a covered lagoon. These systems are more case specific designed and so economy of scale does not seem to offer large advantages.

For what concern with Modified Mix Plug Flow we can only refer to IEUA case. This typology of equipment is created for larger quantities of manure obtained from more than one farm and requires larger investments. The efficiency of the overall system is then even more important in order to recover the capital cost. Hilarides farm stands out with a very low cost per kW due to the choice of using refurbished equipment instead than purchasing new one. Analyzing the ratio between the incentives received and the power installed (or the final cost of the equipment) we can see a certain unconformity among the case studied. Particular evident is the low founding received from Koetsier ($190,000) for a project cost of over $1,300,000 when most of the other farms received almost 50% of their investment refunded. This can be explained by an extraordinary expansion of the final cost compared to the expected cost (initially only $363,087). Koetsier in fact applied for funding only for refurbish an existing digester but while the project was on-going the all old system needed to be substituted.

Table 5.3 "Digesters Data: Digester Inflow, Biogas Production and Biogas per cow"

Dairy Name	ESTIMATED DIGESTER INFLOW			Average Biogas Production (cubic feet/day)	Average Biogas Production (cubic feet/day/cow)
	Total (gallons/day)	Dry Total Solids (pounds/day)	Dry Volatile Solids		
Hilarides	180,000	13,368	7,074	232,681	38.8
Castelanelli	541,495	49,210	19,003	89,148	55.7
Koetsier	30,000	20,044	15,663	44,193	34.9
Eden-Vale	15,000	18,843	13,427	40,360	50.5
IEUA	34,580	3,458,000	27,664	113,189	14.3

From WURDCO

The analysis of average biogas production (per cow) underline that even though Plug-in-flow technology is supposed to guarantee a higher yield, this is not practically demonstrated in our analysis. Castelanelli with a lagoon system of manure collections obtains the greatest result in terms of overall biogas efficiency while IEUA achieved very low average production due to the nature of its system. IEAU in fact collect manure from six farms located nearby its plant. Despite an agreement between parts though the farms are not currently delivering the amounts agreed decreasing drastically the biogas obtained and impacting, as we will see in scenario 1, on the payback period of this investment.

Chapter Six: Analysis and Discussion

6.1 Electricity Production Base Scenario 1

Assumptions:

a. Payback Periods are calculated using real productive data and investment cost and running costs are the ones indicated by the farmers for the time frame 2005-2006

b. Electricity is generated from biogas through the use of a generator.

c. IOUs do not offer extra compensation to the farmers for the energy produced over the farm consumption rate.

d. All the dairies received grants from the California Energy Commission to install a generation system and an anaerobic digester.

e. Electricity bill offset and extra savings are the ones communicated by the farmers for the period in object.

Analysis

Table 6.1.1 "Productive Data Base Case Scenario 1"

Dairy Name	Electricity Generation Final System Cost	Operation Costs $/YEAR	Electricity Used kWh/YEAR	Base Scenario 1 kWh/year	Electricity Bill Offset in $/YEAR from WURDCO
Hilarides	$1,239,923	$24,000	2,361,660	3,370,464	146,520
Castelanelli	$882,136	$11,400	910,788	1,054,560	32,736
Koetsier	$1,361,087	$27,000	663,180	539,892	24,684
IEUA	$3,551,448	$1,404,708	14,309,712	1,451,640	79,968
Eden-Vale	$802,810	$18,000	294,504	453,168	11,424

The obtained savings for the year 2005-2006 confirm a great diversity between the projects regardless of the IOUs operating in the area.

First of all it is important to denote that only IEUA obtained revenues from heat recovering gaining in this way an additional source of payback period reduction. IEUA payback period is aggravated though by complex and expensive system organized to receive daily, important amounts of manure from six local farms.

Hilarides instead was the only one using the power generated in the farm managing in this way to obtain savings for $10,476 per month. This source of income made Hilarides the only project able to guarantee an economically feasible payback period in this scenario.

Koetsier, IEUA and Eden-Vale decided to produce energy under the net metering deal, resulted extremely uneconomical due to a combination of diverse variables but mostly affected by the unfavorable NEMBIO conditions.

The energy sent to the utility in fact is valued at the energy rate portion of the full retail rate and so it is charged per kWh consumed and varies by time of the day and season (demand-supply fluctuation of prices) without though including the basic demand charge or customer charge. This point is particularly important when the profitability of a net metering system is evaluated.

In the Castelanelli case, a project that obtains a relatively acceptable payback period (10.59 years), the demand charge is a consistent share of the total amount of a farm electric bill and the credits obtained cannot reduce how much the farmer has to pay for this specific charge.

Castelanelli farm’s electricity bills for instance, dated before the digester was installed showed that the 25% of the amount was for demand charge.

Now even though the 160kW generator produces an amount of energy 30% over the in-farm electricity need (this despite the fact that almost half of the biogas produced in the lagoon is still flared) that 25% is still intact in the electricity bill, representing now the 80% of the total value.

Castelanelli farm like Koetsier, IEUA and Eden-Vale have more than one meter connected with the generator and included in the NEMBIO agreement. PG&E scan the activity of each of these meters every 15 minutes (SCE does it every 30 minutes) and calculated the demand charge for the month measuring the maximum kilowatt input recorded during this 15 minutes interval. So if for any reason, maintenance or break down, the system is not producing power for longer than 15 minutes (30 minutes SCE) and the farm relies on the energy from the grid, the demand charge become equal to the one that normal customer (same energy demand but not producers of energy) have to pay.

IEUA for the specific conditions of its system is the only case where an efficient production could even under Net Metering (no value for extra power) bring economic benefits due to its large energy demand. IEUA is the Inland Empire Utility Agency and has a primary object the production and distribution of drinkable water in the Chino area. For this reason IEUA has a very high-energy demand compared with a normal farm with the same herd. The animals are not managed or situated inside the IEUA but in private farms in the surroundings of the site.
Under the current system the value of electricity generated to offset on-site demand enable IEUA to gather only $79,968 a year, while without a demand charge this value would increase to $565,819 a year. Even a smaller size farm as Castelanelli with a large energy demand per capita (569 kWh/year per animal) would benefit even just from a more fare bill offset system. Assuming basic value of 5 cents/kwh the farmer in this case would save $106,548/year instead than the actual $32,736/year.

"Electricity Used" and 'Actual Electricity Produced" shows that three farms (Hilarides, Castelanelli and Eden-Vale) produce electricity over their annual consumption. A rough calculation, confirmed by the farmer, showed that Castelanelli looses on average $7,000/year in electricity sent to the grid and for which Castelanelli doesn't receive any compensation (not even including the amount that the farmer prefer to flare instead than process and insert without compensation in the grid). This loss is even more impacting considering that such amount would compensate for the increased demand charge, reducing the payback period to 8.51 yr.

Table 6.1.2 "Payback Time Scenario 1"

Dairy Name	Scenario 1 Payback Time (year) with Incentives	Scenario 1 Payback Time (year) without Incentives
Hilarides	5.21	8.63
Castelanelli	10.59	27.31
Koetsier	48.50	56.23
IEUA	50.12	61.98
Eden-Vale	45.59	71.85

Environmental Outlook:

The lack of compensation for extra power has an impact not only on the financial aspect of the projects but even on the environmental performances of the system. As stated above in the section dedicated to the benefits obtainable from an anaerobic digester, methane represents a considerable impact coming from cattle that can be offset with the use of a digester. All the projects though in order to not incur in running cost that would not produce any economic benefit prefer to flare the extra biogas produced once the production equal demand. The table below shows the actual quantities flared during the 2005-2006 period.

Considering a GWP for methane of 21 times CO_2 GWP, these farms flaring these amounts of methane reverse the environmental performances of this system, losing the purpose for which these equipments were installed in the first place.

Table 6.1.3 "Biogas Flared Amounts"

Dairy Name	Base Case Scenario 1 Biogas/YEAR	Base Biogas Scenario 1 cf/day	Quantity Flared	Quantity Flared in cf/day
Hilarides	84,928,565	232,681	20% -40%	69,804
Castelanelli	32,539,020	89,148	40% - 50%	40,117
Koetsier	46,064,825	126,205	15% - 40%	34,075
IEUA	41,313,985	113,189	40% - 50%	50,935
Eden-Vale	32,179,860	88,164	0% - 5%	2,204

The main purpose of the incentives received by the farmers from the California Energy Commission in fact is to sustain the diffusion of renewable energy. The base case scenario though cannot be considered environmentally friendly from an emissions point of view due to the flaring practice.

Four of the farms flare 1 cubic foot of methane for every 1,000 kWh they produced, this without even including the emissions released by the generator burning biogas.

Findings:

- ***Electricity production from biogas can be economically feasible under the current scenario only when:***
    - ***Farms receive incentives for at least half of the capital costs***
    - ***Farms produce as much electricity as it consume***
    - ***Biogas yield can be controlled directly and maximized***
    - ***Farms utilize energy on-site reducing in this way the impact of demand charge on the overall balance***
- ***Use heat recovery can be useful to reduce even more the payback time***
- ***Incentives are fundamental to all the projects and without incentives any of the observed projects would be economically stable.***
- ***No direct connection has been identified between system performances and the IOUs operating.***
- ***Demand charge is the reason for which many projects resulted economically inefficient***

6.2 Modified Electricity Production Scenario 2

Assumptions:

a. Farms increase their production to the maximum level of electricity generation considering their installed power. Extra power first offsets the energy demand of the farm; once the demand is covered the farm sells extra power to the IOU, obtaining additional revenues.

b. Energy produced by the farmers over the demand rate is assumed to be paid by IOUs 7 cents/kWh (This is the price currently discussed by CPUC)

c. No extra power is required to be installed

d. No additional investment cost is required

e. An increase of 20% in running costs is considered due to an increase in operating hours. The base values on which the increase is calculated are taken from WURDCO.

f. Biogas flaring is reduced to zero because farmers are pushed to maximize the electricity production utilizing all the biogas in the digester

g. All the dairies receive the same grants as in real case scenario 1 to install a generation system and an anaerobic digester.

h. Electricity bill offset and extra revenue are the ones communicated by the farmers for the period 2005-2006. Those have been added to the “calculated extra revenues” considered in this scenario.

Analysis

Table 6.2.1 “Comparison Biogas Yield Scenario 1 and Scenario 2”

Dairy Name	Max Biogas Available in Scenario 1 (cf/year)	Scenario 1 Biogas used for power (cf/year)	Scenario 2 Possible Yearly Generation kWh/year (*1)	Scenario 1 Electricity Produced kWh/year
Hilarides	84,794,124	59,355,887	4,380,000	3,370,464
Castelanelli	32,503,500	14,626,575	1,401,600	1,054,560
Koetsier	16,132,800	4,355,856	2,277,600	539,892
IEUA	41,891,628	31,174,188	4,931,880	1,451,640
Eden-Vale	14,618,856	14,180,290	1,576,800	453,168

(*1)(assuming generator works at 100%)

We hypothesized that once a value for extra power was introduced; all the cases studied confirmed an increased electricity production. Koetsier Dairy and Eden-Vale Dairy for instance would be able to enlarge their annual production from 539,892 kWh/year and 453,168 kWh/year to 2,277,600 kWh/year and 1,576,800 kWh/year. These objectives could be obtained without any extra power installed but simply using efficiently the biogas already produced and avoiding flaring.

This extra production would guarantee to the two farms an additional income of $96,865.20 and $76,937.76 a year that would help to short greatly the payback time of the two systems.

Table 6.2.2 “Revenues for Scenario 2 and Electricity Consumptions”

Dairy Name	Scenario 2 Electricity Used kWh/YEAR	Electricity Bill Offset in $/YEAR	Scenario 2 Revenues from Increase Power Production $/YEAR
Hilarides	2,361,660	146,520	141,283.80
Castelanelli	910,788	32,736	34,356.84
Koetsier	663,180	24,684	113,009.40
IEUA	14,309,712	130,444.80	0.00
Eden-Vale	294,504	11,424	89,760.72

IEUA would be able to pass from 1,451,640 kWh/year to 4,931,880 kWh/year finally optimizing the performances of its system. IEUA though, for the reason indicated above even maximizing its production would only offset energy bill but would not produce direct revenues. The net metering system and the demand charge reduces the indirect profit IEUA could achieve, resulting in another uneconomic payback time (13.49 yr and 17.70 yr). In addition, the running costs (reported by IEUA) kept being a large part of the overall expenses, compared with the other systems, stretching even more the time for the investment to return.

Analyzing the performances of the other four dairies we see a notable reduction of all the payback periods, especially for Koetsier and Eden –Vale that in the base case scenario showed major economical issues. Four of the five projects would obtain payback periods within 10 years (assuming the availability of incentives) and will be able to transform this technology primarily oriented to gain environmental benefits, into a more fruitful additional source of revenues.

Eden-Vale in particular could pass from a five decades payback time to six years, just using efficiently the equipment and the biogas digested. The base scenario in fact demonstrated how Eden dairy was producing sufficient to electricity to offset its bill generating only a third of the possible power and already delivering to the grid for free 200,000 kWh/year. Operating the generator with a higher efficiency would not only produce more energy but even reduce switch-off time on which base the demand charge is calculated. Demand charge represents an important source of loss that in this way would be partially overcome.

Table 6.2.3 "Payback Times Scenario 2"

Dairy Name	Scenario 2 Payback Time (year) with Incentives	Scenario 2 Payback Time (year) without Incentives
Hilarides	2.67	4.41
Castelanelli	5.20	13.36
Koetsier	8.73	10.12
IEUA	32.88	40.15
Eden-Vale	5.18	8.15

The analysis of the payback time of the projects without external incentives though demonstrates a very weak balance between overall cost of the equipment and annual revenues/savings. Without grants only Hilarides is able to maintain a payback period smaller than five years this due to a large electricity production, a low energy demand and an even lower capital cost. Hilarides is able to function like a small power plant through:

- Maximization of the producible energy
- Lowest capital cost per kWh installed
- Highest biogas production (60.5 cf/day/cow)

Environmental Outlook:

The scenario 2 can obtain a reduction to zero of the flared biogas. Farmers have an incentive to run their generator at the maximum load factor and to produce low-CO_2 electricity avoiding in this way to release excess gas into atmosphere. No environmental or air quality regulation are applied to obtain this result but a simple economic policy (incentives to production).

Even from the IOUs side this adjustment in the Net Metering deal would bring positive outcome. California in fact required all IOUs to reach a share of 20% renewable based energy within 2010. These extra kWh will help to reach, even in a small part, this goal and would make the projects more coherent with the mission of the California Energy Commission that financed them.

Findings:

Electricity production from biogas can become more economically feasible when:

- ***Farms receive compensation for extra power sent to the grid (7cents/kWh is the propose amount is this scenario and in the following two scenarios because this amount is the price proposed by CPUC in the AB1969 currently under discussion).***
- ***Farms produce enough electricity to at least offset its electricity bill.***
- ***Generators are used at full load avoiding having the system down and a consequent increase of the demand charge.***
- ***Farms utilize energy on-site reducing in this way the impact of demand charge on the overall balance.***
- ***Maximization of production will produce an improvement in the environmental performances avoiding biogas flaring to take place.***
- ***Incentives are fundamental to all the projects with the exception of Hilarides Dairy.***

- ***The lack of grants would allow only three of the five systems to be economically stable by themselves with only one obtaining a payback period under five years.***
- ***Large systems with normal energy demand, use of energy both on-site and in Net Metering and able to maximize their overall efficiency are the best candidates for this type of production.***

6.3 Modified Electricity Production Scenario 3

Assumptions:

a. Daily biogas yield for each farm is hypothesized to be at least 60 cubic feet per cow per day. In case a farm has an actual yield higher than 60 cubic feet/day/cow the real value is considered.

b. Farms increase their production to the maximum level of electricity generable with new biogas inflow. Extra power first offsets the energy demand of the farm; once the demand is covered the farm sells extra power to the IOU, obtaining additional revenues.

c. Energy produced by the farmers over the demand rate is paid by IOUs 7 cents/kWh

d. No demand charge is applied. The avoided cost due to electric bill offset is calculated assuming a value of 5 cents/kWh, instead than 7 cents/kWh in order to include roughly interconnection and insurance cost.

e. In scenario 3 extra power might be installed to increase the generation system capacity in consideration of additional biogas inflow.

f. Additional investment cost is required for installing the extra power and is calculated using the values of $/installed power reported by WURDCO for each farm. 40 percent discount rate is assumed due to economy of scale.

g. An increase in running costs is considered for some candidates in relation to their increased power due to an increase in operating hours

h. Biogas flaring is reduced to zero because farmers are pushed to maximize the electricity production utilizing all the biogas produced in the digester

i. All the dairies received the same grants from the California Energy Commission to install a generation system and an anaerobic digester, as for base scenario.

Analysis

Table 6.3.1 "Scenario 3 Biogas Production and Averages per cow"

Dairy Name	Scenario 3 Biogas Production (assuming 60cf/cow/year)	Scenario 2 Biogas/Y cf/year	Average Biogas Production (cf/day cow) from WURDCO
Hilarides	131,400,000	84,972,000	38.8
Castelanelli	35,040,000	32,528,800	55.7
Koetsier	27,725,400	16,126,941	34.9
IEUA	173,688,900	41,395,855	14.3
Eden-Vale	17,520,000	14,746,000	50.5

Base Case Scenario 1 already showed how, without a price for extra power produced in the dairies, most farmers decide to not maximize their yield, but just generate enough electricity to equal their demand. Most of the farmers interviewed for the WURDCO report in relation with the scenario 1, were content for the reduced odor and the increased water quality they obtained with anaerobic systems. In the scenario 3 we want to improve the generation side and compare the additional benefits with the increased costs.

The Case Scenario 3 proposes an increase of biogas yield to a value of 60 cubic feet per day for each cow (this yield can be obtained easily collecting and managing manure in more efficient way) and a price of 7 cents/kWh for electricity sent to the grid over the energy demand of the dairy.

In order to quantify the additional power that can be produced by each farm, a system efficiency ratio has been calculated (Table 6.3.2 below). From the power obtained for cubic feet of biogas in the actual case for each farm-generator, we assume a "Possible Additional Generation".

The proposed increased fuel rate will require uploading the installed power in order to generate the new electricity flow.

Table 6.3.2 "Additional Generation Levels, Total Maximum Electricity Production"

Dairy Name	Generator Name Plate Capacity kW	Yearly Generation kWh/year (Scenario 2)	System Efficiency cf biogas/kWh	Scenario 3 Possible Additional Generation Kwh	Scenario 3 Possible Electricity Production (kWh/year)
Hilarides	500	4,380,000	19.40	2,393,196	6,773,196
Castelanelli	160	1,401,600	23.21	108,203	1,509,803
Koetsier	260	2,277,600	7.08	1,638,045	3,915,645
IEUA	563	4,931,880	8.39	15,761,323	20,693,203
Eden-Vale	180	1,576,800	9.35	296,626	1,873,426

The values of increases installed power required can be found in the Table 6.3.2 above and have been used to calculate the additional capital cost necessary. The cost for installed kW is the same reported by PERI for the installation of the first system (base case scenario 1) even though a 40 percent have been subtracted in order to do not include engineering and project cost that are usually (within certain limits) fixed and not directly proportional to the power installed.

Table 6.3.3 "Electricity Production and Extra Power to be Installed Scenario 3"

Dairy Name	Electricity Used kWh/YEAR	Electricity Produced Yearly (kWh) Base scenario 1	Investment Cost per kW installed in $/kW	Scenario 3 Electricity Bill Offset (*1) in $/YEAR	Scenario 3 Revenues from Power Production (*2) in $/YEAR	Extra Power to be installed to produce maximum kWh available
Hilarides	2,361,660	3,370,464	2,480	118,083	308,807.51	359
Castelanelli	910,788	1,054,560	5,513	45,539	41,931.02	32
Koetsier	663,180	539,892	5,235	33,159	227,672.53	237
IEUA	14,309,712	1,451,640	6,308	776,854	446,844.36	2,062
Eden-Vale	294,504	453,168	4,460	14,725	110,524.52	58

*1(if offset power is valued 5 c/kWh) *2(assuming 7 cents/kWh)

Hilarides and IEUA, the two biggest cases in terms of herd, are to be the more advantaged by an increase of biogas yield. In the case of IEUA the very poor results obtained in the real scenario 1 can be explained in part by a very low biogas yield. Despite almost 8,000 cows IEUA gather less biogas (an average yield of 14 cubic feet of biogas per day/animal) and obtain annually only a third more biogas than Castelanelli with its 1600 animals. These values explain even more the uneconomic profile of IEUA project if compared with the capital cost required to install the system. An average yield of 14cf/day/cow allow IEUA to produce with a 563 kW generation system only 1,451,640 kWh/year while Castelanelli inject into the grid 1,054,560 kWh annually with a 160 kW generator. The analysis of the singular performance in this modified scenario 3 shows how all the farms observed could improve their biogas yield and consequently increase their energy production. IEUA again could add to its production of Base Scenario 2 (where generator efficiency was maximized) another 14 mil kWh annually. This result seems to confirm that IEUA system was largely undersized at the time of the installation for the number of available animal producing manure. This could have been caused by the necessity to keep the project budget within certain restrictions regardless of the actual productive data. The increased power in fact, as showed in the table below, will require consistent investments for IEUA to gain the greatest benefit from this scenario.

In the case of Castelanelli and Eden-Vale the small increase in power obtainable demonstrate that the systems were properly sized in relation with a normal estimated biogas yield. For both these dairies though despite a small relative increase in electricity generated, a better payback period was achieved compared with the precedent scenarios.

Table 6.3.4 " Investment Costs, Maintenance Costs and Personal Investment for Scenario 3"

Dairy Name	Maintenance Cost	Scenario 3 Investment Cost	Scenario 3 Personal Investment	Capital Cost installed power ($/kW) from PERI	Economy of scale decrease factor (40%)
Hilarides	$33,600	$1,596,135	$1,096,135	2,480	0.4
Castelanelli	$13,200	$951,609	$404,213	5,513	0.4
Koetsier	$40,500	$1,856,642	$1,665,717	5,235	0.4
IEUA	$2,107,062	$8,753,616	$7,805,441	6,308	0.4
Eden-Vale	$18,000.0	$905,612	$605,612	4,460	0.4

The payback table below shows an impressive improvement in all the cases obtaining an average value of 5.41 years with incentives and of 7.68 without incentives. The “without incentives” index is particularly important to identify the real possibilities for this technology to take off autonomously. Only Castelanelli that received incentives for more 65% of its investment costs obtains values over 10 years in these conditions, determining an underlying instability of the project when financial sustain is not given.

Table 6.3.5 “Payback Time for Scenario 3”

Dairy Name	Scenario 3 Payback Time (year) with Incentives	Scenario 3 Payback Time (year) without Incentives
Hilarides	2.65	3.82
Castelanelli	4.77	11.03
Koetsier	6.54	7.27
IEUA	8.10	8.88
Eden-Vale	4.98	7.37

Koetsier and IEUA reduce of two times their payback periods increasing their previously very low ratio of kWh produced for dollar invested. These two companies had to cover a very large share of their cost with personal funding for reasons already explained above. These new performances achieved demonstrate that this technology is not exclusively applicable when grants can support its development but even when the flows are optimized and the system properly sized.

Often when the installation of this kind of equipment is proposed to farmers (usually by local administrations to reduce environmental impact), the normal tendency is to size the system in relation to the funding available reducing as much as possible the private investment necessary. The real productive inputs obtainable with herd and eventual expansion are not taken in consideration. This missing link is partly responsible for most of the systems to be inefficient in the base scenario.

Environmental Outlook:

The Modified Baseline scenario 3 could obtain the same reduction of flared biogas than scenario 2. Farmers even in this case have an incentive to run their generator at the maximum load factor and to produce low-CO2 electricity avoiding in this way to release excess gas into atmosphere. The increase biogas production could even result in an increase emission due to unintentional losses. Those amounts are difficult to quantify with a secure pattern and so have not been considered

IOUs would increase the amount of eligible renewable energy from a total of 4 mil kWh/year in scenario 1 and 14 mil kWh/year in scenario 2 to maximum of 35 mil kWh/year in scenario 3, with obvious positive implications in terms of achieving the 2010-CEC goal.

Findings:

Electricity production from biogas become economically robust for all the cases studied in scenario 3 when:

- ***60 cubic feet of biogas are obtained daily from each cow***
- ***Farms receive compensation for extra power sent to the grid (7cents/kWh)***
- ***Farms produce enough electricity to at least offset its electricity bill***
- ***Generators are used at full load avoiding having the system down and consequently increasing the demand charge***
- ***Farms utilize energy on-site reducing in this way the impact of demand charge on the overall balance***

6.4 Biomethane Upgrading Scenario 4

Assumptions:

a. Biomethane is obtained from the same anaerobic system utilized for electricity generation. The cost of digester and connected equipment is accounted equally as per electricity generation.

b. Biogas yield is assumed to be the same as Modified Electricity Generation Scenario 2. Inflow assumed is the normal production rate including the amount normally flared.

c. Upgrading Costs and Connection Costs are assumed after market research and compared with values of PERI report.

d. Payback Periods are calculated using real productive data (biogas yield) while running costs are hypothesized increasing of 20 percent values of electricity generation system.

e. Biomethane produced is assumed to be sold to IOUs for 6$ per MM Btu.

f. Grants, incentives and pay-down funds are for the same amount as per previous scenarios.

Analysis

Table 6.4.1 "Biomethane Upgradable in Scenario 4"

Dairy Name	Scenario 4 Biogas Production cf/daily (assuming same yield of electricity production)	Actual Heat Content (MM Btu/Mcf)	Scenario 4 Biomethane Upgraded in MMBtu/day	Base Case Potential Biomethane Upgraded in MMBtu/YEAR
Hilarides	232,313	0.523	121.50	44,347.33
Castelanelli	89,051	0.625	55.66	20,314.69
Koetsier	44,199	0.557	24.62	8,985.97
IEUA	114,772	0.648	74.37	27,145.77
Eden-Vale	40,052	0.552	22.11	8,069.61

The results of this scenario can be used for a comparison both with scenario 1 and scenario 2. No scenario with the same amounts of biogas as per scenario 1 (with flaring) is considered in the biomethane alternatives. This because a situation where biogas is flared would not make sense when the final aim of the process is to upgrade biomethane.

Biogas yield is the one reported by the farmers for the period 2005-2006 while the heat content has been obtained from PERI report that conducted a similar analysis with diverse assumptions.

Table 6.4.2 "Costs for Biomethane Upgrading Technology part 1"

Dairy Name	Interconnection Tap to Utility	Controls & Meters	Unique Interconnection Facilities	Distance from The NG pipeline in feet
Hilarides	$45,000	$35,000	$80,000	1,000
Castelanelli	$45,000	$35,000	$80,000	2,700
Koetsier	$45,000	$35,000	$80,000	1,000
IEUA	$45,000	$35,000	$80,000	1,000
Eden-Vale	$45,000	$35,000	$80,000	1,000

All the connection, upgrading, purification and civil engineering costs connected with the upgrading biomethane system are listed in table XXX and table XXX. These values are obtained from PERI report and from assumptions developed under the advice of PG&E technical office. This technology is not very spread in California (only one company is currently working to install an upgrading system) and so the financial assumptions refers not to actual costs but to hypothetic cost that the farms would have to sustain in case they decided to opt for biomethane upgrading instead than electricity generation.

Table 6.4.2 "Costs for Biomethane Upgrading Technology part 2"

Dairy Name	Dedicated pipe line (400$/foot)	Gas Clean-up and Processing	Monitoring	Pipeline Quality Gas Additional Capital Cost	Lagoon System
Hilarides	$400,000	$720,000	$90,000	$181,566	$366,268
Castelanelli	$1,080,000	$570,000	$90,000	$400,285	$311,044
Koetsier	$400,000	$480,000	$90,000	$584,247	$271,230
IEUA	$400,000	$570,000	$90,000	$747,524	$2,897,063
Eden-Vale	$400,000	$400,000	$90,000	$459,318	$438,433

The main voice of cost is represented by the construction of a dedicate pipeline to transport the biomethane produced to a natural gas network. In this assumption the distance from the network is a value of uncertainty because a map of the natural gas was not publicly available and so estimations reported by PERI and California Energy Commissions have been adopted.

Table 6.4.3 " Investment Costs, Maintenance Costs and Personal Investment for Scenario 4"

Dairy Name	Total Grants	Scenario 4 Capital Cost	Scenario 4 Personal Investment	Scenario 4 Maintenance Cost per year
Hilarides	$500,000	$1,917,834	$1,417,834	$28,800
Castelanelli	$547,396	$2,611,329	$2,063,933	$14,400
Koetsier	$190,925	$1,985,477	$1,794,552	$32,400
IEUA	$948,175	$4,864,587	$3,916,412	$1,685,650
Eden-Vale	$300,000	$1,947,751	$1,647,751	$21,600

Final cost of upgrading system has been increased of 25 percent. The lesson learned from the electricity generation in fact where actual cost was 25 percent higher that estimated one, convinced us to increment the final cost of the system of the same percentage.

Maintenance cost has been estimated increasing of 20 percent the ones for electricity generation. Upgrading systems are in fact less easy to manage and more likely dependent on professional (and expensive) external assistance.

The Table below shows the potential revenues of selling upgraded biogas to the IOUs for each single dairy. The values of efficiency (cow/cubic feet of biogas obtained) become here even more important because directly proportional with the quantities produced and to the payback period. This scenario 4 once compared with the base scenario 1 of electricity generation, shows a higher benefit for the farmers because it permits to increase the revenues keeping constant the capital cost and the herd size.

Table 6.4.4 "Achievable Revenues Scenario 4"

Dairy Name	$/MMBtu of biomethane from IOUs	Scenario 4 Revenues from biomethane
Hilarides	$6.00	$266,083.96
Castelanelli	$6.00	$121,888.13
Koetsier	$6.00	$53,915.82
IEUA	$6.00	$162,874.65
Eden-Vale	$6.00	$48,417.65

Differently than for scenario 1, there is no limit to how much a farmer can produce and these values are completely independent by the in-farm energy demand.

From the Analysis of the potential revenues Hilarides Farm appears to be, even in this scenario, the one theoretically able to achieve best results. Even IEUA potential revenues show an impressive improvement when compared to the bill offset registered for the period 2005-2006, passing from less than $80,000 a year to double this value. This demonstrates that a system with the same mass inputs can produce very different results in economic terms without a radical increase in capital cost

Scenario 1 (electricity) and scenario 4 (biomethane) are the basic productive conditions and the study of their performances can give a precise idea to farmers that are on the process of installing a digester. This comparison would identify the alternative that, under these specific productive conditions, would have brought the best results.

In relative terms the scenario 4 produced better achievements both from financially (four of five dairies had shorter payback periods) and environmentally (flaring did not occur).

In absolute economical terms though none of the projects, with the only exception of Hilarides, were able to reach sustainable cash flows in neither the scenarios. Despite in fact other dairies like Koetsier and Eden-Vale reduced to a third their payback time, compared with scenario 1, the biomethane scenario 4 did not bring generally sustainable economic results.

Differently from the rest of the cases, Castelanelli biomethane upgrading in scenario 4 would increase its investment return time compared with the one obtained under base scenario 1. A system with such small production rate indeed and relatively distant from the Natural Gas network has difficulties to recover an investment cost of $2,600,000, despite the efficiency of its process. The cost of a dedicated pipeline in fact would require Castelanelli an additional $700,000 that represent for a family business a very challenging investment.

Table 6.4.5 "Payback Time Scenario 4"

Dairy Name	Scenario 4 Payback Time (year) with Incentives	Scenario 4 Payback Time (year) without Incentives
Hilarides	5.43	7.30
Castelanelli	17.03	21.52
Koetsier	11.87	13.11
IEUA	34.88	40.78
Eden-Vale	15.66	18.48

The analysis of the difference between the payback periods with or without incentives will not offer interesting indication since all the project are economically inefficient even with incentives (Hilarides not included)

Environmental Outlook:

The Biomethane Upgrading scenario 4 could obtain a reduction to zero of the flared biogas as the electricity generation system scenarios 2 and 3. Farmers still have an incentive to run their generator at the maximum load factor and to produce low-CO2 electricity avoiding in this way to release excess gas into atmosphere.

Findings:

The scenario 4 offered the following indications:

- ***Biogas yield efficiency is a fundamental requirement for a dairy to economically develop a biomethane upgrading system.***
- ***Distance from the NG pipeline is a main reason of investment cost increase.***
- ***Dairy with a large herd are more likely to obtain feasible payback time if the biogas yield is at least over 45 cubic feet/day/cow.***
- ***A value of $6/MMBtu is sufficient only when the three conditions above take place.***
- ***Biomethane upgrading regardless of the financial performances of the projects produce an improvement in the environmental performances of the systems avoiding biogas flaring to take place.***

Incentives are fundamental but are not sufficient to guarantee a good economic performance when biogas yield is not efficient.

6.5 Biomethane Upgrading Scenario 5

Assumptions:

a. Biomethane is obtained from the same digester system utilized for electricity generation.

b. Biogas yield is assumed to be the same as Modified Electricity Generation Scenario 3 where biogas yield is maximized to 60 cubic feet/cow/day.

c. Upgrading and Connection costs have been assumed after market research and from PERI report. The values indicated by PERI referred to biogas yield as scenario 2 and so have been increased of a percentage proportional to the augment in biogas yield.

d. Payback Period calculated using real productive data (biogas yield) while running costs are hypothesized increasing of 20 percent values of electricity generation system.

e. Biomethane produced is sold to IOUs for 6$ per MM Btu.

f. All the dairies received same grants from the California Energy Commission as in precedent scenarios.

Analysis

Table 6.5.1 "Biomethane Upgradable in Scenario 5"

Dairy Name	Scenario 5 Biogas Yield (*5)	Actual Heat Content (MM Btu/mcf)	Scenario 5 Biomethane Upgraded in MM Btu/year	Scenario 2 Biomethane Upgraded in MM Btu/YEAR
Hilarides	131,400,000	0.523	68,722.20	44,417.64
Castelanelli	35,040,000	0.625	21,900.00	20,336.89
Koetsier	46,064,825	0.557	25,658.11	25,658.11
IEUA	173,688,900	0.648	112,550.41	26,771.46
Eden-Vale	32,179,860	0.552	17,763.28	17,763.28

(*5) assuming 60cf/cow/YEAR for those with actual low levels)

The comparisons between the assumption of biogas yield increased to 60 cf/cow/day and the actual real data denounce inefficiencies in collection processes of all the larger farms. 60 cubic feet of biogas per day is a quite standard yield that does not require any special operation technology upgrade or additional human management. Real yield values for Castelanelli, Koetsier and Eden-Vale were already very close or even higher than these rates, confirming the achievability of this result. Biomethane upgrading under conditions of scenario 5 can produce for all the candidates a sensitive improvement in terms of cash flow and consequent payback time compared with the previous upgrading scenario. This corroborates the conclusion that both electricity and biomethane base scenario were inefficient and can easily and inexpensively improve.

Table 6.5.2 "Costs for Biomethane Upgrading Technology part 1"

Dairy Name	Lagoon System	Scenario 5 Personal Investment	Scenario 5 Capital Cost
Hilarides	$366,268	$1,551,566	$1,917,834
Castelanelli	$311,044	$2,300,285	$2,611,329
Koetsier	$271,230	$1,714,247	$1,985,477
IEUA	$2,897,063	$1,967,524	$4,864,587
Eden-Vale	$438,433	$1,509,318	$1,947,751

Even in this scenario is evident how the distance from the NG pipeline represents an additional investment cost not associable with farm size, biogas produced or incentives received. Regardless of these variables and consequently of the amount of biomethane it will be able to produce, a farm will have to face this cost only due to its geographical position in respect to the NG network. The high impact of this voice of cost, confirmed by IOUs' specialists, can by itself reduce to zero the chances of a farm to produce biomethane economically.

Table 6.5.3 "Incentives and Maintenance Costs"

Dairy Name	Total Incentives	Scenario 5 Maintenance Cost per year
Hilarides	$500,000	$28,800
Castelanelli	$547,396	$14,400
Koetsier	$190,925	$32,400
IEUA	$948,175	$1,685,650
Eden-Vale	$300,000	$21,600

The Potential revenues are calculated from the potential biomethane yield assuming a value of $6 per MM Btu. The results of this assumption show how each farm would be able to create a solid cash flow system not only offsetting billing costs but producing and selling a product to a "customer", in this case the IOUs. Biomethane does not have restrictions to which the energy should be sold while electricity production agreement can only be signed with the IOUs operating in the area where the farm is situated. These restrictions clearly limit the demand and decrease the electricity market price and the contractual power of the producers.

Theoretically instead, biomethane upgraded in farm could be sold to any private or public body interested or obliged to purchase a certain amount of renewable energy (so far no biomethane in California has been sold at all).

Utilities, most likely, would propose as happened with Vintage farm in Fresno County, a ten years purchasing deal with a fix price for MM Btu to all the farms intentioned to produce biomethane. This however does not restrict producers to evaluate different solutions after this first period is ended, especially considering the fluctuation of natural gas prices in California. This option is a main advantage of biomethane installation that should be carefully considered.

Observing the single performance of each farm can be noted that Hilarides an IEUA gain the highest revenues in absolute terms and obtain good results even in terms of payback period.The high efficiency of the Hilarides system guarantee even in this case a return of the investment under four years reducing the values of biomethane scenario 4 of 30 percent.

Table 6.5.4 "Achievable Revenues Scenario 5"

Dairy Name	$/MM Btu of biomethane from IOUs	Revenues Scenario 5 from biomethane
Hilarides	$6.00	$412,333.20
Castelanelli	$6.00	$131,400.00
Koetsier	$6.00	$153,948.65
IEUA	$6.00	$675,302.44
Eden-Vale	$6.00	$106,579.70

The electricity scenario 3 though, where the same raw material inflows were assumed, resulted in a more robust investment even for Hilarides.

IEUA achieve an even more impressive result when compared with biomethane scenario 4 and electricity generation scenario 3, where the system showed very inefficient outcomes.

As for Hilarides however, also IEUA attained better results for the 60 cubic feet inflow scenario when the gas was used for power generation. Large energy users in fact gain a higher benefit from the energy bill offset and from selling the extra power for a value of 7cents/kWh if the demand charge, as in scenario 3, is not applied.

Only when the price of biomethane is estimated $7 for MM Btu then Hilarides and IEUA achieve a better result than in scenario 3.

Table 6.5.5 "Payback Time for Scenario 5"

Dairy Name	Scenario 5 Payback Time (year) with Incentives	Scenario 5 Payback Time (year) without Incentives
Hilarides	3.51	4.72
Castelanelli	15.82	19.98
Koetsier	11.87	13.11
IEUA	8.30	9.70
Eden-Vale	15.66	18.48

For what concerns with the other three smaller farms the results exclude the application of this technology with these productive numbers once these are weighed against scenario 3 ones. Power generation is in fact able to guarantee an efficient cash flow without requiring such large increase in personal investment that could be problematic for these family-size businesses regardless of the payback period obtainable.

Without wanting to assess a final conclusion, after studying four different scenarios (two of biomethane and two of electricity) we are able to affirm that Electricity generation requires in general smaller costs to deliver the "product' to the utility and is less dependent by the farm location. A more spread electricity grid can mostly explain this, together with the better development of technology that allows general cost reduction.

Biomethane upgrading on the other hand, does not appear as a very flexible technology and with more strict requirements but its future development can open many different selling solutions.

Findings:

- ***Biomethane Upgrading scenarios improve their feasibility when the biogas yield per cow per day is increased to 60 cubic feet per day.***
- ***Large productive realities are more likely to obtain positive result since economy of scale helps reducing costs of transportation and guarantee shorter investment return time.***
- ***Small dairies can find difficulties to finance these kinds of installations, especially if incentives do not at least cover 50 percent of the final cost.***
- ***Farm located farer than 1000 feet from the NG pipeline can consider this option only when their system produce at least 100 mil cubic feet of raw biogas annually.***
- ***$6 per MM Btu of upgraded biomethane does not result, with these assumptions, a sufficient price to encourage biomethane upgrading over electricity generation.***

6.6 Biomethane Upgrading Scenario 6

Assumptions:

a. Biomethane is obtained from the same digester system utilized for electricity generation

b. Biogas yield is assumed to be maximized to a level of 90 cf/cow/day, as proposed by PERI.

c. Upgrading Costs and Connection Costs have been increased of a percentage proportional to the increase in biogas yield but including a discount rate due to economy of scale.

d. Payback Period calculated using real productive data (biogas yield) while running costs are hypothesized increasing of each single scenario proportionally to the increase in biogas yield respect to precedent scenarios.

e. Biomethane produced is sold to IOUs for 7$ per MM Btu.

f. Same grants as per other scenarios have been considered.

Analysis

The results of the previous scenario showed that a value of $6 per MM Btu of biomethane and an increased biogas yield to 60 cubic feet/day/cow was not sufficient to support the installation of an upgrading system in the three small farms. The two largest ones (IEUA and Hilarides) achieved instead good results but inferior that electricity generation scenario 3.

For this reason we augmented the quantity of biogas gathered from each farm to a value of 90 cubic feet per day per cow. This value, PERI reported, was obtained at Meadowbrook Dairy one of the farms that we decided to not include in the analysis.

A value of $7/MM Btu has been considered in the calculations in case an additional environmental award

Table 6.6.1 "Biomethane Upgradable in Scenario 6"

Dairy Name	Scenario 6 Biogas Yield (*4)	Actual Heat Content (MM Btu/mcf)	Scenario 6 Biomethane Upgraded in MM Btu/year	Scenario 5 Upgraded in MM Btu/YEAR
Hilarides	197,100,000	0.523	103,083.30	44,417.64
Castelanelli	52,560,000	0.625	32,850.00	20,336.89
Koetsier	46,064,825	0.557	25,658.11	25,658.11
IEUA	260,533,350	0.648	168,825.61	26,771.46
Eden-Vale	32,179,860	0.552	17,763.28	17,763.28

These quantities of biomethane are hypothesized in order to evaluate the availability of this technology for larger system that could eventually consist in the collaboration of groups of farms collecting and producing biomethane collectively.

The costs of investment have been increased proportionally to the increased biogas yield. Economy of scale has been considered in large projects to calculate an estimated discount value.

With this Scenario 6 we try to evaluate a different kind biomethane production. A yield of 90 cubic feet daily in fact would require a complete involvement of the farmer economically and in terms of time, making this practice a large share of their business and not just a side activity.

Some companies, Vintage Farm is the first California example, are developing a system of integrated manure management able to handle these and larger biogas volumes. An integrated system is based on the collaboration of many farms producing manure that prefer a collective upgrading “station” to which all biogas is directed. One dairy installs a large upgrading system while other farms nearby digest their manure into biogas and deliver it to the main one. Large quantities of biogas can be produced and upgraded, reducing at the same time investment costs.

IEUA or Hilarides can be used in these terms to evaluate the feasibility of biomethane upgrading for these typologies of systems since they have a large herd. IEUA should be observed with special attention because in the real scenario this system is actually organized to receive manure from many farms. The final purpose for IEUA system creation was electricity generation, but it would be interesting to assess how the performances would change when this sort of organization was devoted to biomethane upgrading.

From an economical point of view IEUA would require a capital of $5,454,844 to create a system to the 90 cubic feet/day/cow inflow rate. The “collective” nature of the system though would allow dividing the cost through all the participating farms reducing the amount that each single would have to put down.

A single owner like Castelanelli instead should invest $3,071,386 by himself in order to be able to process this new amount of biogas and especially to transport it to the natural gas pipeline system. The values of Koestler and Eden-Vale are not increased compared with the scenario 5 because their biogas yield was already higher than 90 cubic feet/day/cow.

Castelanelli is penalized even in this case by the distance from the NG pipeline that requires an additional capital of $400,000 compared with the other farm of the same size.

These first considerations already indicate that for small family-based dairies could be risky to financially expose their business without a guaranteed better performance than in the other scenarios.Analyzing the revenues results in the table above, IEUA finally show a cash flow able to justify its large investment cost and to produce a better financial outcome confirmed by all the other projects.

Table 6.6.2 "Potential Revenues in Scenario 6"

Dairy Name	$/MM Btu of biomethane from IOUs	Scenario 6 Revenues Biomethane
Hilarides	$7.00	$721,583.10
Castelanelli	$7.00	$229,950.00
Koetsier	$7.00	$179,606.75
IEUA	$7.00	$1,181,779.28
Eden-Vale	$7.00	$124,342.98

Hilarides, the other large farm, obtains even more robust results achieving a payback time of 2.43 yr and 3.13 yr (no incentives). These indexes are not as positive for the three smaller dairies that despite an increased and steady biogas yield are not able to recover the large capitals invested in a time frame fewer than 10 yr.

The values for Castelanelli, Koetsier and Eden–Vale are only positive if compared with the scenarios 4 and 5 where biomethane was upgraded, but cannot compare with high efficiency on-site generation.

Table 6.63 "Payback Time for Scenario 6"

Dairy Name	Scenario 6 Payback Time (year) with Incentives	Scenario 6 Payback Time (year) without Incentives
Hilarides	2.43	3.13
Castelanelli	11.04	13.42
Koetsier	10.17	11.23
IEUA	5.24	6.04
Eden-Vale	13.43	15.84

Even in the best biomethane-upgrading scenario then, small size farms find difficult to achieve results able to justify a large investment like the one required by this alternative. Connection cost, purifying costs and especially transportation represent a complex barrier to this technology if the quantities produced are minute.

Findings:

- ***Biomethane upgrading option requires large investments and large biogas quantities to can create a stable economic system.***
- ***Small dairy farms found difficult in all the biomethane upgrading scenarios to create sustainable payback periods due to elevated investment costs.***
- ***Distance from the natural gas pipeline network can jeopardize the feasibility of a biomethane upgrading project regardless of the efficiency of how biogas is produced.***
- ***Large dairy farms or association of farmers producing together are more likely to obtain good results, but only when:***
    - ***Production is maximized***
    - ***The herd is compost by at least 6000 cows***
    - ***Large initial investment funds are available***
    -

6.7 Analysis Conclusions

6.7.1 Electricity Generation Scenarios Comparison

Table 6.7.1 "Comparison Electricity Scenarios"

Dairy Name	Base Scenario 1 (PEP=0) with INC	Base Scenario 1 (PEP=0) no INC	Scenario 2 Eff. 100% PEP= 7c/kWh with INC	Scenario 2 Eff. 100% PEP= 7c/kWh no INC	Scenario 3 (60cf/cow/day) PEP=7c/kWh with INC	Scenario 3 (60cf/cow/day) PEP=7c/kWh no INC
Hilarides	5.21	8.63	2.67	4.41	2.65	3.82
Castelanelli	10.59	27.31	5.20	13.36	4.77	11.08
Koetsier	48.50	56.23	8.73	10.12	6.54	7.22
IEUA	50.12	61.98	16.89	20.62	8.10	8.88
Eden-Vale	45.59	71.85	5.18	8.15	4.98	7.37
AVERAGES	32.00	45.20	7.74	11.33	5.41	7.68

PEP= Price for Extra Power, INC= Incentives

Eff.= Efficiency of the generator, PB= Price for Biomethane

The electricity comparison offers even more straightforward indications. The current practice adopted by farmers to produce on-site power is not a suitable solution in terms of green house gasses reduction or as a source of extra revenues for this sector.

None of the candidates with the only exception of Hilarides that managed to keep installation costs under $2500/kW could be able to see their investment covered within ten years. For three of them the payback period with incentives is expected higher than 50 years, resulting in a failure of the program. The solution of other issues, odor reduction and water quality improvement above all, that would have required anyways investments, made farmers quite satisfied with their systems despite the unsatisfactory economic achievements (reported by WURDCO 2006).

All the projects received consistent incentives for their equipment that were supposed to help producing energy in an environmental superior way. The levels of flaring reported for Scenario 1, and confirmed by the farmers, are incoherent with these intentions and make the evaluation on these projects even more negative.

In conclusion Scenario 1 appears financially to be a lost chance for farmers to create a side and independent source of income while environmentally did not achieved the results targeted in terms of emissions in atmosphere

Scenario 2 and scenario 3 instead propose a more efficient use of the biogas. In order to make this assumption realistic, it was necessary to modify the Net Metering Agreement and to assume a price for extra power produced and the absence of a demand charge. The difference in payback period is evident for all the farms advocating in favor of those that are requesting this sort of deal to be changed. Scenarios 2 and 3 indeed do not include the demand charge and the potential extra revenues are calculated and considered when the new payback periods are assessed. Scenario 3 in particular revealed that electricity generation can be an optimal application in California dairy farms once efficiency is guaranteed and a fair price for extra power is paid by the utilities. Small dairy farms find this application more fitting to the capitals they are able to invest, while scenario 3 represent a solid choice even for larger systems as soon as they on-site electricity demand is not too high. Scenario 3 proposed an increased to at least 60 cubic feet for all farms, but even in Scenario 2 where the only difference with the real scenario is the full efficiency of the generator and the use of the biogas usually flared, confirmed this positive trend both with or without incentives.

6.7.2 Biomethane Upgrading Scenario Confrontation

Biomethane upgrading systems appear in this analysis to be greatly dependent by the ability of the farms to formulate their process in the most efficient way possible. Biogas yield in particular represents the main reason of payback time shrinking in all cases studied in particular for those with a large herd.

IEUA system in the base scenario 4, where real values were used but no flaring took place, show that biomethane upgrading technology is not adapt to business that intend to develop this production as a side operation. High investment costs (on average 35 percent higher than for installing an electricity generator), elevated running costs and a complicate and expensive transportation logistics, made this productive alternative practically eligible only for large scale systems. Large farms like Hilarides or a “cooperative/association” of producers like IEUA are able to generate considerable quantities of biomethane. Biomethane do not allow farmers to make a large margin per MM Btu. The price is indeed defined in consequence of natural gas market price usually produced with lower costs in large scale by global companies. Southwest Natural Gas for example is able to set thanks to economies of scale during its process, a lower price and still able to gain higher net revenues for Btu than farmers.

Only producing large quantities a farmer would be able to create a robust system in terms of cash flow and or Investment Return Rate. Large size is not an assurance of success even in biomethane scenarios. IEUA in fact has demonstrated that without a solid project of manure collection, delivery and processing even system that on theoretically would have give surety of results, can fail (scenario 1).

For what concern with the price to be paid by the IOUs for each Btu of biomethane the discussion is complex. Seven dollars seem to be fair considering the environmental value biomethane brings. The supplementary benefit of the use in a combined cycle power plants should be awarded but market is the only element that can influence the price if the administration does not decide to intervene with a regulation.

The price of $6/MM Btu assumed for the first two scenarios was chosen following the discussion with utilities experts and it seems to be most likely what would be offered by PG&E to farms that decide to start this production. At this price the balance between the cases studied remain unchanged but with a predictable increase in all payback times.

6.7.3 Comparison "Without Incentives"

Table 6.7.3 "Comparison Productive Alternatives without Incentives"

Dairy Name	Scenario 1 Base case, (PEP=0) no INC	Scenario 2 Eff. 100% PEP= 7c/kWh no INC	Scenario 3 (60cf/cow/day) PEP=7c/kWh no INC	Scenario 4 PB=$6/MM Btu no INC	Scenario 5 (biogas 60cf/cow/day) PB=$6/MM Btu no INC	Scenario 6 (biogas 90cf/cow/day) PB=$7/MM Btu no INC
Hilarides	8.63	4.41	3.82	7.30	4.72	3.13
Castelanelli	27.31	13.36	11.08	21.52	19.98	13.42
Koetsier	56.23	10.12	7.22	13.11	13.11	11.23
IEUA	61.98	20.62	8.88	40.78	9.70	6.04
Eden-Vale	71.85	8.15	7.37	18.48	18.48	15.84
AVERAGES	45.20	11.33	7.68	20.24	13.20	9.93

PEP= Price for Extra Power, INC= Incentives

Eff= Efficiency of the generator, PB= Price for Biomethane

The absence of incentives is critical for many farms in many scenarios and this underlines a dangerous dependency of the technology from outside grants under the actual conditions of California market. The table above shows how Hilarides and IEUA achieved the overall best payback periods under scenario 6, demonstrating an effective stability of these projects. Those values (3.13 and 6.04 yrs) are not just positive in a niche technology application like this one but would be considered encouraging in any business development operation.

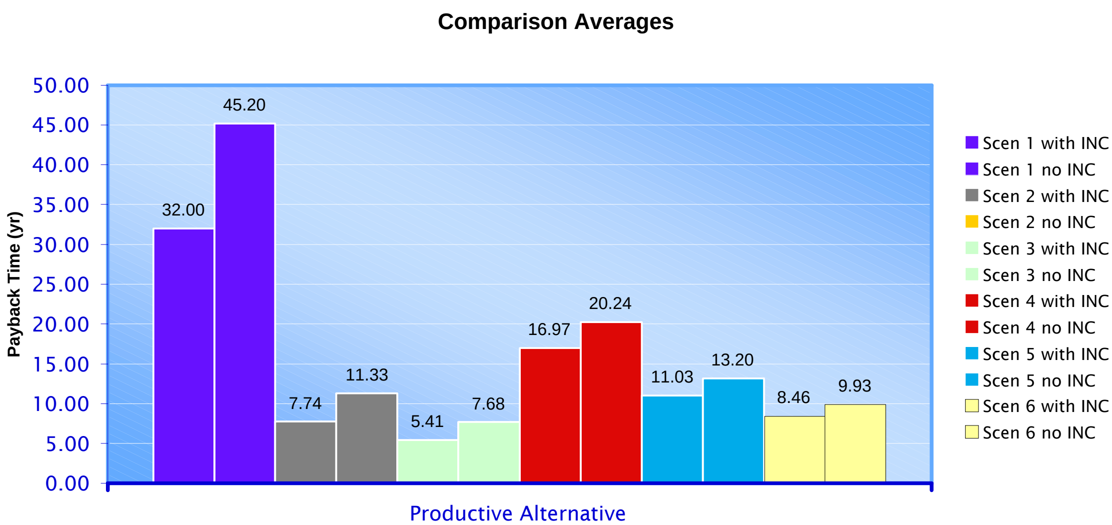
The analysis of the projects in the scenarios without incentives can give exceptionally strong indications on the real 'health' of the different options.

After a closer look on the table above, we are able to say that without incentives the electricity generation scenario 3 achieve good average values (7.68 yr) for the sector demonstrating that this option can reach good economic efficiency for a variety of farms with diverse characteristics. Small farms in particular seem able to create a solid financial balance especially compared with the biomethane scenario 6 where only big size dairy can put in place economy of scale.

Analyzing the results of the biomethane columns above, it is evident that small farms are not able to guarantee positive payback periods in any of the biomethane scenarios when incentives are not offered. The high dependency from this variable underlines the difficulties for family-size farms to consider biomethane a realistic option especially since the 1st January 2008 when Self Generation Incentive program do not include biogas project anymore

6.7.4 Analysis Headliners

Table 6.7.4 "Comparison of Average Values"



Average Comparison Tables can give to a policy maker a quick overview on the diverse alternatives. Through these values it is possible to identify the option that would bring the best benefit to the sector as a whole, and then define the policies necessary to support that scenario in the most efficient way.

Energy generation scenario 3 seems to be the productive solution capable to assure best results in average terms, when generator efficiency is maximized and a daily yield of at least 60 cubic feet of biogas per cow is guaranteed. Average values though could even be misleading because they offer a very specific snapshot of California situation using levelized indicators (average values in fact). The use of average values in fact can hide an important incongruity between large and small-scale dairies. Very distinct productive conditions and different issues to face, make these two kinds of farms almost poles apart in the realization of a biogas project. As a consequence of this, defining a unified policy from averages values could bring far from the optimal result for the sector.

For this diversity, a bidirectional policy to support power generation in farms under 2000 animals and biomethane upgrading in large dairies seem the best option for California.

Under the current typology of agreements between farmers and the IOUs (NEMBIO) none of the two productive options appeared to be financially stable for the producers.

The Scenario 1 and Scenario 4 showed that without an efficient use of biogas (no flaring) neither electricity generation nor biomethane upgrading would be able to guarantee an acceptable payback period.

Demand charge for electricity and high investment costs for upgrading reduce greatly the size of the possible cash flow, reducing the economic benefit of these systems.

The lessons learned indicate that a farm is more likely to success with the current available contracts for biogas-fueled electricity generators when the following conditions stay:

- On-site energy demand close to production rate
- Large direct on-site use of their power
- Low investment cost (use of refurbished materials)
- A biogas yield of at least 35 cubic feet per day per cow
- Maintenance cost lower than $4.00 per kW installed per year
- High system reliability (very rare periods in which the generator is down and on which demand charge is calculated)

The biomethane simulations showed that until NEMBIO conditions remain the same (no extra compensation) and assuming a value of $6/MM Btu, upgrading alternatives are more robust in comparison to on-site generation when:

- Farm has very little energy demand compared with the electricity could generate
- Farm has very high energy demand compared with the electricity could generate
- Farm can produce large quantities of biogas
- Farm has no real energy demand on-site

Biomethane upgrading though in order to represent a real option for farmers (not only superior in relative terms to electricity scenario) need:

- A herd of at least 6000 animals
- Can obtain at least 60 cubic feet a day per cow
- Is located within 1000 feet from Natural Gas network
- Price for biomethane of at least $6/MM Btu
- Produce a biogas with an actual heat content of at least 0.500 MMBTU per Mcf

If the Net Metering Regulation will be updated including compensation for extra power produced; electricity generation would be the best alternative for a Californian farmer with the following characteristics:

- At least 50-60 cubic feet of biogas cow can be gathered daily from each animal
- A herd smaller than 2000 animals
- Located farer that 1000 feet from a Natural Gas injection point

Chapter Seven: Discussion and Conclusions

7.1 Electricity Generation

California dairy farmers who decide to produce electricity with the biogas obtained from the manure digestion are going to face some complex market barriers.

In case the farmer decides to sell its power to the IOUs, electricity from biogas will have to compete with the electricity coming from all other fossil and renewable sources. While the IOUs have in fact accepted to purchase power from renewable sources in order to meet the California's Renewable Portfolio Standard (RPS), they have no requirements dictating on how this share has to be divided between the renewable sources. For this reason PG&E will purchase energy from biogas power plants only for a price equal or inferior to the market price. The main issue from a policy point of view is that California law states within the amendment of Senate Bill 463, that utilities may enter into a contract with eligible net-metered biogas generating facilities to purchase their excess electricity production. This Bill, however, just notifies the possibility to purchase this power at a price that cannot exceed the market price underling that such extra power will be accounted toward the Renewable Portfolio Standards required to each IOU.

California Public Utilities Commission is expected to decide on the AB 1969 within the end of February 2008. AB 1969 was a bill passed by the legislature in 2006 (it created a new law: Public Utilities Code 399.20). Decision (D.) 07-07-027 was a CPUC decision that voted out in July 2007 to implement the law and establish the CPUC policies related to the law. The resolution that was held (but had been scheduled to be on the CPUC agenda in January) can be found at www.cpuc.ca.gov and merely implements the July CPUC decision by adopting the actual tariff language. The bill was initially limited to water and waste water facilities. The CPUC implementation expanded the bill to any customer up to 1.5 MW for any renewable, and once the CPUC votes on it, there will be a feed-in tariff in California for all renewables up to 1.5 MW. Other metering program such as solar or wind provide producers full retail credit for investments related to generation, distribution and transmission, while no standby charge applies. The current tariff, on the other hand, credits biogas producers at a level equal to the generation level of their existing rate and only allows virtual aggregation of meters on the farm so they can compensate each other.

This second option has been proved economically inefficient for farm producers because of the gap between how they are charged for KWh produced and how much they are compensated for the KWh generated.

With an electricity cost of $0.053-$0.084/kWh depending on the time of usage and the net metering credits ranged from $0.022 - $0.036/kWh, plus an average of $0.04/kW for operation and maintenance costs for anaerobic digester and gas engines, the payback time period can be uneconomically stretched.

Furthermore, the analysis underlines how the low price paid by the utilities for kWh of excess power makes this production unprofitable and how a tariff more equal to the retail rate would ensure that all digesters were economical.

7.1.2 Electricity Productive Analysis

The largest revenue that a biogas digester can guarantee to a farmer willing to invest in the installation of this technology is the offset of the farm energy needs. At the moment of the realization of most of the digesters (2004) PG&E did not offer any sort of purchasing agreement to farmers willing to start producing electricity.

In all the cases however, electricity purchase represented one of the main voices of cost for the activity, especially for the milking parlor and the irrigation system used for the vineyard. In fact, under the scenario agreed between PG&E and four California farms, the power produced was not used on the farms or sold to the utility owner, but rather was exclusively accounted to obtain energy credits as defined in the Net Metering agreement. This allowed for a sensitive reduction in the amount of energy farms could purchase annually from the utility on which the payback period of the investment.

The energy sent to the utility is valued at the energy rate portion of the full retail rate and so it is charged per kWh consumed and varies by time of the day and season (demand-supply fluctuation of prices) without including the basic demand charge or customer charge. This point is particularly important when the profitability of a net metering system is evaluated. The demand charge is a consistent share of the total amount of a farm electric bill and the credits obtained cannot reduce how much the farmer has to pay for this charge.

For instance, many farms' electricity bills for instance, that are dated before the digester was installed, show that the 25% of the amounts were for demand charge.

Now, even though the generators produce an amount of energy 30% over the in-farm electricity need (this despite the fact that almost half of the biogas produced in the lagoon is still flared), the 25% is still intact in the electricity bill, representing now the 80% of the value. Many of the farms biogas producers have more than one meter connected to the generator and included in the NEMBIO agreement. The ones under PG&E are particularly charged, because the meters scan the electrical activity every 15 minutes (Edison and SoCal do it every 30 minutes) and calculate the demand charge for the month measuring the maximum kilowatt input recorded during this interval. So if for any reasons, maintenance or break down, the system is not producing power for longer than 15 minutes and the farm relies on the energy from the grid, the demand charge becomes equal to the one that normal customer (same energy demand but not producers of energy) have to pay.

This point has largely reduced the potential saving obtainable by farms in the actual productive scenario.

In particular many aspects of the agreement stipulated between the farmers and IOUs seem to be the main limitation to the profitability of these projects.

One of the best channels of economical support for the biogas-based electricity systems was provided by the Self-Generation Incentive Program was. Since the 1st of January, however, biogas has been listed in this program as a fossil fuel based technology and with the other fossil fuel based systems is not no longer eligible for incentives.

Renewable Energy Credits can represent a turning point in the overall economic assessment of biogas and electricity production. All the deals signed by PG&E, for instance, until the current date gave the ownership of the certificates to the utility owner, denying biogas producers from any environmental credit.

Furthermore, the current tariff structure is particularly discouraging for dairy farms that pay a flexible rate to purchase energy coinciding with the different time of the day, while receiving credit at a fixed rate.

7.1.3 Electricity Conclusions

The main elements that are currently reducing the development of electricity production from biogas:

a. Net Metering Terms for extra power purchasing. The lack compensation for extra power produced has pushed farmers to size their digesters and generators strictly to their internal demand even if they produce a larger quantity of manure.

b. The end of SGP eligibility for biogas plant since the 1st of January 2008 could jeopardize the profitability of these projects.

c. Lack of economic support toward interconnection metering system and other expenses has increased the payback period for the investments the farmers have to face.

d. The Renewable Energy Credits ownership could represent an additional source of revenue for the farmers to repay their investment, but at the moment are taken by the utilities without any extra compensation.

e. The cap (50 MW) of maximum installed power that can apply for the grants of the Self Generation Incentives Program to be a measure in contrast with the State Bioenergy Action Plan.

In conclusion, it appears evident that with the current wage paid for kWh by PG&E and in order to make profit, dairy farms must:

- *Use on-site at least 75 percent of the energy they produce*
- *Use for productive purposes at least 50 percent of the heat produced*
- *Not send energy to the grid*

7.2 Biomethane Upgrading

The main issue for the realization of a biomethane production system is the absence of a clear and unified white paper where the applicable regulations, quality standards and regulatory requirements are listed.

Often the most difficult passage is to understand which rules apply and which agencies (state, federal, local) are in charge for those rules. This provokes a remarkable delay in the installation time due to bureaucratic issues.

Quality Standards for pipeline injection defined by PG&E require an advanced upgrading system. This technology needs a quite expensive investment that together with transportation cost has represented so far the major barrier to biomethane development in California.

Biomethane transportation can be engineered with a dedicated pipeline system or with a connection system to the natural gas pipeline. The first option has proved to be practical only when the production point is very close to the injection point requiring a high investment per mile that very few dairy farmers can realistically afford. The cost of transportation has to be considered when the selling price is defined. Biomethane will have to compete with conventional natural gas and so any additional cost could put biomethane off the market. PG&E refused to write off the additional cost of biomethane on all the natural gas consumers and from a consumer point of view this policy can be understood.

Furthermore, A Market Price Referent is necessary for a real development of this application. Farmers need to know the precise price at which they will be able to sell the product, plan their economic activity and evaluate the kind of mortgage this will require.

Considering only the base scenarios 1 and 4 where Electricity Generation and Biomethane Upgrading are compared under actual productive conditions, biomethane can guarantee to the farmers a better deal with the IOUs compared with the electricity generation option.

Indeed if the farmer is able to overcome the first economic issues and produce an amount of biomethane sufficient to justify transmission and injection costs, biomethane will allow the farmer to maximize their biogas production. As showed by Hagen [56], in fact the main limit in the Net Energy Metering deal signed by farmers that produce in-farm electricity is the lack of compensation for extra power produced. As a consequence in many cases (Castelanelli being one of those) the farmers flare a great share of the biogas produced once the energy credits obtained compensate their electricity bill.

If biomethane is purchased as a normal product $/Btu, the farmer will try to obtain the greatest revenue possible from the system having theoretically no boundaries on how much they can produce.

7.2.2 Environmental Outlook

WURDCO reported impressive rates of biogas flared in the base scenario 1. The environmental impact of this procedure is easily deducible and it appears incoherent with the overall purpose of this program, primarily financed by the California Energy Commission and by the IOUs to increase the share of renewables in the State. In addition, the recent progresses achieved in the International Meeting on Global Warming in Bali 2007, and a partial commitment from U.S. administration could result in stricter regulations concerning air quality. Fossil fuels, including natural gas, could face an increase in prices consequent the introduction of carbon taxes, which would make biomethane a more economical solution.

The issue of the so called "Environmental Award" to be added to the valued paid by the IOUs to farmers, both for electricity and biomethane, could favor both these technologies. The California Energy Commission is in fact evaluating the possibility to add a $20/MWh "environmental adder" to support the farmers. No Federal Bill has yet to propose this new deal so it has not been considered in the calculation sheets.

7.2.3 Socio-political Outlook

The Energy Commission report underlined how dependent California is from Southwest and Canada natural gas and how heavily this affects the ability to reduce GHG emissions and to plan energy policies. Biomethane could even in a small part represent an alternative, reducing this reliance, and to create specialized jobs in the state. Both options as demonstrated in this report however, necessitate an encouragement by the Federal and State administrations.

7.2.4 Conclusions

a. Biomethane upgrading is a well-known and pretty widely applied technology in Europe especially in Denmark and Sweden. In California, as well as in the entire U.S., this application is very recent and only one project is currently developing upgrading equipment.

Only from July 2007 when California Public Utilities Commission (CA PUC) has approved an agreement for the Vintage Dairy Farm (under engineering patronage of BioEnergy Solutions) to supply up to 3 billion cubic feet of methane extracted from cow manure to Pacific Gas & Electric Company (PG&E). Vintage Dairy, located in

Fresno County, California will flush the manure from its and other farms into covered lagoons that will trap the methane gas produced as the manure decomposes and will purify it into an upgrading system.
If Vintage Farm-BioEnergy will obtain positive results especially from an economic point of view, we expect a spread of digester facilities and pressurization equipment in other dairies of the region to site additional.

b. Biomethane Market Price

The absence of a biomethane market reference price is the first financial obstacle to the development of biomethane production California. IOUs in fact will purchase Biomethane at the same price they pay natural gas, while farmers will have to cope with high transmission and injection cost reducing their margins.
For this reason it is complicated to produce a business plan for a biomethane farm being the price of the product not officially standardized. In order to develop our analysis we estimated it through of natural gas price that is at the moment only referent and the value can be found above in this chapter. Common forecasting [46], however, confirms that if natural gas continues its increasing trend, this will help biomethane to become more competitive, supporting a further spread of the practice.

c. Transportation and Injection cost

Financially small-scale biomethane applications are hard to realize because of the high cost to deliver the gas from the producers to the customers.
A dedicated pipeline to connect the farm to the Natural Gas pipeline represents a very costly solution as showed by the case studies above. This option is applicable when the farm is producing large amounts of biomethane to recover the cost [13] or when many dairy farms producing biomethane are operating in close proximity. This second solution under study by the IOUs would require lower investment cost for actual Btu produced and will reduce the maintenance cost largely.
Eventual environmental drawbacks can be represented by the emissions released during the transportation of the manure from each dairy farm to the biomethane plant.

Chapter Eight: Recommendation for Improvements and Future Studies

8.1 Public Policy Improvements Necessary

The use of anaerobic digestion in dairy farms can guarantee a consistent reduction in methane release, bad odors and water pollution. Large quantities of manure are produced daily in the many California dairy farms, and this resource is precious and cannot be wasted principally in consideration of GHG reduction goals defined by Governor Schwarzenegger.

Many regulatory papers have been approved to support the diffusion of renewable energy. General legislation aimed to define air quality standards, others delineating renewable share requirements for Investor Utilities Owners and others offering funds to sustain the installation of CO2 free energy systems. California's Renewable Energy Portfolio Standard for example is a clear act of support from the California administration in this sense. With this policy indeed California state required IOUs to achieve a 20 percent share of renewable in the energy they sell in California within 2010.

The current state of the regulations though does not, in reality, allow such an expansion due to some fundamental contractual and legal restrictions for both the technologies:

Biomethane:

Biogas Price

This study has assumed, after discussing with sector specialists, a possible price for upgraded biomethane to a value of 6 dollars per MM Btu, modifying it in the last scenario to 7 dollars per MM Btu. The necessity of assuming this price was due to the lack of a market price for this product. Such elevated uncertainty in the financial planning of a project is reducing the number of farmers that could be interested in this production.

Electricity:

NEMBIO, Net Energy Metering Credit from Biogas is not an adequate tool to stimulate the use of biogas on-site generation in California dairies. Only under very specific productive conditions, not applicable for most of the farms located in the state, a on-site generation system can produce good economical performance. In particular, elements that are jeopardizing the diffusion of biogas electricity generation are:

- *Lack of credit for the energy produced over the demand rate.* This was the cause of the failure of four out of five cases studied and can discourage other candidates from considering this option.
- *Self Generation Incentives Program.* This program was the main source of funds for all the dairies considered in this study. Since the 1st of January 2008, biogas project are not eligible anymore for SGIP grants that are offered exclusively to wind, fuel cells or solar technologies.
- *Reduction of Incentives.* The reduction of incentives could definitely eradicate the margins of improvement for this typology of installations. This study showed indeed when efficiency is guaranteed; incentives are not vital to obtain a positive payback period. However high investment costs, without any sort of grants, could reduce the number of farms able to invest autonomously these large sums in the development of this equipment.
- *Renewable Energy Credits.* Currently renewable Energy Credits are automatically obtained by the Utilities once the power is purchased. REC are mainly the reason for which IOUs decided to acquire energy from farmers. These credits can help them to reach the 20 percent target by 2010, but no additional value is aggregated to the price paid for kWh by the IOUs.
- *Demand Charge and Tariff Structure* Many projects have been penalized by the low off-peak energy costs and by the high non-coincident demand charge that largely reduces the revenues obtainable from the energy generation.

Furthermore, considering all the costs of interconnections and the fees that are still charged on a producer, the final income that the farmers can obtain per kWh is too low to guarantee a feasible return time for the investment and much lower than how much is charged to them for the energy consumed.

This report has underlined first of all the necessity of a firm and resolute action from California administration and California Public Utilities Commission.

California has the resources, the technology and the capitals to invest in both electricity generation and biomethane upgrading, but the current status of the regulations do not allow any of these options to be economically feasible.

8.2 Future Research Needed

Electricity

The study of the on-site generation is particularly interesting in terms of defining the perfect tariff for extra power generated with or without demand charge. This project would require the calculation of the levelized costs of electricity of each scenario, and to find a way to reduce investment costs.

Biomethane

The connection between biomethane upgrading and multi-farm solutions is particularly relevant. The first actual case of biomethane upgrading is in last phases of its installation and the analysis of this productive case could be fundamental to understand in which direction public policy should be directed. Conglomeration even in this case seems to be a good solution in terms of maximization of profits and cut down initial costs.

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