Small Farm Manure-Based Anaerobic Digestion Systems and Barriers to Increasing their Implementation in New York State

Wagner Farm's (Poestenkill, NY) anaerobic digester for 350 cows.

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Small Farm Anaerobic Digestion Systems and Barriers to Increasing their Implementation in New York State

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Executive Summary

United States Secretary of Agriculture Tom Vilsack has stated a goal of one new manure-based anaerobic digestion (AD) system brought online in the U.S. per week, but there are some real challenges that need to be overcome to make this goal a reality. Efforts have primarily focused on large dairy operations where economies of scale and other factors make investing in AD systems less risky to the overall viability of a dairy business; however, the majority of dairy farms in New York State and the U.S. are small in nature. Therefore, the United States Department of Agriculture (USDA) and the New York State Energy Research and Development Authority (NYSERDA) would like to understand what may be needed to result in an increase in the number of small farms implementing AD systems, and therefore have commissioned this report to identify the barriers to adoption.

The document is broken down into two parts. Part 1 provides background information and a more general discussion of the technical, economic, and regulatory issues and hurdles relevant to small farm anaerobic digestion. This section is non-quantitative in nature. Part 2 focuses on the implications of different cost and benefit scenarios on the economic viability of small farm digesters. Economic viability is key to successful long-term operation of AD projects, and this is why the paper focuses so closely on it.

Part 1 - Technical, Economic and Regulatory Hurdles to Small Farm Anaerobic Digestion Implementation

One of the greatest hurdles to small farm AD implementation is the fact that AD projects benefit from economies of scale. Generally, as the project size increases, the per cow cost of the project decreases. Additionally, larger projects can potentially hire personnel to manage digester and engine-generator operations; a critical consideration if co-digestion is pursued with high levels of additional off-farm organic material. Increasing herd size to increase manure and biogas production, may not be an option for a farm depending on the land base available. Increasing biogas production through the use of co-digestion may also be limited by the nutrients contained in the imported substrates, which need to be accounted for by the farm's Comprehensive Nutrient Management Plan (CNMP), if they are required to have one.

Efficient AD requires the addition of manure/feedstock on a regular (daily) basis as starting and stopping reactors seasonally is not a feasible option. Cattle management systems where manure is only seasonally collected, such as pasturing, are thus not well suited for anaerobic digestion. Ideally a system will have an influent tank that is used in part to balance the loading of the reactor. Manure storage facilities are often used to store the effluent from an AD. Existing long-term manure storages are required pre-AD project for a farm to be able to qualify for carbon credit sales; however, many small farms lack long-term manure storage.

Farm location can also impact the feasibility of AD projects. If co-digestion is expected, a ready and reliable source of biomass is required, the closer the better. If power sales are planned, proximity to three phase power lines is usually necessary.

Technically, AD systems are very scalable and can and have been designed and implemented on small farms. However, the long-term reliability of small systems is generally unknown because there are so few small-scale projects.

One option that small farms may possibly take advantage of is modular/portable systems that can be constructed off-site and relocated as needed. Larger, constructed in-place digester vessels suffer from high lost capital costs and if a project fails little value can be recovered. Small moveable AD systems can possibly be treated like any other piece of farm machinery making financing potentially easier to obtain.

Power generation from biogas is difficult with small farms, as there are few engine-generators of a suitable size. The smallest commercially made, biogas-specific engine-generator known to be currently available in the U.S. is the IPOWER Energy Systems ENI 20- kW. Modified engines with smaller capacities have been used, but have proven unreliable when used with raw biogas. Biogas cleanup (predominantly H_2S reduction) before use in an engine involves additional expense, whereas using biogas directly in an engine-generator can greatly shorten its useful life.

Preventative maintenance of the digester and engine-generator is critical to reducing unscheduled shutdown time. Small farms with fewer personnel may find it difficult to allocate the necessary time for general maintenance and especially when a maintenance item or repair requires a larger time period of work.

In terms of economics, generally the lack of existing manure storage and liquid manure handling equipment on small farms increases the overall capital cost of installing AD systems on these farms.

There are also many fixed costs associated with digester projects that must be paid regardless of project size, such as design and engineering, permits, and utility interconnection fees. As a percentage of total system cost they are much more significant for small farm owners. Beyond the cost of applying for permits and/or energy audits, the time required to dedicate to the project through design, grant application and construction may be more difficult for a small farmer with fewer staff available to assist.

AD systems are capital intensive and require financing. The inability to attract financing is a key barrier to the widespread adoption of AD systems (Gloy and Dressler, 2010). Uncertainty about the rate of return, the economic value of the benefits, the reliability of the system, and high lost capital costs make securing financing arguably the most difficult step of implementing an AD system. When there is a positive rate of return, the relatively low value for an AD project may not compete with the rate of return of other investments a farm may make.

Revenue from co-digestion is also a potential means of improving the financial viability of a digester project, primarily through the collection of tipping fees and sometimes but to a lesser extent, through increased biogas yields. However securing long-term contracts to guarantee the availability and revenue from imported substrates is not common.

Smaller projects have a harder time proving viability, particularly as there are so few examples of successful operations.

The current net metering laws in NYS discourage small farms from producing more power than they can use, as any net surplus electricity (determined on a yearly basis) is paid to the farmer at the utilities' avoided cost rate (typically less than $0.05 per kWh). This is in contrast to some other states that have feed-in tariff (FIT) systems that pay a premium for renewable energy. The NYS net metering law also limits co-digestion to no more than 50 percent (by weight of the total digester influent) of food waste to be co-digested with manure.

New York's solid waste regulations (NY 360) may pose a problem for some small farms co-digesting food wastes. Ordinarily, co-digestion of food wastes are regulated through a farm's concentrated animal feeding operation (CAFO) permit. However, in NY, farms smaller than 200 cows are not usually required to obtain a CAFO permit and so would require a NY 360 permit for co-digestion.

The generation of electricity and heat from biogas does have implications for air quality. Engines usually must be adjusted in the field due to variability in biogas quality and so emissions testing must also be done in the field with prices ranging from $5,000 to $10,000. For engines between 100 and 500 hp, a test at the time of installation is required, however, in addition, larger engines (>500 hp) need to be tested every year.

A major reason for installing a digester can be the reduction of farm odor emissions, to reduce complaints from neighbors. Smaller farms may not have as much of a perceived odor problem as larger farms. Digesters can improve water quality through reducing oxygen demand and pathogen load of the effluent, and nutrient losses through increased flexibility in field application of effluent. However it is difficult to place an economic value on these, to assist in justifying the expense of a digester.

Part 2 - Economic Analysis of Small Farm Anaerobic Digestion

To compare the effects of different benefits pricing, electricity sales method, and costs, have on the economic feasibility of small farm AD, cost-benefit economic analyses were used. In the cost-benefit analyses, the benefits and costs are expressed on an annualized basis, and the costs are subtracted from the benefits to determine the overall annual economic impact of the system. For this analysis, positive values indicated that the project may be economically feasible while negative values indicated that providing for odor control and other non-monetary benefits would be a cost to the farm.

To investigate the impact of different benefit pricing, capital cost, and power sale method on small farm AD economic feasibility, a mathematical model of small farm AD was developed. The small farm AD model uses farm size as an input, and with other parameters such as co-digestion ratio, predicts the likely system parameters such as biogas and electricity production, engine-generator and digester vessel size and volume of co-digested material. Coupled with farm energy audit data specifically from small NY farms, surplus energy available for sale was predicted.

The developed small farm AD system model was then used to perform a series of cost/benefit analyses for five different base scenarios as follows.

1. The effect of benefits pricing and fixed capital costs with a net metering approach to power sales (as is currently used in NY State).
2. The effect of benefits pricing and capital cost (same as in scenario 1) with a feed-in tariff approach to power sales.
3. The effect of benefits pricing and capital cost with net metering power sales (same as scenario 1), but that also includes additional cost for long-term manure storage.
4. The values of benefits pricing necessary to offset costs with a fixed farm size.

5. The farm size needed to produce enough biogas to operate the smallest commercially available biogas fueled engine-generator.

The variables investigated included the sale price of surplus generated electricity, carbon credit pricing, co-digestion ratio, tipping fee price (money collected by the farm for disposing of organic wastes with co-digestion) and project capital cost. Electricity sale prices of $0.05, $0.16 and $0.31 per kWh were investigated with $0.05 approximating the current avoided cost rate paid by a NYS utility to the farms under net metering. Sale prices of $0.16 represent power prices projects in Vermont recently received and $0.31 per kWh represents a high value that is unlikely to be seen in the U.S. in the near future, but have been paid in Europe. Carbon credit prices of $10 per metric ton represent the high values seen on the Chicago Climate Exchange (CCX) before it closed, and $20 represents a high value that might be realized if carbon credit trading is implemented by Congress. Co-digestion ratios (manure:non-manure) of 75:25 and 90:10 on a volatile solids (VS) basis, represent a high and a moderate level of co-digestion that should be easily manageable by a small farm. Higher levels of co-digestion are possible, however as the ratio of co-digestion increases, the difficulties in maintaining stable digester operations also increase. Net tipping fees (what the farmer collects minus their added cost of spreading additional liquid) of $0.05 per gallon for whey represent a typical value paid to farmers. $0.10 per gallon represents more of a premium (but potentially achievable) price for disposal.

In the first two scenarios, combinations of the values of the variables discussed above (surplus power sale price, $0.05, $0.16 and $0.31 per kWh, net tipping fee, $0.05 and $0.10 per gallon, co-digestion ratio, 0, 10 and 25% VS basis, and carbon credit value, 0, $10 and $20 per metric ton) were used with two fixed capital costs ($3,000 and $1,500 per cow). In the third scenario the same combinations and values were used, but carbon credits were not considered. In the fourth scenario, a fixed capital cost of $2,700 per cow (representing a typical capital cost for a small farm of 153 milking cows) was set and the various benefits were investigated for what values are necessary for a neutral cost-benefit. The fifth and final scenario did not consider economics, rather the size of farm necessary to fuel the smallest commercially available engine-generator.

In the **first scenario**, the effects of benefits pricing and capital cost were evaluated with a net metering approach to electricity sales (current NY state model). The analyses found that with a project capital cost of $3,000 per cow, only 10 combinations of benefit pricing out of 63 analyzed resulted in a neutral or positive annual cost/benefit. The combinations that had a positive or neutral benefit were those that had a maximum co-digestion ratio 75:25 manure:whey and maximum net tipping fee ($0.10 per gallon). With a project capital cost of $1,500 per cow 34 scenarios out of 63 resulted in a neutral or positive cost/benefit, however all of them had some level of co-digestion 90:10, or 75:25 manure:whey (VS basis). In these analyses no long-term digester effluent storage or spreading costs were considered, and had they been considered, the outcome of the analyses would be that significantly fewer combinations would have resulted in a neutral or positive cost/benefit.

In the **second scenario,** the same analyses were run with the same combinations of variable values as in the first scenario, though with a feed-in tariff approach to electricity sales rather than net metering. At a capital cost of $3,000 per cow, 13 out of 42 combinations were potentially viable, however co-digestion with a tipping fee was still a requirement for a neutral or positive cost/benefit. At a capital cost of $1,500 per cow, the highest value of feed-in tariff ($0.31 per kWh) did not require co-digestion and overall 31 out of 42 combinations were potentially viable. However it is unlikely on-farm anaerobic digestion systems for small farms with biogas to energy conversion will cost $1,500/cow or less, and similarly to the first scenario, had the cost of storing digester effluent long-term been included, the number of combinations resulting in a neutral or positive economic benefit would be fewer.

In the **third scenario**, the annualized capital cost of long-term manure storage based on farm size (effluent volume) was included (as an additional cost on top of the $3,000 or $1,500 per cow capital costs) with net metering. At $3,000 per cow only two combinations out of 21 analyzed were potentially viable; those with maximum co-digestion ratio and tipping fee and a surplus power price of $0.16 or $0.31 per kWh. At $1,500 per cow capital cost eight combinations out of 21 were potentially viable. All required co-digestion. Surplus power price did not factor into the results of these combinations as at the farm size where the cost/benefit was potentially viable, the farm was not producing enough electricity to meet all of its demand (and so no power was sold).

In the **fourth scenario** a fixed farm size (the U.S. average herd size of 207 LCE_{VS} or 153 milking cows) was used. Capital costs were fixed at $2,700 per cow (except where capital cost was the variable being analyzed). The analyses found that with a farm this size:

- Using no co-digestion (or carbon credits) a surplus power price of $4.66 per kWh was necessary for a neutral cost/benefit.
- With maximum analyzed co-digestion (75:25) and highest reasonable net tipping fee ($0.10 per gallon) surplus power sales were not necessary for a neutral cost/benefit.
- With maximum analyzed co-digestion (75:25) a net tipping fee of $0.08 to $0.06 per gallon was necessary for a neutral cost/benefit with net-metering at the avoided cost rate of $0.05 per kWh.
- With intermediate co-digestion (90:10) a net tipping fee of $0.21 to $0.18 per gallon was necessary for a neutral cost/benefit.
- With no co-digestion (or carbon credits) and a net metering surplus power sale price of $0.05 per kWh, the per cow capital cost of the system would need to be less than $561.28 for a neutral cost/benefit.
- With maximum analyzed co-digestion (75:25) and net tipping fee ($0.10 per gallon), the per cow capital cost at which the system is potentially viable is $3,722 or less (i.e. if the actual capital cost is less than this value the project should be potentially viable) if surplus power is sold for $0.31 per kWh or less than $3,122 if surplus power is sold for $0.05 kWh.
- With intermediate values of co-digestion (90:10) and net tipping fee ($0.05 per gallon), and a per cow capital cost of $2,700 (including additional long-term storage costs), a grant covering 50% of the capital cost ($1,350 per cow) would result in a neutral cost/benefit.

In the **fifth scenario** the small farm AD model was used to determine that for a 20-kW engine-generator with only manure as the feedstock, it would take a herd of 118 milking cows to supply enough biogas to operate the engine-generator at full capacity. Manure and whey digested on a 75:25 VS basis, corresponds to 95 milking cows and 90:10 VS basis, to 108 milking cows.

Overall, the clear finding of the cost/benefit economic analysis is that co-digestion is key to improving the economic viability of digesters, primarily through collected tipping fees, and in some cases through increased biogas production.

Under the current net metering laws in NY state, surplus electricity sales do not significantly help the economic feasibility of small farm anaerobic digester projects, even when premiums for surplus power (above the avoided cost rate) are paid. A feed-in tariff method of power sales is more beneficial, but not to the extent tipping fees from co-digestion are.

Overview

The United States Department of Agriculture (USDA) and the New York State Energy Research and Development Authority (NYSERDA) have committed to increasing the adoption of anaerobic digestion on dairy farms in NY state (and nationally for the case of USDA). While past efforts have generally focused on large dairies, USDA and NYSERDA would like to extend adoption of anaerobic digestion to small farms as well. However, to do so, the barriers facing small farm adoption first need to be identified.

The purpose of this document is to present the reader with background information about small dairy farms, anaerobic digestion, some of the technical, financial and legislative considerations affecting small farm anaerobic digestion (AD), and finally to present economic analyses of the effects of different cost and benefit scenarios on the economic viability of small farm digester projects.

It is assumed that the reader has a knowledge of anaerobic digestion and dairy production. For more background material on this subject the authors recommend reading the Dairy Waste Anaerobic Digestion Handbook: Options for Recovering Beneficial Products From Dairy Manure (Burke, 2001).

This paper has several goals depending on what aspect the reader is interested in. For the small farmer considering an AD system, a general background is provided, detailing some of the challenges that need to be overcome in developing a project, with a particular focus on economic viability. For government officials, an overview of the aspects hindering the adoption of AD on small farms is provided along with information about how changing policy could affect the economic viability of projects.

The document is broken down into two parts. Part 1 provides background information and a more general discussion of the technical, economic, and regulatory issues and hurdles relevant to small farm anaerobic digestion. This section is non-quantitative in nature. Part 2 focuses on the implications of different cost and benefit scenarios on the economic viability of small farm digesters. Economic viability is key to successful long-term operation of AD projects and this is why the paper focuses so closely on it. The results are general in nature so as to be applicable to a wider range of farm scenarios.

The document primarily focuses on NY state, however the information and analyses are relevant beyond the Northeast to include the Midwest and parts of Canada.

Part 1 - Technical, Economic and Regulatory Hurdles to Small Farm Anaerobic Digestion Implementation.

1.0 Introduction

1.1 Summary of small farms in the United States and New York State

In the United States, approximately 88% of dairy operations consist of farms with fewer than 200 head, and overall the average number of lactating cows per operation is 153 (USDA, 2010). The largest dairy producing state is California with approximately 1.77 million cows in April of 2011. The next largest is Wisconsin with 1.27 million cows, followed by New York with 610 thousand, Idaho with 576 thousand, and Pennsylvania with 543 thousand (USDA, 2011). In New York State, in 2007, there were an average of 627,000 cows on 5,683 farms, for an average of 110 cows per farm (NY State Department of Agriculture and Markets, 2009).

The dairy industry is very low margin and with milk prices that are very cyclical in nature and hard to predict, farms depend on good years to carry them through periods with low prices. Though also cyclical, on average, production costs are also increasing. Feed represents 78% of the cost of milk production (Figure 1); therefore, any increase in feed prices translates to a major cost for farmers. Increases in the cost of diesel have further negatively affected the bottom line of dairy farms.

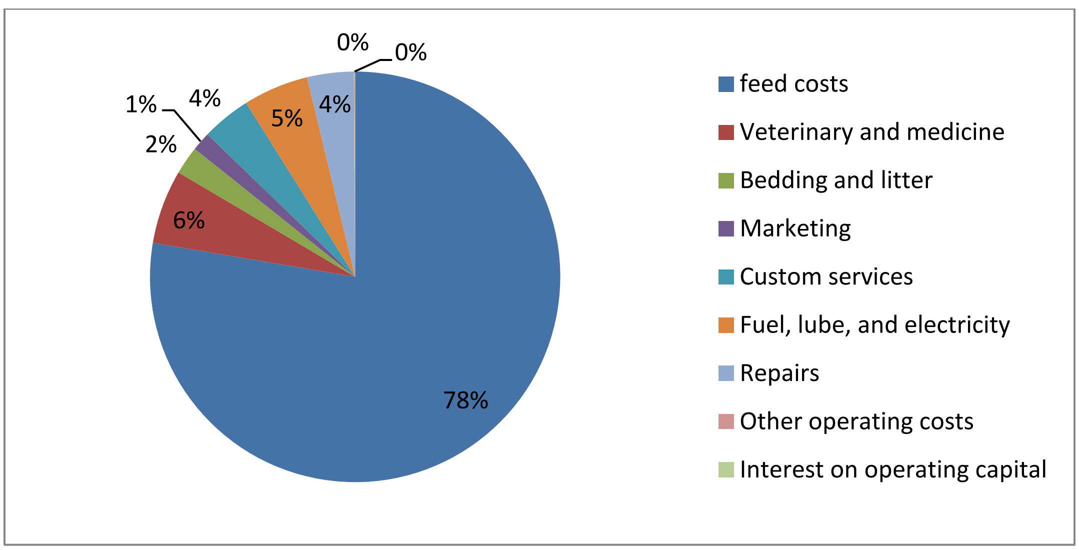

Figure 1. Cost of milk production for May 2011 (USDA, 2011)

Figure 2 is a plot of the average size of U.S. dairy farm, and the total number of farms from 1970 through to 2011. It is clear from the plot that farm sizes are increasing, while the number of farms is decreasing.

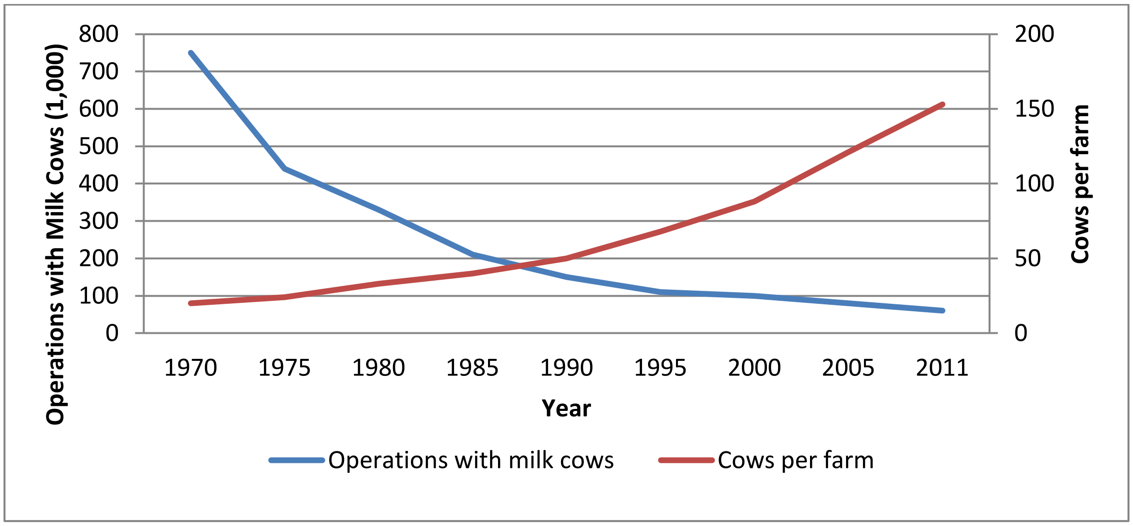

Figure 2. The Number and Average size of U.S. Dairy Farms 1970 to 2011 (USDA, 2010)

The term "small farm" is quite subjective, and what it means will vary considerably depending on how it is defined. The USDA defines farm size by the gross sales volume (USDA, 2002). Under this definition small farms have sales of between $50,000 to $250,000 per year. On average, farms with 100 cows have a gross income within this range. Very small farms have below $50,000 per year in gross sales and they correspond to farms with an average of 26 cows.

The 2011 average U.S. herd size of 153 cows corresponds to the upper range of the USDA income definition for small farm. So a majority of the current dairy farms in the U.S. are in the small farm category as defined by the USDA.

The USEPA-AgSTAR program maintains a database of anaerobic digestion projects in the U.S. (AgSTAR, 2012). According to this database there are approximately 158 on-farm anaerobic digestion projects that are currently operational (Figure 3). Of the 158 projects, 14 are classified as covered manure storages that do not optimize the production of methane as more conventional digesters are designed to. Of the balance of 144 projects (of which a further 10 are no longer operational or miscategorized), only 2 are for farms that are less than 200 cows, and only 13 for farms less than 400. The average operational digester is approximately 1,800 cows.

AgSTAR does not recommend AD for farms less than 500 cows because of the investment required, and this can be clearly seen in the lack of projects below this size (AgSTAR, 2009).

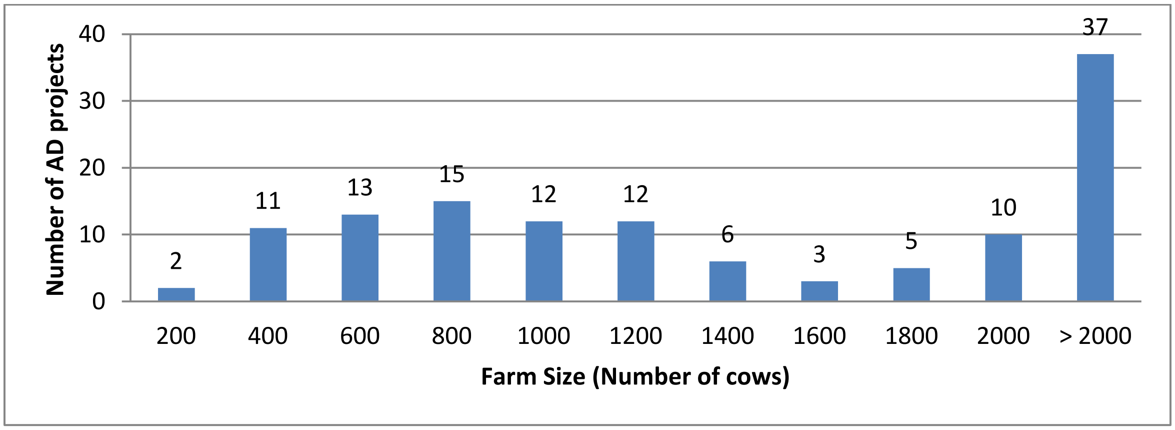

Figure 3. Number of operational U.S. Dairy AD projects with Cogeneration by farm size (AgSTAR, 2012)

While digesters represent a very significant investment for a dairy operation, the potential benefits they provide can be very important to farm operations.

1.2 Benefits of anaerobic digestion

There are a number of benefits associated with anaerobic digestion (AD) systems.

With the encroachment of residential development in rural areas, requisite odor control is a very real benefit of anaerobic digestion. Odor complaints from neighbors can be significant problems, especially for larger farms. Anaerobic digestion reduces the volatile fatty acids which (when broken down by bacteria) are primarily responsible for odor generation, making the resultant digestate easier to store and spread under more conditions than untreated manure. The flexibility in field application of an odor reduced effluent from AD allows a farmer to recycle manure nutrients as organic fertilizer at the most opportune times, reducing nutrient loses to ground and surface water and improving crop yield. The temperatures used in AD also lead to the significant destruction of pathogens such as fecal coliforms; organisms associated with contaminated drinking water.

AD provides the potential to generate electricity and/or heat from combusting biogas produced from a digester. Biogas can be directly burned in a boiler to provide hot water to maintain the temperature in the digester and for other on farm uses such as heating wash water. Biogas can also be used to fuel an engine-generator to generate electricity. Depending on the operation, surplus electricity may be sold to the grid or else used to offset on-farm electricity usage. Heat generated during electricity generation can also be recovered.

Anaerobic digestion with subsequent biogas capture allows for the destruction of methane through combustion. Methane is a potent greenhouse gas (21 times greater than CO_2) (EPA, 2006) and its on-farm combustion can sometimes qualify for greenhouse gas credits. Combustion can be through a simple flare system and doesn't require an engine-generator or a boiler. (However some heat recovery system is usually necessary in Northeast and Midwestern climates to maintain reactor temperature).

On-farm co-digestion of imported organic wastes not only benefits the farm through the collection of tipping fees and increased biogas production, but society in general by diverting these resources from landfills where they are a liability. By co-digesting organic wastes in digesters, their energy can be harvested, the nutrients recovered for on-farm use and their greenhouse gas generating potential reduced.

1.3 Report objectives

The objectives of this report are to:

- Collect, assess and synthesize information on small-farm AD technologies and barriers to implementation.
- Educate a potential adopter of AD to inform them of whether it is the right technology for their particular situation.
- Provide a resource for policy makers when they are making decisions regarding funding digesters or developing incentive programs and policy.

1.4 Report limitations

Before presenting some of the available small farm anaerobic digestion technologies and the issues concerning them, it is important to note that there are some limitations of this report to take into account.

One critical limitation of this analysis is the assumption that the digester is operational year-round. Prolonged reactor down time kills off the population of operative microbes and it can take several weeks to reestablish a healthy microbial environment suitable for efficient anaerobic digestion. In addition, anaerobic digestion systems are generally capital intensive, and operating them part-time only makes the payback period longer.

This analysis is geared to the Northeast where dairies tend to be smaller, and similar climatic conditions prevail. That is not to say that the provided information is not relevant to dairies in other regions; more that other options, challenges and requirements may be present in other locations. Specific to the Northeast and Midwest, covered lagoon digesters are not considered. These types of digesters do not remain as effective under winter conditions as other designs.

The economic analysis component of this paper is limited to projects that involve the use of an engine-generator. Policies to improve the economic returns of digester systems have primarily focused on energy production as this also pursues the goal of increasing renewable energy production. Many anaerobic digestion economic analyses consider the benefits of using post-digested separated solids for bedding; however this option was not included as solids separated from raw manure can also be used for bedding.

Community or centralized digesters where manure is trucked or transported from several farms to a single centralized digester, are not considered in the economic analysis component of this paper (Part 2), as the variable of manure/effluent transportation expense, is highly site specific. However, it is discussed in Part 1 in more general terms.

2.0 Current technologies for small farm anaerobic digestion

The technology behind anaerobic digestion is very scalable, and in fact much research has been performed with bench-top and pilot-scale projects. The technology used in large scale anaerobic operations is also applicable to smaller scale projects; though whether a particular technology is suited for small scale operations is more a question of economic rather than technological limitations.

Co-digestion of non-farm substrates, traditionally land-filled or otherwise disposed of, is a trend that is increasing. Through adding additional organic wastes, the biogas yield of a digester can sometimes be significantly increased, and potentially a tipping fee can be charged. Additional non-farm substrates can be added to reactors regardless of size, meaning that it is an option available to small farm systems. However, storage for incoming materials to equalize flows, and larger effluent storage for the increased volume of digested material (manure and the added organic material), is necessary.

A primary limitation to anaerobic digestion that is more likely to be found on a small farm is the lower moisture content of the manure. Usually large farms have free-stall housing systems where less bedding is used, resulting in a more liquid manure . Generally, smaller farms are more likely to have housing systems such as tie stalls where the collected manure is mixed with more significant amounts of bedding, resulting in manure that can be too dry for conventional anaerobic digestion, without dilution.

2.1 Digester system types

The following sections outline a basic description of the three most common digester types; plug flow, mixed and fixed film. Unheated covered lagoons (a fourth type of reactor) are not discussed here as they are not considered viable for the colder climates of the Northeast and Midwest when renewable energy production is a primary goal. High solids digestion is also not considered as the farm scale applications have not yet been demonstrated.

2.1.1 Plug flow

The first anaerobic digesters constructed on dairy farms in the U.S. were plug flow digesters, and subsequently many systems have been built and are operational in New York State. The primary reason for their wider-span adoption is plug flow digesters are comparatively low equipment and operating costs (not necessarily providing the most economic benefit) to mix digesters.

The theory of plug flow digesters is just as the name suggests; influent material is introduced at one end of the digester and flows linearly, like a plug, through the digester and exits at a point of time in the future that equals the digester's hydraulic retention time (HRT). The design HRT in most plug flow digesters is about 21 days; HRT is calculated by dividing the digester treatment volume by the average daily volume of influent digested. The aspect ratio for plug flow digesters normally ranges from 4 to 6:1.

A key to the success of this system is correct moisture content (12 percent total solids or very close thereto) of the influent material; raw dairy manure can fit this requirement perfectly. However, influent that is too dry (possibly due to bedding influences) will not flow properly through the digester and material that is too wet (too much dilution water) will result in partitioning of some solids. Some will settle and some will float reducing the effective capacity and therefore reducing the HRT.

Plug flow digesters are generally constructed below-grade using cast-in-place concrete to construct the digester vessel. Insulation is added to the exterior walls of the vessel before backfilling to reduce the system's parasitic heat load. The tops are either concrete (either pre-cast or poured-in-place) or flexible membrane.

2.1.2 Complete mix

Complete mix digesters incorporate agitation systems in digester vessels and are mainly utilized in scenarios where additional substrates are co-digested.

In New York State, many farmers are interested in mixing food wastes with manure due to:

1. The increased biogas production potential the mixture produces.
2. The associated tipping fees for allowing food waste generators to unload their byproduct on the farm.

Food waste can have a solid content that is significantly greater or less than raw manure, so when combined with manure the resulting mixture needs to be mixed in the digester to help keep the solids in suspension or material flowing through the vessel.

The electrical demand of the mixing units should be considered when designing a mixed system. The electrical energy the agitators consume increases the system's overall parasitic load thus reducing the net energy available for sale to the electrical grid. For estimation purposes, parasitic loads for mixing and pumping represent approximately 10% of the electricity produced by a digester-generator system.

The HRT of mixed digesters varies at the micro level from manure particle to manure particle. Some particles of manure will remain in the digester for greater than the theoretical HRT while some will short-circuit due to the agitation process and exit sooner.

In New York State, farms desiring to benefit from the Net Metering Law are limited to importing no more than 50 percent (by weight of the total digester influent) food waste for co-digestion with manure. Different food wastes contain different levels of nutrients (nitrogen, phosphorous, and potassium) that must be considered when assessing the impact importing food waste has on the farm's ability to comply with their comprehensive nutrient management plan (CNMP). Technologies originally developed for treating municipal wastewater are readily available for removing excessive phosphorous from manure (and a manure-food waste blend), but the economics of the implementation of such systems on-farm is not well established and unfavorable at this time.

2.1.3 Fixed-film

A fixed-film anaerobic digester is a digester that contains media within the treatment volume of the digestion vessel. The purpose of the media is to provide surface area for operative microbes to grow and propagate with the overall goal of reducing the HRT while maintaining a reasonable level of biogas production. The media can be constructed of plastic, polypropylene or other non-degradable materials.

Digesters using fixed-film technology are targeted to treat dilute slurries such as the liquid effluent from a solid-liquid separator (about 5 percent TS) or from an alley flush or flush flume conveyance system (1 percent TS or less). The HRT is usually three to five days.

A fixed-film anaerobic digester at Farber farm (a 100 cow tie stall dairy farm) in New York State operated successfully for 18 months without incident (Wright and Ma, 2003). During the operational period, it was found that sufficient biogas production existed to maintain the digester at target operating temperature (100°F) during the winter months. The generated biogas was used to fuel a boiler that in turn provided heat to a shell and tube heat exchanger for digester and flushed liquid heating. Methane production per unit volume of influent was lower than other types of digestion due to pre-digestion solids removal.

In another example, a larger fixed-film digester has been in operation for several years at the 600-cow University of Florida dairy research farm near Gainesville, Florida. A flush system is used to convey sand-laden dairy manure from the barns to a passive sand-manure separation system, where sand is settled and subsequently removed. Effluent from the sand separation system is processed in a fixed-film digester. This digester operates at near ambient temperature; no supplemental heat is provided. The system would not be appropriate for New York State due to the lack of a heating system. If a heating system were added, the parasitic heat load associated with warming digester influent to operating temperature would not likely be met by the heat value of the biogas generated.

2.2 Centralized/community anaerobic digestion systems

Another option for small farms is to "share" an anaerobic digester with one or more other farms. Manure from the participating operations is transported to a centralized location where it is processed in a larger digester. Collected effluents from the digester are then transported back to the participating farms to be used as fertilizer.

There are several advantages to such a system. Primarily it spreads the capital cost of a digester over several users, allowing them to take advantage of economies of scale. Usually as systems increase in size their cost per unit of production goes down. Larger engine-generators are more efficient and larger digesters are more able to supply consistent biogas.

Another advantage is that the expertise/time requirement to operate the digester can also be shared among the farms, or possibly taken over by a third party. Successfully operating a digester requires a significant investment of time.

A community AD system could also be a means for farms with an excess of nutrients to mitigate their runoff problems. Under such a community system where manure is trucked to a centralized location serving two or more farms, the effluent and byproducts of digestion are usually shipped back to each farm. However if farms that do not have an excess of nutrients are a part of the community system, they could receive more of the effluent to help balance the nutrient needs. Land application of the effluents and residues of AD is usually an important step in the application process.

In an EPA report (EPA, 2002) two other advantages to community digesters are identified; additional financing opportunities, and marketing leverage. Larger digester projects may qualify for additional loans and grant projects, and may have an easier time securing financing. If a digester produces a significant amount of energy, they may be able to negotiate more favorable rates for electricity sales than a smaller operation.

In some parts of Europe centralized anaerobic digesters are becoming more common. The waste from several operations is collected, along with other feedstocks from agricultural and non-agricultural sources. In many instances excess heat is also distributed for residential usage.

However in the U.S. the cost of moving the manure from the farm, and returning effluent to it, compared to the relatively low value for the energy, usually makes such projects uneconomic. The energy density of manure is relatively low and trucking costs can easily outweigh the benefits of centralized digestion.

A community digester feasibility study was conducted for Lewis County New York (Gooch et al., 2010) to potentially handle the manure from 25 dairies located within an 18-mile radius of Lowville, NY. These farms included a significant number of dairies that could be classified as small, as well several larger operations. Also included in the analysis were additional sources of biomass for co-digestion and tipping fee collection. The report found that a project owned trucking fleet with an estimated capital cost of $1.5 million and annual expenses of $420,000, or contracting with a private company ($1.3 million annual expense) made the project not economically feasible. For power sales in the price range of $0.08 to $0.18 per kWh it was found that break even tipping fees were between $9 to $21 per ton. This range was found to be somewhat higher than tipping fees being paid by the non-farm biomass supplier considered for the project, but substantially below the average tipping fee of over $70 per ton charged by landfills in the Northeastern U.S.

3.0 Hurdles to implementation of small farm anaerobic digestion

Before undertaking the construction of an anaerobic digestion system it is critical that the farmer establish whether such a system is practical or impractical for their particular situation. There are numerous technical, financial and regulatory factors that need to be considered before investing in an anaerobic digester. It is also important that a digester is seen as a part of the farm system, and not just as a piece of equipment. The purpose of the anaerobic digester needs to be clearly established; is it to be used to generate electricity or biogas for on-farm use? Or is it strictly to help reduce odor and pathogen load? A clear purpose and understanding of how digesters fit into the farm system is a first step to determining whether anaerobic digestion is right for a farm.

3.1 Characteristics of a farm

Before deciding on what sort of anaerobic digester technology is appropriate, or even whether anaerobic digestion is a prudent investment for a farmer, it is important to consider the characteristics of the farm itself. Important considerations are the manure (feedstock), and how the byproducts of AD can be used on the farm.

3.1.1 Size of a farm

Generally the more animals a farm houses, the more economically feasible an AD system becomes. Larger operations produce more manure, tend to already have manure handling systems, have a greater need for the byproducts of digestion, and the resources of time and money to dedicate to building and maintaining a digestion system. The economies of scale favor larger farms.

The environmental regulations regarding how animal waste is dealt with are under the Concentrated Animal Feeding Operations (CAFO) regulations. These regulations specifically deal with how manure is handled with a goal to protecting water resources in NY state. Farms with less than 200 cows are considered small CAFOs and are generally not subject to the regulation; wheras large (>700 cows) and medium (≥200 and ≤ 699 cows) CAFOs are (though medium CAFO designation does not apply to most states). Though increasing size generally improves the economies of scale, some farms have determined that it may be beneficial to maintain their herd size below the CAFO threshold to avoid being subject to the significant capital cost associated with complying with the regulations.

Another consideration of farm size is land area. If using co-digestion, the nutrients contained in the imported substrates need to be accounted for by the farm's Comprehensive Nutrient Management Plan (CNMP). If a farm is already limited by their CNMP, dealing with additional nutrients can be challenging. It is generally not economic in the U.S., but in other jurisdictions such as Germany where there is an incentive in place, excess land can be used to grow additional, "energy crops," that are added to the digester to boost methane production.

3.1.2 Animal housing

Animal housing can greatly influence the economics of anaerobic digesters, and can dictate what type of reactor design is possible. A requirement of anaerobic digesters is the regular addition of manure/feedstock. The anaerobic digestion process is a delicate balance between the acid forming and methane forming phases. Without replenishment of the feedstock this balance is broken as substrates are consumed and microbial populations starve out. And since it can take several weeks to re-establish the correct populations of microbes, starting and stopping reactors is not a feasible option. Housing systems where manure is only seasonally collected such as pasturing are thus not well suited for anaerobic digestion. Ideally a system will have an influent tank that is used to part to balance the loading of the reactor.

The type of digestion system used can also be partially dictated by the solids content of the manure, which in turn can be set by the type of housing used. Generally manure is classified into three types based on solids content. Manure excreted by dairy cows is typically 10 to 13% solids (ASABE, 2010). Liquid manure is generally defined as less than 10% solids. Liquid manure is generally created by adding wash/rinse water to raw manure. Semi-solid manures generally range from 10 to 20% solids content and this generally results from the addition of bedding and other materials, without significant washwater. Solid manure has greater than 20% solids and is a result of draining the liquid from the manure and/or adding bedding material.

Generally diluted manure results in better digestion efficiency. Excess water reduces the concentration of nitrogen and sulfur compounds which can produce compounds that inhibit anaerobic digestion (Burke, 2001). Liquid manure is usually produced from freestall housing with solid or slatted floor alleys, with or without deep pits. Manure is usually handled by automatic systems which scrape or flush it into receiving pits where it can be pumped to a digester influent tank or long-term storage. A digester influent tank serves to equalize the flow to the digester.

Lack of long-term manure storage prior to a digester project means that projects generally cannot qualify for carbon credits, as a pre-existing manure storage system that generates methane is generally necessary to be able to demonstrate a post-project methane reduction. Digester projects also typically have associated storage for the post-digestion effluent.

Freestall housing can also produce semi-solid manure, when bedding is mixed in with the manure. Milking center wastewater is generally kept separate, and depending on how liquid the manure is, it can be conveyed to storage either through pumping or mechanical scraping.

Solid manure is usually found in stanchion and tie-stall barns and bedded pack systems. The manure consistency will depend on the amount and type of bedding used (whether the bedding consists of long straw or hay). Typically in bedded pack systems, the solid manure is cleaned out several times per year, where it is either stored or spread on the field, depending on the season/conditions making it unsuitable for feeding to a digester. Stanchion and tie stall barns usually have daily removal and spreading of manure which is an acceptable frequency for digestion; however, the manure tends to be too solid for typical reactors, though there are digester systems that will work with the product. Additionally dilution of the manure with post-AD separated liquid may be another option.

Sand bedding systems can cause undue wear on the pumps and equipment used to handle the manure. Sand can also settle out in digesters reducing the effective volume of the reactor and subsequently the hydraulic retention time of the manure as it passes through the system.

3.1.3 Feedstock quality

The quality and characteristics of the manure itself can affect the digestibility, and thus the yield of methane. Because manure is a mix of components whose ratio can change depending on the formulation of the diet of the dairy cows and the addition of bedding material, it is important to be able to characterize the manure.

Arguably the most important consideration is the carbon to nitrogen ratio (C:N ratio). Generally a C:N ratio of 15 to 1 to 30 to 1 is considered good for anaerobic digestion (20 to 25 to 1 is considered optimum (Burke, 2001). If the ratio strays too far from this range digestion will not be optimized and may be incomplete. Excreted manure C:N ratios can vary considerably depending on diet but typically have a value of 20:1.

Ammonia is a component of raw manure, and its concentration is generally increased in a digester by approximately 12 to 40% (Gooch et al., 2007) as organic nitrogen is digested and ammonia produced. If ammonia concentrations rise above 4,000 mg L^{-1} (Chen et al., 2007) they can inhibit the methanogenic organisms that produce biogas. It is important that the pH of the digester stay in a consistent range. Outside of a pH of approximately 6.5 to 8, methanogenic organisms can be inhibited.

As discussed in the section on animal housing, the moisture content of the manure is important to digestion. Manure that has been previously dried, loses a portion of the volatile compounds that are converted to methane.

Anaerobic digestion is dependent on a healthy microbial community. The presence of compounds that could negatively affect this community will also affect methane production. Toxic compounds commonly found in manure include antibiotics, footbath chemicals such as copper sulfate and formaldehyde, and Monensin (an antibiotic added to a cow’s diet to increase feed efficiency). These compounds can impact digester performance, however they are not usually a problem. Farmers need to be aware of the effects these substances can have on their digesters and manage their operations to minimize any impact.

3.1.4 Location of farm

The location of a farm can also affect the feasibility of anaerobic digestion. If there is a cluster of small farms, or a smaller farm is close to a larger operation, it is possible that a community digester could be feasible by sharing the cost of a system. However the possible economic benefits of community digesters can be outweighed if manure trucking expenses are too high due to increasing distance between farm and digester.

Farms of all sizes with digesters could benefit from a ready source of waste organic material that can be co-digested. A farm would get the benefit of increased methane generation, as well as the option of collecting a “tipping fee” from the originator or handler of the organic waste. Larger farms have more manure to buffer periodic loading with food waste if a steady supply or storage is not an option.

Another hurdle related to the location of an anaerobic digestion project is the proximity to three phase power lines. Though not usually an issue for smaller operations, larger generators that sell to the grid may be required to hook up to three phase power, which may or may not be readily available (Dowds, 2009). New York State has limited the cost to hook up to the grid to $5,000 for most project circumstances. However if generation exceeds 20% of the capacity of the feeder line, the generator is responsible for costs of upgrading the power infrastructure needed to accommodate the generation. Depending on location, upgrading the grid is an expense that can run into the hundreds of thousands of dollars.

A farm’s location and size can also greatly influence the number of odor complaints. Prevailing winds can carry farm odors great distances. Encroachment of residential and recreational properties onto former farmland greatly increase the likelihood of odor complaints.

3.2 Technical issues

Anaerobic digestion with associated electricity generation can be a complicated series of many steps and processes that all need to work well together for the system to perform reliably. Technical problems associated with ensuring the correct operation of a digester are not limited to small farm systems, and many problems are common to digesters of all sizes. It should be noted that technical constraints are generally not seen as limiting to the spread of AD technology. Trivett and Hall (2009) identified several technical considerations that need to be addressed before an AD system is installed on a farm, or that should be addressed to facilitate the spread of small and large AD systems across the country; these are addressed below in sections 3.2.1 through 3.2.3.

3.2.1 Design and construction considerations

Sizing a digester requires a detailed analysis of the influent material if co-digestion is planned. This requires a good enumeration of the expected volumes of feedstock, its characteristics, and the type of animal housing employed. Considerable work has been done for larger operations, but small farm systems are much less common, requiring more engineering expertise and customization of designs.

As digester tanks for small farm systems tend to be smaller, there is the possibility that tanks can be constructed off-site and then shipped to the farm, as opposed to being built on-site. Analysis of the cost of shipping vs. on-site construction needs to be conducted. Off-site construction of tanks has the possibility to reduce the cost of system installation, if enough demand is created.

If tanks are to be shipped and or pre-made, there is the possibility that non-traditional materials can be used in their construction, both to save weight during shipping, and to increase manufacturing possibilities off site. Such reactor designs need to be tested before widespread use.

Another major benefit of using transportable tanks is the ability to treat the system as a piece of farm equipment that can be sold. If digester operations do not succeed (for any number of reasons) it is then possible to relocate the digester to another farm, rather than simply being stuck with a vessel with no resale value. This limits the amount of "lost capital" that the farm takes on. There is also the possibility of up-scaling the size of the operation by obtaining larger, or more digester vessels.

3.2.2 Operational considerations

As there are few small scale digesters located in the Northeast (see Section 4.0), considerable work needs to be done to ensure that new designs can handle the seasonal heating requirements.

The optimal operational temperature of a reactor needs to be maintained to ensure efficient digestion. Heat loss through the walls of the digester can be estimated with theoretical techniques, but should be verified through experimental testing under a variety of climate conditions. The seasonal change in heating requirements needs to be determined so that heating systems can be correctly sized.

Small digester designs will also require careful consideration of the maintenance and cleaning requirements, of both the digester and the systems used to maintain temperature within the digester. Simplified maintenance is particularly crucial in small operations where a farmer may not have the labor resources to dedicate as much time to the digester as a large operation.

Many of the small-scale designs popular around the world are located in climates where extremely cold winters are not a factor, and decreased biogas production (due to temperature drop) can be tolerated. If maximum biogas production is necessary to maintain financial viability, temperature control is a necessity.

3.2.3 *Energy production considerations*

The energy content of substrates that are potentially co-digestible in anaerobic digesters needs to be evaluated, to determine how much of an increase in biogas can be realized. This information is particularly necessary in evaluating marginal projects, where there is less room for error in predicting expected energy yields from the digester.

Electricity generation on small farms is currently problematic as there are fewer suitable engine-generator options available. Most of the major engine-generator manufacturers have focused on larger engine-generators as that has been where the demand is. A listing of manufacturers and their smallest system designed to handle biogas is presented in Table 1.

Table 1. A selection of engine-generator manufacturers and their smallest biogas systems.

Manufacterer	Model #	Type	Rating (kW)
IPOWER	ENI 20	Internal Combustion	20
Capstone	C30 HP	Microturbine	30
Catterpiller	G3306	Internal Combustion	72
Mann	E0834	Internal Combustion	62
GE Jenbacher	Type 2	Internal Combustion	250

An added difficulty for small farms is that cleaning the biogas (predominantly H_2S reduction) before use in an engine-generator involves significant expense, whereas using raw biogas in an engine-generator can greatly shorten its useful life. In some cases operators have found it more economical to repair the engine-generator, than to install biogas scrubbing equipment (Dowds, 2009), however this is usually not advised. This is usually a question of the economies of scale and goals of the farm, where larger operations can more readily afford the necessary gas cleanup equipment. Clean-up technologies for biogas need to be further studied for application in small farm systems. Removing H_2S adds an additional step to the process, requiring careful monitoring and management. Typically farms send samples of the waste oil from the engine-generator oil changes to the engine manufacturer or other labs where it is analyzed for composition. The presence of metals or other compounds can indicate premature wear of engine components and direct maintenance/repair procedures accordingly. Typically farms with no biogas cleanup equipment change their oil more frequently.

During routine operation and maintenance of engine-generators it is often necessary to shut down the engine. During this time the biogas is typically flared off. Similarly during periods of peak demand for electricity it would be advantageous to be able to burn more biogas from storage. However biogas storage is an expensive proposition. Compression of biogas for storage is also expensive as the compressors require significant power, and raw biogas is corrosive to such equipment. Structures with a floating roof are often used, however they too are expensive to construct and offer limited storage.

3.3 Economics

The economic feasibility of AD is the most important factor when a project is under consideration. Whether or not a project makes economic sense and can succeed, is highly dependent on the costs associated with construction and operation, and with the returns that the project can provide.

3.3.1 Capital costs

Construction costs are a considerable barrier to anaerobic digestion at any scale of production, and particularly at the small farm level. In fact, construction costs and return on investment are the most frequently cited barrier to the spread of dairy anaerobic digestion (Dowds, 2009). Several factors such as system complexity, lack of existing storage and manure handling equipment can contribute to the high capital costs associated with AD.

System cost will vary with system complexity. The more complex a system is, the more infrastructure is necessary with its associated cost. If a farm is already setup to handle liquid manure, that is one less expense. However if the farm utilizes housing technologies that require solid handling of manure, manure handling becomes an associated cost of adding in a digestion system.

Additionally, biogas utilization can greatly affect construction costs. Systems ranging from simple flaring of the biogas, to extensive treatment and removal of contaminants for direct sale of biogas to the utility have widely divergent costs associated with them. In a review of 38 AD systems, the USDA Natural Resources Conservation Service (NRCS) found that 36% of the capital costs were associated with the electrical generation equipment and that the majority of maintenance costs were associated with this equipment (NRCS, 2007). This review was of generally larger sized projects and so for small farms, this percentage could be much higher. At such a small scale, specialized engine-generators that are capable of handling biogas are much less common, and so are much more expensive on a per cow basis.

The high level of complexity, diverse farm conditions, and different farmer expectations for AD result in a high level of customization for each project. Careful design and consideration needs to go into planning AD systems to ensure that they can be operated successfully. High levels of system customization, means higher design and construction costs. In addition, because the market for anaerobic digesters is currently small, (and for small farms even smaller), there are few technology providers available. Fewer technology providers translates into fewer options available and less competition between companies.

Other factors working against small farms, are the savings that can be realized with economies of scale, and certain fixed costs associated with anaerobic digestion regardless of the operation's size. Larger farms with a correspondingly larger budget, can realize savings in construction, in addition to having more available construction options. Considerably more expertise is available for large farm anaerobic digesters, and there are lots of successful operations to draw advice from.

Fixed costs such as permits, and interconnection are expenses that must be paid regardless of the size of operation. Grid connected projects usually need to undergo a review process which can add a significant cost for a small farm to bear. Small farms with small generating capacity would most likely be able to hook up to the grid using single phase lines; however, for larger projects three phase hookup is usually required. As three phase hookup is less common, the project may have to pay the cost of installing new power lines.

Occasionally local permits need to be obtained before construction can begin, and if the project is unusual, additional time may be necessary to process the application. If materials other than manure are to be digested, further permitting is also usually required.

The capital cost of a digester project will vary considerably depending on the technology selected, the sophistication, economies of scale, and conditions specific to each farm. AgSTAR has estimated the per head cost of constructing a digester to be between $750 to $1,150 for complete mix systems with biogas engine-generators (AgSTAR, 2009). However these estimates are based on projects greater than 500 cows. NRCS (2007) estimated a per head cost of $543, however their analysis had several covered lagoon style systems which are not directly comparable to plug flow or mix type digesters.

Program incentives as well as grants at the state and federal level exist to encourage the implementation of AD, and many of the systems in operation today relied heavily on these programs. As with limitations on the expertise and time required to operate a digester the process of applying for programs and grants is proportionally more difficult for smaller operators with less time to dedicate, and other competing demands on their time. In addition there may be fixed costs associated with applying for grants such as energy audits, which cost the same regardless of operation size.

3.3.2 Operation and maintenance costs

Once an anaerobic digester is operational there are considerable operation and maintenance costs associated with keeping it so.

Maintaining and ensuring that the digester and all the associated equipment is operating properly (particularly pumps and agitators) requires daily checkups. For digesters it has been estimated that it takes one-half hour per day and one-half day per month to maintain the digester (Scruton, 2007). During the initial startup when operators are learning the nuances of the system, additional maintenance calls may be required from the company that constructed the system. Maintenance calls may also be necessary in restarting digesters following cleaning out. This time and expertise requirement results in relatively high management costs (expertise-related expenses).

If an engine-generator is a part of the system, maintenance costs can be significant. In a study, the NRCS found that most of the operation and maintenance costs were associated with the electrical generation equipment (NRCS, 2007). There are a number of reasons for this. An engine-generator is a complex piece of machinery with lots of moving parts subject to wear and tear. The oil must be changed regularly to ensure the engine lasts as long as possible. If the farm is dependent on the energy produced by the engine-generator, they may be subject to significant electricity demand charges from the utility, when the engine-generator is down for maintenance. These demand charges may be so high as to justify maintaining a backup diesel or other power generator onsite. Biogas also contains H_2S gas which can be extremely corrosive to the metals of which the engine-generator is manufactured. Some engine-generators require that raw biogas be scrubbed to reduce the H_2S content. The operator can sometimes forego scrubbing depending on the quality of the biogas from their reactor by increasing the frequency of engine oil changes. However a scrubber is usually required which represents an additional piece of equipment/process that needs to be maintained.

Other possible expenses related to operating an engine-generator are insurance fees charged by the electrical company. In some states electrical companies charge generators insurance fees, to protect themselves in case of worker electrocution during power outages. In addition, farmers may be subject to stand-by provisions which require a customer to reimburse the company for money they would have made selling electricity to them. Projects which qualify for net metering in New York State are not required to pay insurance or standby charges.

Other energy expenses related to digester operation include the parasitic power required to mix the digester, and possibly supplemental energy required to either warm the reactor up to the correct temperature when it starts, or to make up the difference if biogas production or heat recovery is not sufficient.

3.3.3 Value of energy produced

Depending on the system selected and the needs of the farm, AD can produce different forms of energy, which may be either used on-farm, or in some cases, sold for off-farm use. Collected biogas can be put to several different uses. It can be:

- burned directly for on-farm heating needs (wash water, space heating, etc.)
- treated to remove CO_2, H_2S and other contaminants and sold to a utility for off-farm use
- used to generate electricity for on-farm use, or sale to a utility

The economies of scale and the value of the energy will determine the best option for a particular farm.

To establish the value of the energy produced a number of questions need to be considered. How much energy is required by the farm? How much does it cost to purchase the required farm energy? How much energy could be produced on-farm? How much will it cost to produce energy on-farm? How much money could on-farm produced energy be sold for?

The typical range of electrical demand for a small farm is dependent on a number of factors including the style of production, the number of cows, climate, etc. Because these factors can vary greatly, published values of typical electrical energy usage span a wide range; from between 200 to 400 kWh $year^{-1}cow^{-1}$ up to 1,200 kWh $year^{-1}cow^{-1}$ (USDA, 2012).

Another important consideration of the electrical demand is the timing or frequency of use. On large operations with nearly 24-hour milking schedules, electrical demands are relatively constant throughout the day, as opposed to smaller operations where energy use peaks during milking periods, followed by much reduced demand. Trivett (2009) states that "for the volume of biogas that can be produced on a small farm, there may be enough electrical energy generated to supply the farm's average electrical demand. In theory, this could allow the farmer to operate off the grid, but the trade-off between equipment costs to supply peak electrical demand versus the cost of equipment to supply only the average load is significant."

The amount of biogas and resulting electricity that the farm can produce depends on the feedstock available for the anaerobic digester. Will the digester operate strictly on cow manure? Or will additional feedstock be added? How much manure is available? Is it solid/liquid? What is the energy content of the manure and any additional feedstocks? Once these questions are answered it should be possible to estimate how much biogas a digester can produce and in-turn how much electricity.

From the gross production of biogas the net production of energy can be estimated. Efficient anaerobic digestion requires temperatures above ambient, and so a percentage of either the biogas, or waste heat from combustion in an engine-generator must be returned to the reactor to make up heat loss to the environment, and heating of influent feedstock. The amount of heat required is dependent on the climate/time of year. One estimate is that digesters consume about 1/3 the amount of electrical energy they are capable of producing regardless of size (Mehta, 2002), however this number was based on using electricity to maintain digester temperature, rather than recovered heat which is typical for most digesters. In an analysis of seven on-farm AD systems (Gooch et al, 2011) found parasitic AD energy use of 6.8 to 29%. However the 29% was from a farm in which the engine-generator was out of commission for a majority of the monitoring study. The 6.8% value represents a farm with a high level of co-digestion that separates solids prior to digestion. The remaining farms saw values that averaged 11.6%.

The cost of producing energy from biogas is not insignificant. Engine-generators need to be specially designed to handle the corrosive effects of biogas. In addition they are generally available in limited sizes which may be too large for small farm systems.

If there is an excess of electricity or biogas available, one option is to sell it to the local utility. However this is not without cost as interconnection fees to the utility for power or gas can be significant, and as these costs are relatively independent of the size of the operation, it can make the cost prohibitive for smaller farms. By law, NY state has limited the cost to the farmer of hooking up to the grid to $5,000, however this does not limit grid upgrade costs that must be borne by the generator if the output of the AD project exceeds 20% of the capacity of the grid feeding the farm. Costs for upgrading power lines can extend into the hundreds of thousands depending on the location of the farm and the local grid. For natural gas interconnection, the fees can be even greater due to the rural locations of farms where access to natural gas lines is more limited.

Once a farm is set up to sell electricity/biogas to the utility, the price that energy commands is an important factor. Depending on the contract signed, net metering may limit the farm to offsetting their use of power from the utility; i.e. the farm can only sell as much power to the utility as they themselves take from the utility during times when the farm does not produce enough power to satisfy all of its needs. Other power selling agreements, such as those in NY, may only give wholesale pricing for the surplus power and not the retail market price. This is in contrast to other renewable energy sources such as windmills and solar panels where feed-in tariff programs can pay a premium above the market price to the generator.

Another significant expense to farms are demand charges that utilities apply for supplying power to the farm. In NYS demand charges are calculated based on the highest power usage 15 minute period per month, which in some cases can represent several thousands of dollars. Power demand when an engine-generator is shut down for maintenance or other reasons increases over typical usage, however the farm is charged a demand rate as if the utility had to supply that much power over the entire month.

An additional consideration is the capacity factor, the electrical energy the engine-generator actually produces versus the maximum potential amount it could produce in the same time period. It is more economic to run at a higher capacity factor, making better use of operating equipment.

3.3.4 Unquantifiable co-benefits

A major reason for installing a digester can be the reduction of odor, to reduce complaints from neighbors. Through AD the compounds primarily responsible for the disagreeable odor (the volatile fatty acids) are digested, leaving an effluent that is much more biologically stable and with much less potential to produce odor. Though this can be a major benefit through improved neighbor relations, it is difficult to place a financial value on it, to further justify the expense of a digester.

Besides reduction of odor, other unquantifiable benefits include reducing the biological oxygen demand and pathogen load of the effluent. These issues are closely linked to ground and surface water quality.

Another direct benefit to the farm that is difficult to place a value on, is the increased flexibility in applying the digester effluent to their fields. Without digestion, the times at which a farmer can field apply may be limited due to odor. Digestate has limited odor and so can be applied over a greater schedule which may benefit the crop and reduce the required storage volume for the farmer. In addition, during anaerobic digestion, some of the organic nitrogen is converted to ammonia-N which is much easier to manage when applied to fields for fertilizer.

Though there may not be a direct financial payoff for these benefits, the avoidance of a fine for contaminating ground and surface water definitely has a value.

3.3.5 Financing

Successful construction of AD systems requires careful understanding and planning when it comes to financing. Because digestion systems are capital intensive, it is usually necessary to secure financing from outside sources. The inability to attract financing is a key barrier to the widespread adoption of AD systems (Gloy and Dressler, 2010). AD systems are a major investment regardless of farm size. Coupled with uncertainty about the rate of return and the economic value of the benefits, securing financing is arguably the most difficult step of implementing an AD system.   A low rate of return from an AD project may not compete with the rate of return of other on-farm investments.

Banks recognize the risk in financing anaerobic digesters. According to the EPA AgSTAR program, approximately 14% of digester operations have failed since 1998 (though most of the failures are not in the recent past). Digesters have no, or at most little resale value, making their collateral value low at best. Failures can happen for a number of reasons which are not all technical. Often digesters are constructed with grants, and once these grants expire, the digester may be unprofitable to operate. Projects and grants to encourage digester development may have limited life-spans making it difficult for the digester to remain economically viable. Additionally farms go out of business or change hands to new ownership that is not interested in operating an AD system.

Another major difficulty with securing financing for digesters is the high lost capital costs. Lost capital is money that is invested that cannot be recovered. Due to the nature of the digester vessels, and the associated infrastructure with moving biogas and hot water, they are usually labor intensive to construct, and cannot be moved or dismantled readily so as to recover value from them if the project is halted.

Revenue from co-digestion is also a potential means of improving the financial viability of a digester project, both through increased biogas yields and through the collection of tipping fees. However experience has shown that securing long-term contracts to guarantee the availability and revenue from imported substrates is not common.

Smaller projects have a harder time proving viability, particularly as there are so few examples of successful operations.

3.3.6 Expertise

Another significant hurdle to small farm AD is lack of expertise. Both in the operation and maintenance, and in the construction and servicing of systems. Even a basic digester without an electrical generator requires careful monitoring to ensure proper operation. Mistakes that require restarting or cleaning out the reactor can take months to reestablish the microbial community, not to mention great expense.

On-farm, a manager/operator must be capable of managing a complex and changing system, and of devoting enough time to the digester. Regular observation and maintenance is required, not just when there are operational problems, but particularly when co-digestion is considered. On a small farm where labor may already be in short supply, finding time to operate a digester many be difficult. It is also a potential reason to consider a centralized digester operation. Under a centralized operation the labor cost of operating and maintaining the digester can be spread between several farms. While some farmers build digesters themselves, a few contract with third-party developers, who have access to venture capital, to build and even sometimes operate the system.

Another significant hurdle to AD in general is a lack of industry support. Though the industry is expanding, a lack of companies with experience installing and servicing farm digester systems was identified as a hurdle to the adoption of AD (Scruton, 2007). Often once a company has constructed the system, it is up to the farmer to keep things operational. And with few formal opportunities for training, necessary skills have to be learned on the job; which makes it difficult for the operator to deal with abnormal conditions.

3.4 Regulatory and environmental

3.4.1 Permitting

Since anaerobic digesters are still new to many municipalities, steps such as securing a building permit or insurance may take longer than expected due to different requirements and approval processes, and potentially, changes in zoning. In addition there may be uncertainty as to which building codes apply to digester buildings and equipment, potentially increasing the cost of construction. Local regulations for electrical safety of small biogas generators need to be verified by the utility, occupational health agencies, and local fire departments.

Further the municipality may not have clear guidelines as to how a farm-based anaerobic digester will be assessed for property tax purposes.

3.4.2 Engineering practice standards

Another potential barrier to AD are engineering practice standards for digesters. Bracmort (2010) states that “A national practice standard that lists performance criteria, safety precautions, technical components, and design elements and has undergone review from a standards developing organization is not available for anaerobic digestion technology. Some producers may be reluctant to make a financial investment in a technology that may or may not meet future environmental and technical requisites."

However, NRCS now has a national standard (NRCS, 2009) that covers anaerobic digestion. Each state NRCS office can then adopt the standard and depending on the situation, make changes to the national standard to make it more stringent. Other jurisdictions such as Canada, may not have a practice standard for digesters.

3.4.3 Net Metering and feed- in tariff regulations

In a net metering power agreement, the producer puts energy onto the grid when they have a surplus, and draws from it when they have need. At the end of the year (or billing cycle) any surplus is paid to the farmer (whereas farmers pay at the end of any month with a deficit). Often, surplus power is valued at a wholesale rate which provides little incentive to an operator to maximize their engine-generator output.

Remote net metering has been enacted in NY state, and under this model, multiple meters under the same account are allowed to be offset by the power produced by the engine-generator. This allows producers to offset more of their purchased power, as often farms have several meters (separate meters for residential, remote wells, and barns etc.).

In other jurisdictions, feed-in tariff (FIT) regulations provide an incentive by paying a premium for renewable energy. Under a feed-in tariff agreement, all the electricity produced at the engine-generator is sold at the premium rate, and the energy used on farm is purchased at market rates with the difference providing a source of income for the project. Rates in Ontario, Canada are $0.19 per kWh, whereas under Vermont's FIT program rates have been $0.16 per kWh.

Policies to foster on-farm biogas-based electricity generation should allow producers to earn a reasonable amount of money for electricity produced in excess of their demand. Feed-in tariff programs are common for other renewable energy sources such as wind and solar, but are not as common for biomass based power.

3.4.4 Carbon credits

To help curb greenhouse gas emissions from power plants, the Regional Greenhouse Gas Initiative (RGGI) was established in 2005. The initiative oversees a cap and trade system in which 10 northeastern U.S. states participate (and in which several other states and provinces are observing). The initiative requires fossil fuel-based power plants with 25-MW or greater generating capacity to purchase offsets to meet their compliance requirements or else pay a fine.

Dairy farm operations qualify for greenhouse gas credits through reducing the escape of methane gas, which is released through the decomposition of manure (as well as directly from cows). Methane is over 21 times more effective in trapping heat in the atmosphere than carbon dioxide (EPA, 2006). Anaerobic digestion of the manure enables methane capture, making it available for energy production, or even simple flaring and can reduce a farm's greenhouse gas impact significantly.

If a farm can qualify and become able to sell their carbon credits, they could potentially realize significant income if carbon markets recover. It should be noted however that carbon credits are based on offsets, rather than absolute amount of methane or carbon produced. Offsets are determined by first estimating baseline carbon emissions, and then subtracting the measured carbon emissions after a digester is operational. The determination of baseline emissions is laid out in the application guidelines of the carbon trading agencies.

As part of the agreement to sell carbon credits, greenhouse gas reduction must be verified periodically by an approved verifier who reviews records, gas flow measurements, operational procedures, etc. Producers are required to maintain documentation and their operations may be inspected to ensure compliance. The costs to verify compliance are significant and can run from $3,000 to $5,000 for the initial verification, and annual carbon audits cost $700 to $1,000. The costs are relatively fixed and so for smaller farms they are potentially more onerous.

Carbon credits are also difficult to work with because of market volatility in their pricing. Credits traded on the Chicago Climate Exchange (CCX) reached a high of $7.50 per metric ton CO_2e in May of 2008, but fell to a low of only $0.10 per metric ton CO_2e in November of 2010 when trading ceased. Greenhouse gases are typically referred to in units of CO_2e or CO_2 equivalent, as other greenhouse gases (such as methane) have higher greenhouse gas potential. The federal government has not passed cap and trade legislation which has hindered the market for carbon credits, however California is beginning to implement its own program. The California Air Resources Board will oversee the market, which is due to start operations in 2013.

Small farm systems may be shut out from benefiting from carbon credit pricing as to qualify, since the farm has to have a manure storage system that produces methane, before the implementation of the digester project, since it is based on baseline emissions. Often because of the way small farms handle their manure they do not produce much methane and therefore have little in the way of methane emissions to offset. Placing a large value on methane reductions could actually hurt the economies of smaller farms in comparison to large ones, as small farms without long term manure storage are unable to take advantage of carbon credit sales, the way farms with a methane producing storage system can.

3.4.5 Co-digestion regulations

For land applied AD effluent, there is usually no need for extra permitting, however this is not always the case if co-digestion materials are included.

New York Department of Environmental Conservation (DEC) has solid waste regulations (NY 360) that may pose additional permitting requirements for farms processing food wastes. Typically, importation of food waste is regulated through a farm's CAFO permit, however if a farm does not have a CAFO permit (which is generally not necessary for farms of fewer than 700 cows) then they are required to obtain a Part 360 solid waste permit to handle food materials.

In New York State, farms are limited by the Net Metering Law to importing no more than 50 percent (by weight of the total digester influent) food waste for digestion with manure. Different types of food waste contain different levels of nutrients (nitrogen, phosphorous and potassium) that must be considered when assessing the impact importing food waste has on the farm's ability to comply with their CNMP.

3.4.6 Air emissions

The generation of electricity and heat from biogas does have implications for air quality. If engine-generators and boilers are not operated correctly, significant smog producing compounds can be released. In California where air quality is a major concern, it is emissions from engine-generators that are a major stumbling block for new digester projects. Engine certification information is difficult to obtain as engines must be adjusted in the field due to variability in biogas quality and so emissions testing must also be done in the field with prices ranging from $5,000 to $10,000. For engines between 100 and 500 hp, a test at time of installation is required, however, in addition, larger engines (>500 hp) need to be tested every year.

Many jurisdictions lack emergency flaring or venting regulations. Such regulations are important as optimizing the output of the digester and engine-generator usually require maximizing biogas production, and there is usually little biogas storage capability within the system. This is particularly relevant when engine-generators are down for maintenance.

4.0 Current and past small farm anaerobic digestion projects

Many small farm anaerobic digestion projects are associated with research facilities/farms. This is most likely due to the fact that these locations are better able to take the risks associated with constructing these digesters, and have personnel who can be dedicated to maintaining, and evaluating their performance. Often a purpose of these smaller digesters is to demonstrate the feasibility and proof of concept of particular designs.

EPA AgSTAR maintains a listing of digester projects in the U.S. According to this database the three smallest digesters in operation are: Keewaydin Farm, the USDA-ARS Beltsville facility, and Jer-Lindy Farms.

The Keewaydin Farm digester in Stowe, Vermont is a modular plug flow digester that is fed by 75 dairy cows (Figure 4). It uses a model AnD 1B22 system by Avatar (Walnut Creek, CA), that has the capability to handle 1,124 gallons per day (22,472 gallons capacity) of influent with an 18 to 21 day hydraulic retention time, and can be expanded to meet the needs of a larger herd. It can also be broken down and moved in the event the digester is no longer needed and can be financed as a piece of farm equipment rather than more traditional fixed-asset digesters. It has been operational since 2011, and the biogas powers a 20-kW IPOWER Energy Systems engine-generator (no biogas clean-up).

Figure 4. Keewaydin Farm digester by Avatar.

The USDA-ARS facility in Beltsville, Maryland has been intermittently operational since 1994. One hundred dairy cows supply manure to the continuous-stirred tank reactor. The biogas is used to fuel a boiler which in turn provides the heat necessary to maintain operational temperature (100°F). A combined heat and power 15-kW engine-generator was installed but has never been brought online. The biogas is untreated, which has led to difficulties with corrosion of the boiler systems.

Jer-Lindy Farms in Brooten, Minnesota uses a 33,000 gallon induced blanket reactor (Andigen, Logan UT) to treat the manure from its 215-cow herd (125 lactating cows). 7,000 gallons of manure per day is digested, and the biogas is used to fuel a 40-kW engine-generator (modified GM 350). Their digester has been in operation since 2008. Currently, no biogas treatment is used though initially the farm had difficulty with their remanufactured engine-generator prematurely failing. Under Minnesota's current net metering law, power production is capped at 40-kW.

Wagner Farms in Poestenkill, New York operates a mixed digester (CH Four Biogas, Ottawa, ON) to digest the manure from the farm's 350 dairy cows (Figure 5). The vessel receives 6,300 gallons per day and has a 28 day hydraulic retention time. Removal of H_2S is conducted in-vessel through regulated application of oxygen to the air space above the liquid which contains wooden logs as surface area for the sulfur reducing microbes. The biogas fuels a 100-kW MAN engine-generator, installed in July, 2010.

Figure 5. Wagner Farm's digester by CH-Four Biogas.

According to the AgSTAR database there are six anaerobic digesters that were fed by herds under 500 cows that are no longer operational. These projects are outlined in Table 2.

Table 2. Non-operational small farm anaerobic digestion systems in the U.S., as of June, 2012 (AgSTAR, 2012)

Farm	State	Digester design	Year Commissioned	Herd Size	Energy Use	Generator Capacity (kW)
Foote Farm	VT	Modular Plug flow	2005	160	Co-generation	20
Spring Valley Dairy	NY	Manure Activation System		236	Electricity	25
Nordic Farm	VT	Vertical Plug flow	2005	250	Co-generation	65
Cooperstown Holstein	NY	Complete Mix	1985	270	Co-generation	65
Futura Dairy-Waubeek Dairy Cow Farm	IA	Horizontal Plug flow	2002	380	Electricity	50
Kirk Carrell Dairy	TX	Horizontal Plug flow	1998	455	Co-generation	60

These systems all had the capability of generating electricity and in some cases the ability to provide waste heat for on farm uses.

Another NY small farm digester that is no longer operational was located on the Farber Farm in East Jewett, Greene County, NY (Figure 6). The fixed-film digester was installed in 2001 primarily to solve problems with odor emissions. The digester treated the manure from 100 cows, with the biogas produced used to heat water for on-farm use. The digester operated successfully, however the project was ended when the owners of the farm ceased dairy operations (Wright and Ma, 2003).

Figure 6. Farber Farm, fixed-film digester.

Part 2 - Economic Analysis of Small Farm Anaerobic Digestion

A goal of this section of the report is to present results of a cost-benefit analysis of the effects of varying benefits pricing on small farm AD coupled with power generation. A firm understanding of the costs and potential benefits of AD systems is key to making informed decisions on individual projects, and on a larger scale, the policies that regulate and encourage them.

In order to achieve this goal of the paper, a computer model using MS Excel® was developed that estimates AD system operation parameters based on farm herd size. Once the system is sized for the mass and energy production of the farm, the economic aspects of the system can be modeled. Specifically estimates of the surplus electricity, carbon credit and co-digestion incomes can be determined as a function of farm size.

The completed system and economic model was then used to investigate how varying benefits pricing levels and operational strategies (i.e., co-digestion) affect the minimum farm sizes necessary to offset costs with benefits.

Using the model it was then possible to examine how anaerobic digestion incentive programs would affect the economics of small farm anaerobic digestion.

5.0 Model development

The model used to conduct the cost-benefit analysis consists of two closely inter-related parts; a system model and an economic model. The system model was developed to estimate the size and operational parameters of a small farm anaerobic digestion system for given cow numbers. The economic model builds on the system model and estimates costs and benefits associated with operating the system under a variety of benefit pricing points and scenarios. With the developed models it was possible to calculate the costs and benefits associated with varying system size and operational and financial scenarios, and alternatively to calculate the herd size necessary to offset costs with benefits with set benefit and cost pricing.

5.1 System model

The system model of small farm anaerobic digestion starts with the herd population, and from that estimates manure production. In turn, manure volume and co-digestion materials (if added) are used to estimate biogas production. The production of biogas provides a means of estimating the electrical production from combustion in an engine-generator . The assumptions necessary to make these calculations are discussed in the following sections.

5.1.1 Herd population and manure production

The starting point of the model is the number of lactating cows. From this population a default herd size for animals contributing to manure production was estimated based on common ratios of dry cows and heifers to lactating cows found on typical farms (17 dry cows for every 100 lactating cows and 80 heifers for every 100 lactating cows) (Powell et al., 2005). From the herd size and make-up, the mass of manure produced by each cow management group and the volatile solids amount was estimated using published values (ASABE, 2010) presented in Table 3.

Table 3. Total manure and volatile solids production from dairy management groups (ASABE, 2010).

	Manure Production lb/day (kg/day)	Manure Volatile Solids lb/day (kg/day)
Lactating Cow	150 (68)	17 (7.5)
Dry Cow	83 (38)	9.2 (4.2)
Heifer	48 (22)	7.1 (3.2)

For the purposes of stating the capacity of the digester system, lactating cow equivalents (LCE) were used. The manure production of dry cows and heifers was converted into the equivalent manure production of lactating cows on a mass or volatile solids basis depending on the requirement according to the following formulas:

LCE_M for dry cows =

$$\frac{(average\ daily\ number\ of\ dry\ cows *\ 83\ lb\ manure\ drycow^{-1}day^{-1})}{150\ lb\ manure\ lactating\ cow^{-1}day^{-1}}$$

Where: LCE_M = Lactating cow equivalent on a mass basis
83 lb = mass of manure from an average size dry cow (ASABE, 2010)
150 lb = mass of manure from an average size lactating cow (ASABE, 2010)

LCE_M for heifers =

$$\frac{(average\ daily\ number\ of\ heifers *\ 48\ lb\ manure\ heifer^{-1}day^{-1})}{150\ lb\ manure\ lactating\ cow^{-1}day^{-1}}$$

Where: LCE_M = Lactating cow equivalent on a mass basis
48 lb = mass of manure from an average size heifer (ASABE, 2010)
150 lb = mass of manure from an average size lactating cow (ASABE, 2010)

LCE_{VS} for dry cows =

$$\frac{(average\ daily\ number\ of\ dry\ cows *\ 9.2\ lb\ manure\ VS\ drycow^{-1}day^{-1})}{17\ lb\ manure\ VSlactating\ cow^{-1}day^{-1}}$$

Where: LCE_{VS} = Lactating cow equivalent on a volatile solids basis
9.2 lb = mass of manure VS from an average size dry cow (ASABE, 2010)
17 lb = mass of manure VS from an average size lactating cow (ASABE, 2010)

LCE_{VS} for heifers =

$$\frac{(average\ daily\ number\ of\ heifers *\ 7.1\ lb\ manure\ VS\ heifer^{-1}day^{-1})}{17\ lb\ manure\ VS\ lactating\ cow^{-1}day^{-1}}$$

Where: LCE_{VS} = Lactating cow equivalent on a volatile solids basis
7.1 lb = mass of manure VS from an average size heifer (ASABE, 2010)
17 lb = mass of manure VS from an average size lactating cow (ASABE, 2010)

For example, the manure production from a dry cow represents 83 lb/day divided by 150 lb/day or the equivalent of 0.542 lactating cows. Similarly a heifer represents 0.325 lactating cows on a manure mass basis.

Herd population also serves as one of the inputs to estimating the carbon credits available to the farm following digester installation.

The amount of VS serves as the basis for calculating co-digestion capacity and biogas production, and so the amount of co-digestion material is based on the mass of VS rather than just a volume of material. This also makes the results of the analysis useful for other co-digestible materials that have varying VS concentrations. Provided the digestibility of the VS is similar to whey the energy produced will be the same on a VS basis (though the capital cost of storage may vary).

5.1.2 Co-digestion

The capacity of the model system to accept additional organic materials to co-digest, was based on the VS loading rate of the manure. Small farm digesters are ideally as low maintenance as possible which makes high co-digestion rates difficult. Co-digestion can require considerable efforts in monitoring both the flow of materials into the digester and the health of the digester itself; a task that may be onerous for a small farm with a limited workforce. For this reason the VS loading rate as a percentage of the VS of the manure was limited to 25% (i.e. one-quarter of the VS can be from co-digested material).

The material used as an example for this analysis was whey, but the model inputs could be varied to incorporate other materials. Whey is a common byproduct of milk processing and is generally readily available to farms. A 25% loading rate based on volatile solids is also well within stable loading rates for whey as it is readily co-digested with manure. Loading rates up to 50% (on a volume basis) have been investigated (Gelegenis et al., 2007). Based on the ratio of VS for co-digestion a volume of co-digestion whey was estimated based on its density and VS content. Whey was assumed to have a VS content of 59.8 g/kg (Labatut et al., 2011), and a density of 1.025 kg/L.

5.1.3 Biogas production

To estimate the biogas generated with and without additional digester feedstock, the following formula was used:

$$biogas\ rate = VS\ loading\ rate * SMY$$

Where:

Biogas rate is the production of biogas per head per day (L day^{-1}).

VS loading rate is the VS content of the manure (or mix) added per day (kg VS kg^{-1} manure (mix)).

SMY is the specific methane yield of the manure (or mix) (L CH_4 kg^{-1} VS added).

Labatut (2011) showed that the specific methane yields for 75:25 and 90:10 mixes (VS basis manure:whey) were well within experimental error of one another with values that varied only a few percent. Therefore, the SMY value used for the analysis was 242.7 L CH_4 kg^{-1} VS (3.89 ft^3 lb^{-1} VS) added.

5.1.4 Electrical generation

Electricity generation was modeled by taking the estimated biogas production and assuming it was used in an engine-generator. Biogas was assumed to contain 60% methane (CH_4) and methane was assumed to have an energy content of 896 Btu ft^{-3} (Marks, 1978) which results in a biogas energy content of 538 Btu ft^{-3}.

Daily biogas production was converted into hourly production by dividing by 24. The resulting hourly biogas feed rate was multiplied by the biogas energy content which was in turn divided by the conversion rate of the engine-generator to give the output of the engine-generator in kW.

Thermal conversion rates for a range of engine-generator sizes (30 to 295-kW) were obtained from the manufacturer, and used to estimate and develop a ratio of biogas consumed to power produced. The ratios of energy input to power output for select models of engine-generator are presented in Table 4. Conversion rates varied considerably between companies, and engine-generator size, with typically smaller sets having a lower conversion rate.

Table 4. Engine-generator size and energy conversion rates for biogas capable engines from three major manufacturers.

Generator Model number	Type	Size (kW)	Conversion Rate (Btu/kWh)	Conversion Rate (%)
Cat G3306	Internal Combustion	72	13,565	25.2
Cat G3406	Internal Combustion	132	12,718	26.8
Cat G3412	Internal Combustion	177	14,088	24.2
Capstone C30 HP	Microturbine	30	13,100	26.0
Capstone C65 ICHP	Microturbine	65	11,800	28.9
Capstone C200 HP	Microturbine	200	10,300	33.1
Mann E0834	Internal Combustion	62	9,383	36.4
Mann E 0836	Internal Combustion	110	9,194	37.1
Mann E 2876	Internal Combustion	170	9,004	37.9

The conversion rates for the engine-generator were plotted vs. engine-generator size in Figure 7.

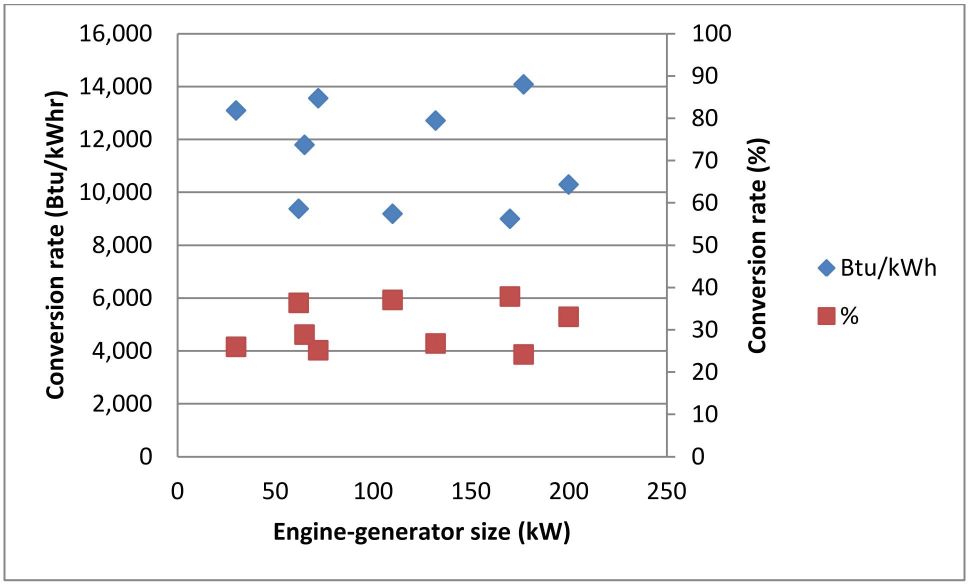

Figure 7. Energy conversion rate as a function of engine-generator size.

Because of the variability of conversion rates and to simplify calculations, an energy conversion rate of 11,460 Btu/kW (29.8 %) was used (the average of the nine examined engine-generators).

A capacity factor of 0.90 was used to adjust the power output of the engine-generator to account for engine-generator downtime, and variation in biogas output resulting in the engine-generator operating at less than 100% capacity.

5.1.5 Electricity consumption

To estimate the amount of electricity available for sale to the grid, it is first necessary to estimate the energy usage by the farm. To do so, data from energy audits of 50 farms in New York State milking fewer than 500 cows was obtained from Dick Peterson (2011). These audits contain the energy used over the course of the year, and the average number of cows milked. The mean number of cows milked on these 50 farms was 119, whereas the median was 76. The audits also break down the energy usage on farms by location/equipment type. The energy used vs. the number of cows milked was plotted and a linear relation was developed (Figure 8).

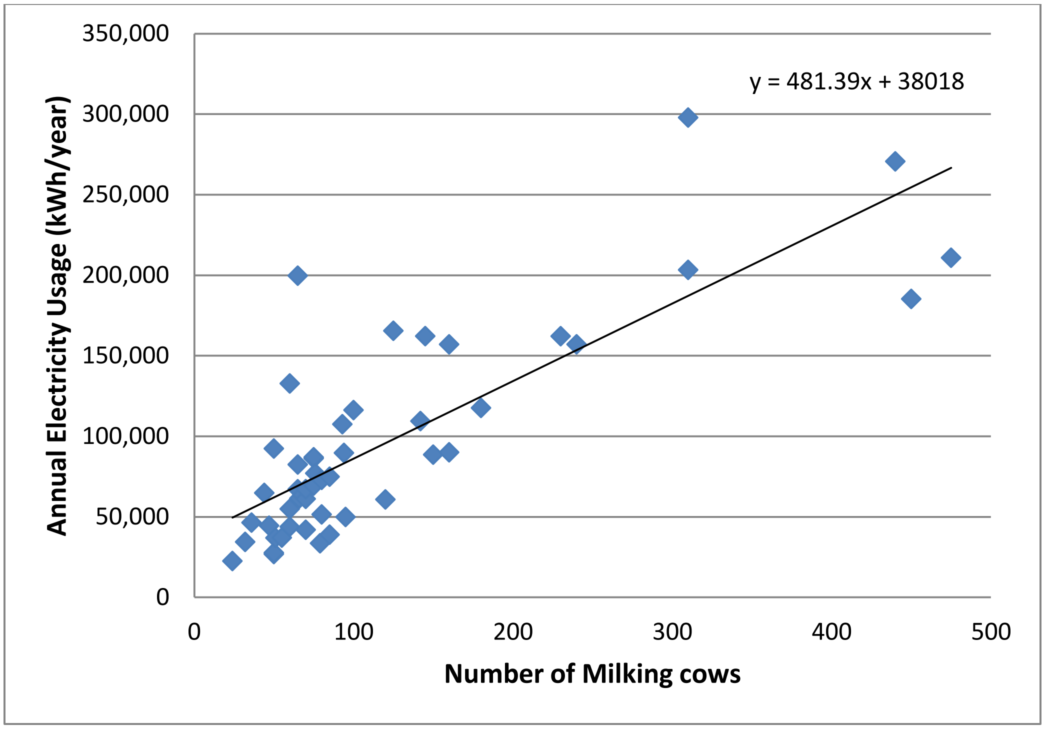

Figure 8. Annual electrical energy usage (kWh year^{-1}) as a function of the number of milking cows on 50 farms in New York State. Data was obtained from energy audits conducted by Dick Petersen (2011).

Using this relation the yearly electrical energy usage of the farm could be estimated based on knowing the number of milking (lactating) cows.

The electrical energy required to operate the digester (parasitic energy) was assumed to be 10% of the engine-generator production. This electricity is used to power mixers, pumps, blowers, etc., and is necessary to ensure the digester operates correctly. Parasitic loads such as this can vary from 5 up to 20% of produced electricity (Saville et al., 2008), depending on the type of digester used.

Subtracting the farm energy consumption and parasitic loads from the energy produced by the engine-generator returned the net electricity available for sale to the grid (calculations were done on a yearly basis).

5.2 Economic model

The economic model is concerned with the economic costs and benefits of the system. Capital and maintenance costs were estimated based on the sizes and quantities from the developed system model. Economic benefits such as avoided power purchases, surplus electricity sales, carbon credits and tipping fees were determined in a similar fashion. The assumptions necessary to perform these calculations are discussed in the following sections.

5.2.1 Capital cost assumptions

For the purposes of this analysis different capital cost scenarios were investigated (capital costs expressed on a per cow basis). The per cow cost is assumed to be the per lactating cow equivalent cost; i.e. the number of equivalent milking cows for which the system needs to treat manure.

The capital costs considered were:

- engine-generator
- digester vessel
- equipment associated with the digester (pumps, mixers, and blowers)
- manure effluent storage
- co-digestion substrate storage

A relation between the capital costs of small farm systems and farm size was not developed for this analysis because of the lack of adequate real world small farm examples from which to develop a function. In addition, the majority of small farm systems in the U.S. are no longer operational.

<u>Engine-generator</u>

For the analysis it was assumed that the installed cost of the engine-generator, the building to house it and the electrical switching gear associated with it was $1,000 per kW of engine capacity, which is an approximate rule of thumb (Weeks, 2012.) The engine-generators were assumed to have a useful life of 7 years, with a salvage value of 10%, and to depreciate linearly. The lost opportunity cost was assumed to be 5%.

Digester vessel

The capital cost of the digester vessel was derived from the per cow overall capital costs used in the analysis. The total project cost was calculated by multiplying the per cow cost by the number of cows. From this value the cost of the engine-generator (and any co-digestion substrate storage) was subtracted, with the digester vessel representing 90% of the balance and the equipment associated with the digester the remaining 10% of the balance. The digester vessel was assumed to have a useful life of 20 years, depreciate linearly and have no salvage value. The lost opportunity cost was assumed to be 5%.

Digester equipment

The equipment associated with the digester; pumps, mixers and blowers have a shorter lifespan than the digester vessel itself and so were treated separately for the purposes of this analysis. This equipment was assumed to have an expected useful life of 7 years, to depreciate linearly and to retain 10% of its value as salvage. The lost opportunity cost was assumed to be 5%.

Manure storage

One aspect of the analysis was to include (and not include) the cost of digester effluent storage. To qualify for carbon credits a pre-digester project, manure storage system is necessary; however, many small farms do not have long-term manure storage. The storage was assumed to be earthen lined embankment construction and the capital cost of storage was estimated from data provided by USDA-NRCS (Peter Wright, 2012). Costs for a small, medium, and large storage were plotted and an exponential relation fit (Figure 9).

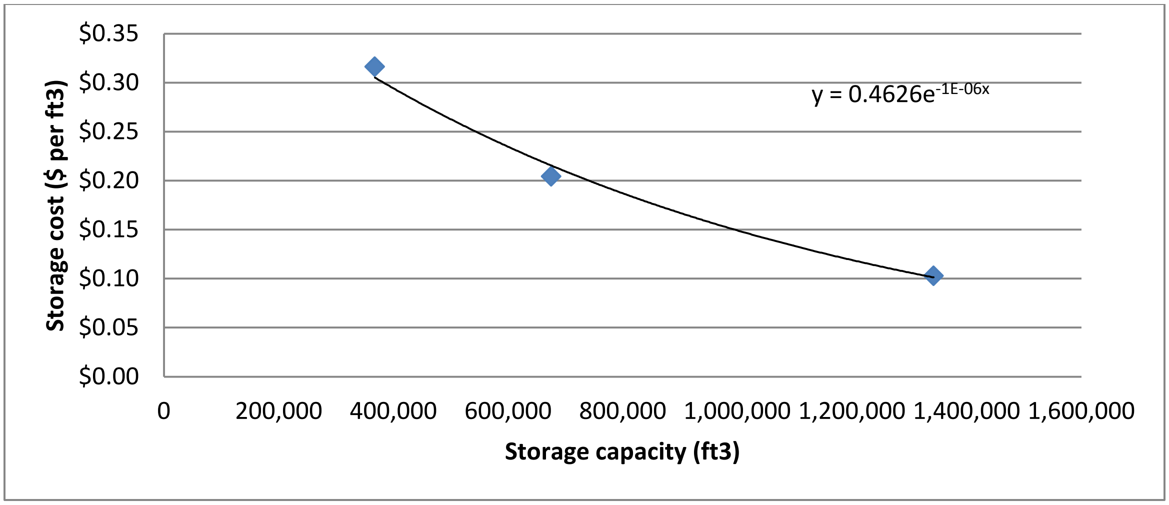

Figure 9. Lined earthen embankment manure storage costs as a function of storage capacity.

A function was developed relating the cost of construction to the volume of storage.

$$Cost = 0.4626e^{-1E-06*Vol}$$

Where: Cost is the cost of construction, ($ ft^{-3} storage)

Vol is the volume of storage, (ft^3)

Capacity of the earthen storage system was assumed to be up to 9 months of storage of the combination of effluent from the digester (including manure and any co-digestion volume). The storage capacities used to develop the cost relation already take into account precipitation plus 1.0 ft of freeboard.

The earthen storage systems were assumed to have a useful life of 15 years, to depreciate linearly and to have no salvage value. The lost opportunity cost was assumed to be 5%.

<u>Co-digestion storage</u>

To ensure regular feeding of the digester with co-digestion substrates, 4 days worth of material was assumed to be stored on-site. Material was assumed to be stored in a concrete tank with construction/installation costs of $1.04 per gallon of storage capacity. The co-digestion material storage system was assumed to have a useful life of 15 years, to depreciate linearly and to have no salvage value. The lost opportunity cost was assumed to be 5%.

5.2.2 Maintenance assumptions

Maintenance costs were estimated based both on the quantity of power generated, as well as a fixed percentage of the initial capital cost. For the purposes of this analysis it was assumed that no gas clean-up equipment was installed to reduce the concentration of H_2S in the biogas. High concentrations of H_2S shorten the lifespan of biogas equipment and as such the maintenance costs are higher. Maintenance costs are reported to be in the range of $0.015 to 0.020 per kWh generated (Marcus Martin personal communication in Gooch and Pronto, 2009). Assuming no gas cleanup, $0.02 per kWh was used. These values are conservative, as many of the labor costs associated with maintenance of engine-generators remain the same regardless of size.

General maintenance on the digester pumps/mixers and other equipment was estimated as 5% of the initial capital cost per year.

5.2.3 Tipping fee assumptions

Tipping fee revenues were estimated by multiplying the volume of material co-digested by the net tipping fee collected per volume (e.g. $0.05 per gallon). The net tipping fee represents the tipping fee the farmer charges less their added costs of spreading the additional liquid volume. The cost of storing raw and co-digested material is included in the capital costs of the system. A range of values were examined.

5.2.4 Carbon credit sale assumptions

The amount of carbon credits available was estimated using the MS Excel® workbook developed by the Climate Action Reserve (2008). The data required for the workbook used assumed values for NY, for farms with existing manure storage and the same assumed herd information used to estimate biogas production. Default values for lactating, heifer and dry cows were taken from the provided table information, along with the performance of the biogas containment system. The results of this worksheet provided the yearly avoided CO_2e in metric tons.

5.2.5 Electricity sale assumptions

A range of electricity prices and sale scenarios were investigated. For simple surplus electricity sales, the difference between the produced electricity and the electricity used on-farm (for general and digester operation) was multiplied by the sale price. The benefit of avoided purchased power was determined by multiplying the farm general operation electricity usage by the avoided purchase price. Energy used to operate the digester was excluded from the benefits as this is energy usage that would not be present without a digester. It was also assumed that farms were not subject to demand charges.

6.0 Economic analyses

These analyses were focused on small farms and determining what level of benefit pricing would allow them to cover the substantial capital cost investment. To answer this question, a total annual cost/benefit economic analysis was performed. The sum of the annual total costs to own and operate the system was subtracted from the cost savings and revenue, expressed on an annual basis. For this analysis, a negative value means that the system is a net economic liability to own and operate, while a positive value means that the system probably is an economic benefit, but further analysis would be needed to determine its true economic benefit to the farm. Another way to view negative values is that they represent the cost of non-monetized benefits such as odor control. By modeling the costs and benefits of a system on a per cow basis it becomes possible to solve for required herd sizes to offset the costs with the benefits. Additionally the model was used to investigate what effects incentives such as feed-in tariff rates, carbon credits, and tipping fees could have on the financial viability of a digester system. By varying these benefit prices in a number of combinations it is possible to see how important they are relative to one another.

A number of different scenarios were considered with the model.

- Scenario 1: The capital cost of the system was fixed at a constant per cow value. Two levels of cost were examined representing average and higher per cow costs. Under these levels of capital expenses, varying benefit prices of carbon credits, surplus power and tipping fees were examined.
- Scenario 2: The power pricing was adjusted so that a feed-in tariff pricing model was used, rather than net metering, such as is currently found in NYS.
- Scenario 3: The additional capital costs for long-term effluent storage was examined. This set of scenarios is more representative of the expenses small farms with no existing manure storage would face. Under these scenarios Carbon credits were not considered.
- Scenario 4: The benefits pricing necessary to offset the costs for a system sized at the national average farm size (153 milking cows) and average values for other factors was determined. Also examined was the effect of grant funding on the cost/benefit results.

- <u>Scenario 5:</u> The model was used to determine the minimum herd size necessary to provide enough biogas to supply a 20-kW engine-generator, with varying levels of co-digestion.

The upper limit of the farm size considered in this analysis was set at 500 cows. The lower limit was set by determining the minimum herd size necessary to power a 10-kW biogas engine-generator. Though no purpose built biogas engine-generator of this size was found during our analysis, it is possible that existing engine-generator designs for use with natural gas or propane could be modified to work with biogas (though they would likely require considerably more maintenance). The minimum herd size was set at 76 LCE_{VS} basis (56 milking cows) for the case of no co-digestion, 69 LCE_{VS} basis (51 milking cows) with 10% of the VS coming from co-digestion), and 61 LCE_{VS} basis (45 milking cows) with 25% of the VS from co-digestion.

6.1 Scenario 1: net metering

In Scenario 1, the benefits pricing of surplus power price, carbon credits and tipping fees were varied. In addition two levels of per cow capital costs were investigated.

The range of electricity price analyzed in these scenarios ranged from a basic wholesale price of $0.05 per kWh, to the feed-in tariff rates seen in Europe at $0.31 per kWh. An intermediate value of $0.16 (as available in Vermont) was also analyzed. A further important consideration is the purchase price of electricity. Avoided purchased power is an important benefit in engine-generator economics. To simplify the analysis, an avoided purchase price of $0.10 per kWh was used for all scenarios. A net metering situation was assumed such that power available for the grid was the total power generated, minus that required for on-farm (and digester) use, on an annual basis. The benefit of electricity generation was then assumed to be the avoided cost of purchased power, plus the sale of any surplus power.

Carbon prices have been depressed lately following the closure of the Chicago Climate Exchange, however this situation could change once the economic crisis resolves and/or the new Californian initiative begins. For this analysis, carbon credit pricing of $0 (no carbon credit value) to $20 with an intermediate value of $10 per metric ton CO_2e were investigated.

For co-digestion, net tipping fees for cheese whey were assumed to have a value of $0.05 (a typical price currently received) or $0.10 per gallon (a higher than average price). Additional scenarios assumed no net tipping fee for the co-digestate to evaluate the effect of increased biogas alone on the economics. Two levels of co-digestion were examined; a lower level where 10% of the VS are from co-digestion and a higher level where 25% are from co-digestion (the condition of no co-digestion was also examined).

The per cow capital costs examined in this series of scenarios were $1,500 and $3,000 per cow. $1,500 per cow represents a low cost for a small farm digester with an engine-generator. A higher value is $3,000 per cow for small farm systems with an engine-generator. These system cost levels were based on reviewing the project costs of the limited number of small farm digesters both with and without cogeneration of power, and were selected to span the likely average capital cost of a small farm AD project. The 63 combinations of benefit pricing values for each initial capital cost level were input into the model, and the number of cows necessary to offset the costs from the benefits was solved for (complete results in Appendix A). For this analysis a positive value indicates the system is likely an economic benefit to the farm and these combinations are presented in Table 5 and Table 6.) All values are expressed on a per cow basis.

Table 5. Annual cost/benefit analysis of benefit pricing scenarios resulting in a net benefit with an initial capital cost of $3,000 per cow.

Combination Surplus power price ($/kWh), CC price ($/tonne), %VS co-digested, and TF ($/gallon)	**Number Cows** (LCEvs)	**Annual Costs** ($/cow)				**Annual Benefits** ($/cow)					**Net** ($/cow)
		Capital	Maint	PP*	Total	Electricity avoided	Electricity sold	CC*	TF*	Total	
0.05, 0, 25, 0.10	61	262	143	14	420	118		0	321	439	19
0.16, 0, 25, 0.10	61	262	143	14	420	118		0	321	439	19
0.31, 0, 25S, 0.10	61	262	143	14	420	118		0	321	439	19
0.05, 10, 25, 0.10	61	262	143	14	420	118		32	321	470	50
0.16, 10, 25, 0.10	61	262	143	14	420	118		32	321	470	50
0.31, 10, 25, 0.10	61	262	143	14	420	118		32	321	470	50
0.05, 20, 25, 0.10	61	262	143	14	420	118		63	321	502	82
0.16, 20, 25, 0.10	61	262	143	14	420	118		63	321	502	82
0.31, 20, 25, 0.10	61	262	143	14	420	118		63	321	502	82
0.31, 20, 25, 0.05	500	262	146		407	78	125	63	160	426	19

*** PP = Purchased Power, CC = Carbon Credit, TF = Tipping Fee**

Table 6. Annual Cost/Benefit analysis of Benefit Pricing Scenarios Resulting in a Net Benefit with an Initial Capital Cost of $1,500 per cow.

Combination	Number Cows	Annual Costs				Annual Benefits					Net
Surplus power price ($/kWh), CC price ($/tonne), %VS co-digested, and TF ($/gallon)	(LCEvs)	($/cow)				($/cow)					($/cow)
						Electricity					
		Capital	Maint	PP*	Total	avoided	sold	CC	TF*	Total	
0.05, 0, 10, 0.10	69	136	75	21	232	104		0	129	233	1
0.16, 0, 10, 0.10	69	136	75	21	232	104		0	129	233	1
0.31, 0, 10, 0.10	69	136	75	21	232	104		0	129	233	1
0.05, 10 , 10, 0.10	69	136	75	21	232	104		32	129	264	32
0.16, 10, 10, 0.10	69	136	75	21	232	104		32	129	264	32
0.31, 10, 10, 0.10	69	136	75	21	232	104		32	129	264	32
0.05, 20, 10,$0.10	69	136	75	21	232	104		63	129	296	64
0.16, 20C, 10, 0.10	69	136	75	21	232	104		63	129	296	64
0.31, 20C, 10, 0.10	69	136	75	21	232	104		63	129	296	64
0.05, 0, 25, 0.10	69	137	76	7	221	118		0	321	440	219
0.16, 0, 25, 0.10	69	137	76	7	221	118		0	321	440	219
0.31, 0, 25S, 0.10	69	137	76	7	221	118		0	321	440	219
0.05, 10, 25, 0.10	69	137	76	7	221	118		32	321	471	250
0.16, 10, 25, 0.10	69	137	76	7	221	118		32	321	471	250
0.31, 10, 25, 0.10	69	137	76	7	221	118		32	321	471	250
0.05, 20, 25, 0.10	69	137	76	7	221	118		63	321	503	282
0.16, 20, 25, 0.10	69	137	76	7	221	118		63	321	503	282
0.31, 20, 25, 0.10	69	137	76	7	221	118		63	321	503	282
0.31, 0, 10, 0.05	311	135	77		213	82	67	0	64	213	0
0.16, 10, 10, 0.05	341	135	78		213	81	36	32	64	213	0
0.31, 10, 10, 0.05	137	136	77		212	98	19	32	64	212	0
0.05, 20, 10, 0.05	69	136	75	21	232	104		63	64	232	0
0.05, 0, 25, 0.05	61	138	76	14	227	118		0	160	278	51
0.16, 0, 25, 0.05	61	138	76	14	227	118		0	160	278	51
0.31, 0, 25, 0.05	61	138	76	14	227	118		0	160	278	51
0.05, 10, 25, 0.05	61	138	76	14	227	118		32	160	310	82
0.16, 10, 25, 0.05	61	138	76	14	227	118		32	160	310	82
0.31, 10, 25, 0.05	61	138	76	14	227	118		32	160	310	82
0.05, 20, 25, 0.05	61	138	76	14	227	118		63	160	341	114
0.16, 20, 25, 0.05	61	138	76	14	227	118		63	160	341	114
0.31, 20, 25, 0.05	61	138	76	14	227	118		63	160	341	114
0.31, 20, 10, 0	323	135	77		213	82	68	63	0	213	0
0.31, 10, 25, 0	232	137	78		215	86	97	31	0	215	0
0.31, 20, 25, 0	120	137	78		215	102	50	63	0	215	0

*** PP = Purchased Power, CC = Carbon Credit, TF = Tipping Fee**

For the case of a capital cost of $3,000 per cow, 10 combinations out of 63 resulted in benefits that offset capital and maintenance costs (and any purchased power costs). Under 9 of the combinations, even the lower limit farm size of 61 LCE_{vs} cows was capable of offsetting the costs.

At a per cow capital cost of $3,000 it is clear that co-digestion, coupled with a premium price for surplus power plays an important part of offsetting the capital costs. Only scenarios that featured a net tipping fee of $0.10 per gallon coupled with maximum co-digestion showed a neutral or net benefit. Carbon credit pricing helped somewhat, though at the highest level of electricity pricing and co-digestion it was not necessary to break even at the smallest farm size considered.

Clearly maximizing the tipping fee, and volume of co-digested substrate is essential for feasibility at a capital cost of $3,000 per cow.

The situation is quite different when the capital cost per cow is $1,500. Thirty-four of the 63 scenarios are neutral or show a potential benefit. Co-digestion is still a requirement, though scenarios with only 10% of the VS from co-digestion and/or lower/no net tipping fees are also feasible possibilities.

Low (and high) power sale price scenarios with other benefits often broke even at the lowest farm size, but this is due to the fact that at this farm size there is little or no surplus power to sell and so the sale price does not significantly come into play. The avoided cost of purchased power is however a major advantage, indicating that small farms would benefit most from sizing an engine-generator to meet their net on farm needs, rather than aiming to sell power to the grid.

Another clear result from this analysis is the importance of capital cost. The cost of carrying a large initial capital investment is a significant challenge, particularly with a small farm system.

6.2 Scenario 2: feed-in tariff

For this scenario similar combinations of benefits pricing as were examined in the previous section were repeated, however a true feed-in tariff pricing model was used. Under this model of electricity pricing, all power produced is sold to the grid at a premium rate, and all power used on-farm is purchased from the grid at market prices (including power needed to operate the digester). Power purchased to operate the digester was included in this analysis to facilitate making comparisons between net metering and feed-in tariff pricing, and it represents a cost the farm would have to bear to realize the benefits of a digester.

Feed-in tariff values of 16 and 31 cents per kWh were examined with purchased power assumed to cost 10 cents per kWh. As before two levels of capital costs ($1,500 and $3,000 per cow) were examined. The results of the 42 combinations for each capital cost can be found in Appendix B, and the combinations resulting in a neutral or net benefit to the farm are presented in Table 7 and Table 8.

Table 7. Annual Cost/Benefit analysis of Benefit Pricing Scenarios Resulting in a Net Benefit with an Initial Capital Cost of $3,000 per cow under a feed-in tariff structure.

Combination	Number Cows	Annual Costs				Annual Benefits				Net
Surplus power price ($/kWh), CC price ($/tonne), %VS co-digested, and TF ($/gallon)	(LCEvs)	($/cow)				($/cow)				($/cow)
		Capital	Maint	PP*	Total	FIT*	CC*	TF*	Total	
0.31, 0, 10, 0.10	352	260	145	81	486	358	0	128	486	0
0.31, 10, 10, 0.10	88	260	143	113	517	357	31	128	517	0
0.31, 20C, 10, 0.10	69	261	142	126	529	359	63	129	551	22
0.16, 0, 25, 0.10	69	262	144	126	532	211	0	321	532	0
0.31, 0, 25S, 0.10	69	262	144	126	532	408	0	321	729	198
0.16, 10, 25, 0.10	69	262	144	126	532	211	32	321	563	32
0.31, 10, 25, 0.10	69	262	144	126	532	408	32	321	761	229
0.16, 20, 25, 0.10	69	262	144	126	532	211	63	321	595	64
0.31, 20, 25, 0.10	69	262	144	126	532	408	63	321	793	261
0.31, 20, 10, 0.05	385	260	145	80	485	358	63	64	485	0
0.31, 0, 25, 0.05	61	262	143	133	538	407	0	160	567	29
0.31, 10, 25, 0.05	61	262	143	133	538	407	32	160	599	61
0.31, 20, 25, 0.05	61	262	143	133	538	407	63	160	630	92

***FIT = Feed-in tariff, PP = Purchased power cost, CC = Carbon Credit, TF = Tipping Fee**

Table 8. Annual Cost/Benefit analysis of Benefit Pricing Scenarios Resulting in a Net Benefit with an Initial Capital Cost of $1,500 per cow under a feed-in tariff Structure.

Combination Surplus power price ($/kWh), CC price ($/tonne), %VS co-digested, and TF ($/gallon)	Number Cows (LCEvs)	Annual Costs ($/cow)				Annual Benefits ($/cow)				Net ($/cow)
		Capital	Maint	PP*	Total	FIT*	CC*	TF*	Total	
0.31, 0, 0, 0	88	134	77	113	325	325	0	0	325	0
0.31, 10, 0, 0	76	134	77	120	332	326	32	0	357	25
0.31, 20, 0, 0	76	134	77	120	332	326	63	0	389	57
0.16, 0, 10, 0.10	124	136	76	101	313	185	0	128	313	0
0.31, 0, 10, 0.10	69	136	75	126	336	359	0	129	487	151
0.16, 10, 10, 0.10	69	136	75	126	336	185	32	129	345	9
0.31, 10, 10, 0.10	69	136	75	126	336	359	32	129	519	183
0.16, 20C, 10, 0.10	69	136	75	126	336	185	63	129	377	41
0.31, 20C, 10, 0.10	69	136	75	126	336	359	63	129	551	214
0.16, 0, 25, 0.10	61	138	76	133	346	210	0	321	530	185
0.31, 0, 25S, 0.10	61	138	76	133	346	407	0	321	727	381
0.16, 10, 25, 0.10	61	138	76	133	346	210	32	321	562	216
0.31, 10, 25, 0.10	61	138	76	133	346	407	32	321	759	413
0.16, 20, 25, 0.10	61	138	76	133	346	210	63	321	594	248
0.31, 20, 25, 0.10	61	138	76	133	346	407	63	321	790	445
0.31, 0, 10, 0.05	69	136	75	126	336	359	0	64	423	87
0.31, 10, 10, 0.05	69	136	75	126	336	359	32	64	455	118
0.16, 20, 10, 0.05	128	136	76	100	312	185	63	64	312	0
0.31, 20, 10, 0.05	69	136	75	126	336	359	63	64	486	150
0.16, 0, 25, 0.05	61	138	76	133	346	210	0	160	370	24
0.31, 0, 25, 0.05	61	138	76	133	346	407	0	160	567	221
0.16, 10, 25, 0.05	61	138	76	133	346	210	32	160	402	56
0.31, 10, 25, 0.05	61	138	76	133	346	407	32	160	599	253
0.16, 20, 25, 0.05	61	138	76	133	346	210	63	160	433	87
0.31, 20, 25, 0.05	61	138	76	133	346	407	63	160	630	284
0.31, 0, 10, 0	69	136	75	126	336	359	0	0	359	22
0.31, 10, 10, 0	69	136	75	126	336	359	32	0	391	54
0.31, 20, 10, 0	69	136	75	126	336	359	63	0	422	86
0.31, 0, 25, 0	61	138	76	133	346	407	0	0	407	61
0.31, 10, 25, 0	61	138	76	133	346	407	32	0	438	92
0.31, 20, 25, 0	61	138	76	133	346	407	63	0	470	124

***FIT = Feed-in tariff, PP = Purchased power cost, CC = Carbon Credit, TF = Tipping Fee**

Thirteen of 42 scenarios with a capital cost of $3,000 per cow proved to be neutral or positive. Again, at this capital level, maximizing the revenue from co-digestion tipping fees (and increased biogas/electricity production) were essential to breaking even. Carbon credit pricing did not appear to contribute significantly to the net benefits.

For the case of a capital expense of $1,500 per cow, 31 of 42 combinations resulted in a neutral or net benefit to the farm. Indeed, all of the combinations with a feed-in tariff rate of $0.31/kWh appear feasible; even the combination with no co-digestion and no carbon credit benefits. And 10 of the 21 combinations with $0.16/kWh pricing were also feasible.

A feed-in tariff pricing model that places a premium value on the power produced appears to increase the conditions under which a digester can be profitable, particularly when coupled with co-digestion.

6.3 Scenario 3: additional capital expense for storage

In this next scenario, additional capital expenses for long-term storage of effluent were added. Traditionally, smaller farms do not have such long-term storage systems in place and when considering a digester, would need to take this additional expense into account. For these scenarios carbon credit benefit pricing was excluded, as typically a farm must have some sort of long-term manure storage system in place to demonstrate a reduction in methane release.

For these analyses carbon credits were not considered. The combinations with positive or neutral net values are presented in Table 9 and Table 10, the complete results for all 21 combinations for each capital cost level are presented in Appendix C.

Table 9. Annual Cost/Benefit analysis of Benefit Pricing Scenarios with an Initial Capital Cost of $3,000 per cow plus additional capital costs for long term effluent storage.

Combination	**Number Cows**	**Annual Costs**					**Annual Benefits**				**Net**
Surplus power price ($/kWh), %VS co-digested, and TF ($/gallon)	(LCEvs)	($/cow)					($/cow)				($/cow)
		Capital	Maint	Store	PP	Total	Electricity Avoided	Sold	TF**	Total	
0.16, 25, 0.10	100	262	145	40		446	108	16	322	446	0
0.31h, 25, 0.10	87	262	144	40		446	114	13	320	446	0

***Store = Storage costs, TF = Tipping Fee, PP = Purchased Power**

Table 10. Annual Cost/Benefit analysis of Benefit Pricing Scenarios with an Initial Capital Cost of $1,500 per cow plus additional capital costs for long term effluent storage.

Combination Surplus power price ($/kWh), %VS co-digested, and TF ($/gallon)	Number Cows (LCEvs)	Annual Costs ($/cow) Capital	Maint	Store	PP	Total	Annual Benefits ($/cow) Electricity Avoided	Sold	TF	Total	Net ($/cow)
0.16, 10, 0.10	233	136	77	30		243	86	28	128	243	0
0.31, 10, 0.10	136	136	77	33		245	98	18	128	245	0
0.05, 25, 0.10	61	138	76	41	14	255	118		321	439	170
0.16, 25, 0.10	61	138	76	41	14	255	118		321	439	170
0.31h, 25, 0.10	61	138	76	41	14	255	118		321	439	170
0.05, 25, 0.05	61	138	76	41	14	255	118		160	278	9
0.16, 25, 0.05	61	138	76	41	14	255	118		160	278	9
0.31, 25, 0.05	61	138	76	41	14	255	118		160	278	9

***Store = Storage costs, TF = Tipping Fee, PP = Purchased Power**

As in the case of the analyses without additional long-term capital costs for storage, no combination of benefits pricing without co-digestion showed a neutral or net positive benefit to the farm at either capital cost levels.

The installation of lined earthen storage added an additional yearly per cow cost of $21.83 for a farm size of 500 LCE_{vs} (with no co-digestion), and $41.19 for a farm size of 61 LCE_{vs} (with 25% co-digestion).

At a capital cost of $3,000 per cow for the digester and engine-generator, only the two combinations of maximum co-digestion and highest net tipping fee and electricity rates of $0.16, and $0.31 per kWh sold, provided a net benefit to the farm. At this level of capital cost it is clear that without outside assistance, farm based AD projects of this small size are unlikely to be feasible.

At a capital cost of $1,500 per cow for the digester and engine-generator only eight combinations with the highest level of co-digestion (25% VS from co-digestion) and two scenarios with mid level co-digestion demonstrated the potential to be feasible. At the highest level of co-digestion and some net tipping fee, even the case with a low value for surplus power was feasible.

6.4 Scenario 4: estimation of required benefits pricing for the U.S. average herd size

In this scenario, the model was run with a fixed farm size, to examine what levels of benefit pricing and capital costs result in feasible projects. The farm size chosen was 153 cows (207 LCE_{vs}) which represents the average herd size for the U.S. in 2010 (USDA, 2011). For these three analyses, the model with additional capital costs for long-term manure storage was used, and carbon credit benefits were not included.

Baseline pricing for surplus power was assumed to be \$0.05 per kWh (net metering model) and the avoided power price was assumed to be \$0.10 per kWh. Co-digestion was examined at three levels (0%, 10% and 25% VS basis) and a baseline net tipping fee of \$0.05 per gallon was used. A baseline capital cost of \$2,700 per cow was used. This value is based on averaging the 2012 adjusted capital costs for three existing small farm anaerobic digesters with associated engine-generator (Klavon, 2011).

6.4.1 Varying electricity pricing

The pricing of surplus power was adjusted to balance the yearly costs with the benefits for a fixed farm size of 153 milking cows. Seven combinations of co-digestion ratios and tipping fee prices were examined and the results presented in Table 11.

Table 11: Power price required for benefits to balance costs with fixed herd size and capital costs, varying co-digestion rates and tipping fees.

Combination	**Number Cows**	**Annual Costs**			**Annual Benefits**				**Net**	**Minimum Electricity Price**
%VS co-digested, and TF (\$/gallon)	(LCEvs)	(\$/cow)			(\$/cow)				(\$/cow)	(\$/kWh)
		Capital	Maint	Total	Electricity Avoided	Electricity Sold	TF*	Total		
0, 0	207	234	131	365	88	277	0	365	0	4.66
10, 0.10	207	235	131	366	88	150	128	366	0	0.98
10, 0.05	207	235	131	366	88	214	64	366	0	1.39
10, 0	207	235	131	366	88	278	0	366	0	1.81
25, 0.10	207	237	132	369	88	0	320	408	39	0.00
25, 0.05	207	237	132	369	88	121	160	369	0	0.41
25, 0	207	237	132	369	88	280	0	369	0	0.95

***TF = Tipping Fee**

At a farm size of 153 milking cows, the required premiums for surplus power are significant. With no co-digestion at all, a farmer would have to receive $4.66 per kWh for their project to be feasible. Co-digestion not only increases the amount of electricity produced, but the tipping fee is a critical benefit to offset the capital expense. With 25% of the VS coming from co-digestion and a net tipping fee of $0.10 per gallon, an operation does not require the sale of surplus power to be possibly economically feasible.

6.4.2 Varying tipping fees

Six combinations of co-digestion amounts (10% or 25% of the VS from co-digestion) and surplus power prices ($0.05, $0.16, and $0.31 per kWh) the net tipping fees required to balance costs with benefits were determined and presented in Table 12.

Table 12: Net tipping fee required for benefits to balance costs with fixed herd size and capital costs and varying co-digestion rate and electricity price.

Combination	**Number Cows**	**Annual Costs**			**Annual Benefits**				**Net**	**Minimum Net Tipping Fee**
Surplus power price ($/kWh), %VS co-digested	(LCEvs)	($/cow)			($/cow)				($/cow)	($/gallon)
					Electricity					
		Capital	Maint	Total	Avoided	Sold	TF*	Total		
0.05, 10	207	235	131	366	88	8	270	366	0	0.21
0.16, 10	207	235	131	366	88	25	253	366	0	0.20
0.31, 10	207	235	131	366	88	48	230	366	0	0.18
0.05, 25	207	237	132	369	88	15	266	369	0	0.08
0.16, 25	207	237	132	369	88	47	233	369	0	0.07
0.31, 25	207	237	132	369	88	92	189	369	0	0.06

***TF = Tipping Fee**

In the previous analyses co-digestion has been important in making AD feasible. The results presented in Table 12 also show that increasing the amount of co-digestion reduces the net tipping fee required to balance the costs with the benefits.

Increasing the total volume of material processed allows the tipping fees to be that much lower. This is illustrated by comparing the results for the case of surplus power sold at $0.05 per kWh. With 10% of the VS from co-digestion the income from tipping fees is $270 per cow and the required net tipping fee per gallon is $0.21. With 25% of the VS from co-digestion the income from tipping fees is a similar $266 per cow and the required net tipping fee per gallon is

$0.08. The net tipping fee of $0.21 per gallon is 2.6 times greater than the net tipping fee of $0.08 when 2.5 times more material is co-digested. These numbers differ more when there is a premium paid for surplus power (2.9 and 3 times greater for prices of $0.16 and $0.31 per kWh), but the major difference is due to the volume of material co-digested. This implies that once the system is in place it pays to maximize the amount of material co-digested, and allows a lower tipping fee to be collected.

6.4.3 Varying capital costs

Combinations of benefit pricing were run through the model with the farm size set at 153 milking cows, and the required capital cost for the benefits to match the costs was determined and presented in Table 13.

Table 13: Capital cost required for benefits to balance costs with fixed herd size and capital costs and varying co-digestion rate and electricity price.

Combination	Number Cows	Annual Costs			Annual Benefits				Net	Maximum Allowable Capital Cost
Surplus power price ($/kWh), %VS co-digested, and TF ($/gallon)	(LCEvs)	($/cow)			($/cow)				($/cow)	($/cow)
		Capital	Maint	Total	Electricity Avoided	Sold	TF	Total		
0.05, 0, 0	207	56	35	91	88	3	0	91	0	561
0.16, 0, 0	207	61	37	98	88	10	0	98	0	612
0.31, 0, 0	207	66	40	107	88	18	0	107	0	682
0.05, 10, 0.10	207	143	81	224	88	8	128	224	0	1,589
0.16, 10, 0.10	207	154	87	241	88	25	128	241	0	1,721
0.31, 10, 0.10	207	169	95	264	88	48	128	264	0	1,901
0.05, 25, 0.10	207	272	151	423	88	15	320	423	0	3,123
0.16, 25, 0.10	207	293	162	456	88	47	320	456	0	3,376
0.31, 25, 0.10	207	322	178	500	88	92	320	500	0	3,722
0.05, 10, 0.05	207	101	59	160	88	8	64	160	0	1,089
0.16, 10, 0.05	207	112	65	177	88	25	64	177	0	1,222
0.31, 10, 0.05	207	127	73	200	88	48	64	200	0	1,402
0.05, 25, 0.05	207	168	95	263	88	15	160	263	0	1,874
0.16, 25, 0.05	207	189	106	296	88	47	160	296	0	2,128
0.31, 25, 0.05	207	218	122	340	88	92	160	340	0	2,474
0.05, 10, 0	207	60	36	96	88	8	0	96	0	590
0.16, 10, 0	207	71	42	113	88	25	0	113	0	722
0.31, 10, 0	207	86	50	136	88	48	0	136	0	902
0.05, 25, 0	207	64	39	103	88	15	0	103	0	626
0.16, 25, 0	207	86	50	136	88	47	0	136	0	879
0.31, 25, 0	207	114	66	180	88	92	0	180	0	1,225

Of the 21 combinations examined, nine had a balancing capital cost greater than $1,500 per cow, and three greater than $2,700 per cow. The remaining scenarios required that the capital cost per cow be below $2,500 per cow, with the lowest requiring that the capital expense be no more than $561 per cow when no co-digestion is used and surplus power is sold for $0.05 per kWh.

It is unlikely that such low capital cost levels can be achieved through improved technology, designs or manufacturing, however the cost borne by the farmer could approach these levels if part of the capital cost is offset by a development grant.

6.4.4 Grant funding level

Grant programs to reduce the burden and risk to small (and large) farms are one means that has been used to increase the number of on farm anaerobic digesters. The effect of grant support on the annual cost/benefit, for a 153 cow dairy is presented in Table 14. The capital costs for a 153 cow dairy (153 cows represents the approximate average size herd in the U.S. in 2011) were estimated by averaging the capital costs for three existing small farm anaerobic digesters with associated engine-generator (Klavon 2011). The percentage of the total capital cost of $2,700 per cow paid by the farm was then varied from 100% down to 10% and the annual cost/benefit calculated. Benefits assumed surplus power was sold at the purchase rate of $0.10 per kWh, no carbon credit revenues, and net tipping fees of $0.05 per gallon for cheese whey making up 10% of the volatile solids digested. Additional capital expenses for long term effluent/manure storage were included in the analysis, but were not included as a percentage of the capital cost aided by the grant. Results are presented in Table 14.

The calculations show that with a grant covering 50% of the digester and engine-generator capital costs, the project is probably an economic benefit. A 50% grant on a total capital cost of $2,700 per cow and 153 cows, is approximately $279,000.

Table 14. Annual Cost/Benefit Analysis of the Effect of % Grant Support with Benefit Values of $0.10 per kWh for power, $0 per tonne Carbon Credit, and Co-Digestion with 10% of the VS from off-farm cheese whey and a net tipping fee of $0.05 per gallon, for a 153 cow dairy farm with a Capital Cost of $2,700 per cow (plus additional capital cost for long term effluent storage).

Capital Cost % Borne by Farm	Cow # (LCEvs)	Annual Costs ($/cow)		Annual Benefits ($/cow)			Total Annual Cost/ Benefit
		Capital	Maint	Electricity Avoided cost	Electricity Sold	TF	
100% ($2,700 per cow)	207	$235	$131	$88	$48	$64	($166)
90% ($2,430 per cow)	207	$213	$119	$88	$48	$64	($132)
80% ($2,160 per cow)	207	$190	$107	$88	$48	$64	($97)
70% ($1,890 per cow)	207	$168	$95	$88	$48	$64	($63)
60% ($1,620 per cow)	207	$146	$82	$88	$48	$64	($28)
50% ($1,350 per cow)	207	$123	$70	$88	$48	$64	$7
40% ($1,080 per cow)	207	$101	$58	$88	$48	$64	$41
30% ($810 per cow)	207	$78	$46	$88	$48	$64	$76
28% ($753 per cow)	207	$73	$43	$88	$48	$64	$83
20% ($540 per cow)	207	$56	$34	$88	$48	$64	$110
10% ($270 per cow)	207	$33	$22	$88	$48	$64	$145

6.5 Scenario 5: minimum herd size to supply the smallest available engine-generator

In producing electricity from manure, the selection of an engine-generator is a critical consideration. Often operations are plagued with premature failure of the engine-generator, and high maintenance cost/requirements. This is because biogas as it comes off the digester contains contaminants such as H_2S which are highly corrosive. To alleviate this problem, many operations employ scrubbing systems to purify the biogas coming off the digester. However these systems are expensive and can require considerable maintenance themselves.

For reliable operation it is important to go with an engine-generator that is designed to run on biogas. There are several manufacturers available, however many companies only focus on large scale operations; much too large for a small farm to supply with biogas. As a starting point for deciding on whether anaerobic digestion for electricity production is a viable option for a farm, the smallest commercially available engine-generator was selected, and then it was determined how many animals would be required to generate enough biogas to keep the engine-generator steadily running.

The smallest commercial engine-generator used for this analysis was a 20-kW internal combustion unit IPOWER Energy Systems, LLC, currently used by Avatar Energy on their small modular AD projects. Their ENI 20 unit has a stated net heat rate of 12,185 BTU kWh^{-1} when run on digester gas. This corresponds to a biogas feed rate of 243,700 BTU h^{-1}. Because biogas is a mixture of CH_4, CO_2 and H_2S, the feed rate was adjusted to take into account the lower CH_4 content. A CH_4 content of 0.6 was assumed for the biogas, and that methane has an energy content of 896 BTU ft^{3-1}. This corresponds to a biogas feed rate of 10,879 ft^3 day^{-1} to keep the 20-kW engine-generator running at full capacity.

Dividing the biogas feed rate for the engine-generator by the biogas production rate yields the herd size necessary to supply the engine-generator. For a 20-kW engine-generator with only manure as the feedstock this corresponds to a herd of 118 milking cows (159 LCE_{vs}). Manure and whey digested at a 75:25 VS basis, corresponds to 95 (128 LCE_{vs}) milking cows and 90:10 VS basis to 108 milking cows (146 LCE_{vs}).

A 20-kW engine-generator would typically produce about 166,440 kWh $year^{-1}$, assuming a 95% capacity factor. For a farm with a milking herd size of 118 cows, the estimated yearly power usage is 149,700 kWh $year^{-1}$. Ninety-five cows is 128,000 kWh $year^{-1}$ and 108 cows is 140,100 kWh $year^{-1}$. Operating a 20-kW engine-generator could result in a deficit of power production of approximately 284 kWh $year^{-1}$ for the case of no co-digestion to a surplus of approximately 22,500 kWh $year^{-1}$ when co-digesting at a 75:25 VS basis.

7.0 Economic analysis discussion

It is clear from the results of the analyses that financing small farm AD can be difficult depending on the incentive programs available to a farmer. Even with relatively generous incentive programs of surplus electricity sales, carbon credits and feed-in tariff, it may take several benefit programs in concert to justify AD at the small farm level and typically only with some level of co-digestion and tipping fee. Avoided costs of purchasing power are a significant benefit, and the sale of surplus power even with a generous premium price may not be worth it.

Electricity sales alone are not likely to support AD either for large or particularly small farms. Though feed-in tariff models increase the number of scenarios under which the cost/benefit indicates a positive economic benefit.

Co-digestion has great potential to increase revenues through increased electricity production and particularly tipping fees, however there are associated negatives. First, it is likely very difficult to guarantee both a long-term price and source for co-digestible organics. As more farms turn to co-digestion to supplement their income from their digesters it may become even more difficult to source. A second difficulty with co-digestion is guaranteeing the quality of the co-digestate to ensure proper and optimal operation of the digester. When co-digesting high levels of organics other than manure, systems are more prone to expensive failures. To ensure a digester operates efficiently with high levels of co-digestion requires increased labor to properly monitor the system and its inputs. A small farm may find it difficult to find enough time to dedicate to the digester.

An important consideration when planning to use off-farm organics in a digester is the nutrients in the material. If a farm is limited in size, land applying all of the effluent may exceed the values in the farms Comprehensive Nutrient Management Plan. Additionally increased volume from food waste corresponds to an increase of the size of digester, and effluent storage and an increase in the costs to spread the effluent.

The initial capital cost of digester systems is a major hurdle to their further adoption and strategic policy will need to be enacted to allow small farms to participate in AD. Keeping the capital costs to the farm below $1,500 per cow whether through grant programs or improved low cost designs would likely be preferable to relying on feed-in tariff and carbon credit programs where the benefit pricing may be variable or short lived. Small scale moveable digesters present an exciting means of reducing the hurdle of the cost of lost capital. Being moveable allows the system to be treated and financed like any other piece of farm equipment. Modular systems can also be scalable, allowing a farm to change their treatment capacity as needed.

A key economic consideration is whether small farms will still be around/viable in the 20 year payback period assumed for digester systems. The trend in dairy production is in decreasing farm numbers and increasing sizes as small farms go out of business. There is also the possibility that implementing policy to encourage AD, could actually drive smaller farms out of business as larger farms move to take advantage of AD incentives and become more competitive.

Another consideration when deciding on whether to pursue AD on a small farm, is the valuation of non-monetary benefits such as improved flexibility in field application and odor reduction. These can be very significant reasons for installing an AD system particularly if a small farm is located near encroaching residential areas. The net cost of an AD system could be a means of assigning value to odor reduction.

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Appendices

Appendix A: Analysis Scenarios 1. Variable Benefit and Cost pricing: Net Metering

Annual cost/benefit analysis of benefit pricing scenarios resulting in a net benefit with an initial capital cost of $3,000 per cow.

Scenario	Cow # (LCEvs)	Annual Costs ($/cow)		Annual Benefits ($/cow)				
				Electricity				
		Capital	Maint	avoided	net	CC*	TF**	net
$0.05/kWh, no CC, no CD	500	$259	$145	$78	$8	$0	$0	($318)
$0.16/kWh, no CC, no CD	500	$259	$145	$78	$27	$0	$0	($299)
$0.31/kWh, no CC, no CD	500	$259	$145	$78	$52	$0	$0	($274)
$0.05/kWh, $10 CC, no CD	500	$259	$145	$78	$8	$32	$0	($286)
$0.16/kWh, $10 CC, no CD	500	$259	$145	$78	$27	$32	$0	($268)
$0.31/kWh, $10 CC, no CD	500	$259	$145	$78	$52	$32	$0	($243)
$0.05/kWh, $20 CC, no CD	500	$259	$145	$78	$8	$63	$0	($255)
$0.16/kWh, $20 CC, no CD	500	$259	$145	$78	$27	$63	$0	($236)
$0.31/kWh, $20 CC, no CD	500	$259	$145	$78	$52	$63	$0	($211)
$0.05/kWh, no CC, 10% VS, $0.10 TF	500	$260	$145	$78	$13	$0	$128	($186)
$0.16/kWh, no CC, 10% VS, $0.10 TF	500	$260	$145	$78	$42	$0	$128	($157)
$0.31/kWh, no CC, 10% VS, $0.10 TF	500	$260	$145	$78	$81	$0	$128	($118)
$0.05/kWh, $10 CC, 10% VS, $0.10 TF	500	$260	$145	$78	$13	$32	$128	($155)
$0.16/kWh, $10 CC, 10% VS, $0.10 TF	500	$260	$145	$78	$42	$32	$128	($126)
$0.31/kWh, $10 CC, 10% VS, $0.10 TF	500	$260	$145	$78	$81	$32	$128	($87)
$0.05/kWh, $20 CC, 10% VS, $0.10 TF	500	$260	$145	$78	$13	$63	$128	($123)
$0.16/kWh, $20 CC, 10% VS, $0.10 TF	500	$260	$145	$78	$42	$63	$128	($94)
$0.31/kWh, $20 CC, 10% VS, $0.10 TF	500	$260	$145	$78	$81	$63	$128	($55)
$0.05/kWh, no CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$0	$321	$19
$0.16/kWh, no CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$0	$321	$19
$0.31/kWh, no CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$0	$321	$19
$0.05/kWh, $10 CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$32	$321	$50
$0.16/kWh, $10 CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$32	$321	$50
$0.31/kWh, $10 CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$32	$321	$50
$0.05/kWh, $20 CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$63	$321	$82
$0.16/kWh, $20 CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$63	$321	$82
$0.31/kWh, $20 CC, 25% VS, $0.10 TF	61	$262	$143	$118	($14)	$63	$321	$82
$0.05/kWh, no CC, 10% VS, $0.05 TF	500	$260	$145	$78	$13	$0	$64	($250)
$0.16/kWh, no CC, 10% VS, $0.05 TF	500	$260	$145	$78	$42	$0	$64	($221)
$0.31/kWh, no CC, 10% VS, $0.05 TF	500	$260	$145	$78	$81	$0	$64	($182)
$0.05/kWh, $10 CC, 10% VS, $0.05 TF	500	$260	$145	$78	$13	$32	$64	($219)
$0.16/kWh, $10 CC, 10% VS, $0.05 TF	500	$260	$145	$78	$42	$32	$64	($190)
$0.31/kWh, $10 CC, 10% VS, $0.05 TF	500	$260	$145	$78	$81	$32	$64	($151)
$0.05/kWh, $20 CC, 10% VS, $0.05 TF	500	$260	$145	$78	$13	$63	$64	($187)
$0.16/kWh, $20 CC, 10% VS, $0.05 TF	500	$260	$145	$78	$42	$63	$64	($158)
$0.31/kWh, $20 CC, 10% VS, $0.05 TF	500	$260	$145	$78	$81	$63	$64	($119)
$0.05/kWh, no CC, 25% VS, $0.05 TF	500	$262	$146	$78	$20	$0	$160	($149)

$0.16/kWh, no CC, 25% VS, $0.05 TF	500	$262	$146	$78	$65	$0	$160	($105)
$0.31/kWh, no CC, 25% VS, $0.05 TF	500	$262	$146	$78	$125	$0	$160	($44)
$0.05/kWh, $10 CC, 25% VS, $0.05 TF	500	$262	$146	$78	$20	$32	$160	($118)
$0.16/kWh, $10 CC, 25% VS, $0.05 TF	500	$262	$146	$78	$65	$32	$160	($73)
$0.31/kWh, $10 CC, 25% VS, $0.05 TF	500	$262	$146	$78	$125	$32	$160	($13)
$0.05/kWh, $20 CC, 25% VS, $0.05 TF	500	$262	$146	$78	$20	$63	$160	($86)
$0.16/kWh, $20 CC, 25% VS, $0.05 TF	500	$262	$146	$78	$65	$63	$160	($42)
$0.31/kWh, $20 CC, 25% VS, $0.05 TF	500	$262	$146	$78	$125	$63	$160	$19
$0.05/kWh, no CC, 10% VS, no TF	500	$260	$145	$78	$13	$0	$0	($314)
$0.16/kWh, no CC, 10% VS, no TF	500	$260	$145	$78	$42	$0	$0	($286)
$0.31/kWh, no CC, 10% VS, no TF	500	$260	$145	$78	$81	$0	$0	($246)
$0.05/kWh, $10 CC, 10% VS, no TF	500	$260	$145	$78	$13	$32	$0	($283)
$0.16/kWh, $10 CC, 10% VS, no TF	500	$260	$145	$78	$42	$32	$0	($254)
$0.31/kWh, $10 CC, 10% VS, no TF	500	$260	$145	$78	$81	$32	$0	($215)
$0.05/kWh, $20 CC, 10% VS, no TF	500	$260	$145	$78	$13	$63	$0	($251)
$0.16/kWh, $20 CC, 10% VS, no TF	500	$260	$145	$78	$42	$63	$0	($222)
$0.31/kWh, $20 CC, 10% VS, no TF	500	$260	$145	$78	$81	$63	$0	($183)
$0.05/kWh, no CC, 25% VS, no TF	500	$262	$146	$78	$20	$0	$0	($309)
$0.16/kWh, no CC, 25% VS, no TF	500	$262	$146	$78	$65	$0	$0	($265)
$0.31/kWh, no CC, 25% VS, no TF	500	$262	$146	$78	$125	$0	$0	($204)
$0.05/kWh, $10 CC, 25% VS, no TF	500	$262	$146	$78	$20	$32	$0	($278)
$0.16/kWh, $10 CC, 25% VS, no TF	500	$262	$146	$78	$65	$32	$0	($233)
$0.31/kWh, $10 CC, 25% VS, no TF	500	$262	$146	$78	$125	$32	$0	($173)
$0.05/kWh, $20 CC, 25% VS, no TF	500	$262	$146	$78	$20	$63	$0	($246)
$0.16/kWh, $20 CC, 25% VS, no TF	500	$262	$146	$78	$65	$63	$0	($202)
$0.31/kWh, $20 CC, 25% VS, no TF	500	$262	$146	$78	$125	$63	$0	($141)

Annual cost/benefit analysis of benefit pricing scenarios resulting in a net benefit with an initial capital cost of $1,500 per cow.

Scenario	Cow # (LCEvs)	Annual Costs ($/cow)		Annual Benefits ($/cow)				
				Electricity				
		Capital	Maint	avoided	net	CC	TF	net
$0.05/kWh, no CC, no CD	500	$134	$77	$78	$8	$0	$0	($125)
$0.16/kWh, no CC, no CD	500	$134	$77	$78	$27	$0	$0	($107)
$0.31/kWh, no CC, no CD	500	$134	$77	$78	$52	$0	$0	($82)
$0.05/kWh, $10 CC, no CD	500	$134	$77	$78	$8	$32	$0	($94)
$0.16/kWh, $10 CC, no CD	500	$134	$77	$78	$27	$32	$0	($76)
$0.31/kWh, $10 CC, no CD	500	$134	$77	$78	$52	$32	$0	($50)
$0.05/kWh, $20 CC, no CD	500	$134	$77	$78	$8	$63	$0	($62)
$0.16/kWh, $20 CC, no CD	500	$134	$77	$78	$27	$63	$0	($44)
$0.31/kWh, $20 CC, no CD	500	$134	$77	$78	$52	$63	$0	($19)
$0.05/kWh, no CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$0	$129	$1
$0.16/kWh, no CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$0	$129	$1
$0.31/kWh, no CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$0	$129	$1
$0.05/kWh, $10 CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$32	$129	$32
$0.16/kWh, $10 CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$32	$129	$32
$0.31/kWh, $10 CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$32	$129	$32

$0.05/kWh, $20 CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$63	$129	$64
$0.16/kWh, $20 CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$63	$129	$64
$0.31/kWh, $20 CC, 10% VS $0.10 TF	69	$136	$75	$104	($21)	$63	$129	$64
$0.05/kWh, no CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$0	$321	$219
$0.16/kWh, no CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$0	$321	$219
$0.31/kWh, no CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$0	$321	$219
$0.05/kWh, $10 CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$32	$321	$250
$0.16/kWh, $10 CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$32	$321	$250
$0.31/kWh, $10 CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$32	$321	$250
$0.05/kWh, $20 CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$63	$321	$282
$0.16/kWh, $20 CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$63	$321	$282
$0.31/kWh, $20 CC, 25% VS $0.10 TF	69	$137	$76	$118	($7)	$63	$321	$282
$0.05/kWh, no CC, 10% VS $0.05 TF	500	$135	$78	$78	$13	$0	$64	($58)
$0.16/kWh, no CC, 10% VS $0.05 TF	500	$135	$78	$78	$42	$0	$64	($29)
$0.31/kWh, no CC, 10% VS $0.05 TF	311	$135	$77	$82	$67	$0	$64	$0
$0.05/kWh, $10 CC, 10% VS $0.05 TF	500	$135	$78	$78	$13	$32	$64	($27)
$0.16/kWh, $10 CC, 10% VS $0.05 TF	341	$135	$78	$81	$36	$32	$64	$0
$0.31/kWh, $10 CC, 10% VS $0.05 TF	137	$136	$77	$98	$19	$32	$64	$0
$0.05/kWh, $20 CC, 10% VS $0.05 TF	69	$136	$75	$104	($21)	$63	$64	$0
$0.16/kWh, $20 CC, 10% VS $0.05 TF	69	$136	$75	$104	($21)	$63	$64	($0)
$0.31/kWh, $20 CC, 10% VS $0.05 TF	69	$136	$75	$104	($21)	$63	$64	($0)
$0.05/kWh, no CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$0	$160	$51
$0.16/kWh, no CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$0	$160	$51
$0.31/kWh, no CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$0	$160	$51
$0.05/kWh, $10 CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$32	$160	$82
$0.16/kWh, $10 CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$32	$160	$82
$0.31/kWh, $10 CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$32	$160	$82
$0.05/kWh, $20 CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$63	$160	$114
$0.16/kWh, $20 CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$63	$160	$114
$0.31/kWh, $20 CC, 25% VS $0.05 TF	61	$138	$76	$118	($14)	$63	$160	$114
$0.05/kWh, no CC, 10% VS no TF	500	$135	$78	$78	$13	$0	$0	($122)
$0.16/kWh, no CC, 10% VS no TF	500	$135	$78	$78	$42	$0	$0	($93)
$0.31/kWh, no CC, 10% VS no TF	500	$135	$78	$78	$81	$0	$0	($54)
$0.05/kWh, $10 CC, 10% VS no TF	500	$135	$78	$78	$13	$32	$0	($91)
$0.16/kWh, $10 CC, 10% VS no TF	500	$135	$78	$78	$42	$32	$0	($62)
$0.31/kWh, $10 CC, 10% VS no TF	500	$135	$78	$78	$81	$32	$0	($23)
$0.05/kWh, $20 CC, 10% VS no TF	500	$135	$78	$78	$13	$63	$0	($59)
$0.16/kWh, $20 CC, 10% VS no TF	500	$135	$78	$78	$42	$63	$0	($30)
$0.31/kWh, $20 CC, 10% VS no TF	323	$135	$77	$82	$68	$63	$0	$0
$0.05/kWh, no CC, 25% VS no TF	500	$137	$78	$78	$20	$0	$0	($117)
$0.16/kWh, no CC, 25% VS no TF	500	$137	$78	$78	$65	$0	$0	($73)
$0.31/kWh, no CC, 25% VS no TF	500	$137	$78	$78	$125	$0	$0	($12)
$0.05/kWh, $10 CC, 25% VS no TF	500	$137	$78	$78	$20	$32	$0	($86)
$0.16/kWh, $10 CC, 25% VS no TF	500	$137	$78	$78	$65	$32	$0	($41)
$0.31/kWh, $10 CC, 25% VS no TF	232	$137	$78	$86	$97	$31	$0	$0
$0.05/kWh, $20 CC, 25% VS no TF	500	$137	$78	$78	$20	$63	$0	($54)
$0.16/kWh, $20 CC, 25% VS no TF	500	$137	$78	$78	$65	$63	$0	($10)
$0.31/kWh, $20 CC, 25% VS no TF	120	$137	$78	$102	$50	$63	$0	$0

Appendix B: Analysis Scenarios 2. Variable Benefit and Cost pricing: Feed-in Tariff

Annual Cost/Benefit analysis of Benefit Pricing Scenarios Resulting in a Net Benefit with an Initial Capital Cost of $3,000 per cow under a feed-in tariff Structure.

Scenario	Cow # (LCEvs)	Annual Costs ($/cow)			Annual Benefits ($/cow)			
		Capital	Maint	Power	FIT	CC*	TF**	net
$0.16/kWh, no CC, no CD	500	$259	$145	$78	$168	$0	$0	($314)
$0.31/kWh, no CC, no CD	500	$259	$145	$78	$326	$0	$0	($156)
$0.16/kWh, $10 CC, no CD	500	$259	$145	$78	$168	$32	$0	($282)
$0.31/kWh, $10 CC, no CD	500	$259	$145	$78	$326	$32	$0	($125)
$0.16/kWh, $20 CC, no CD	500	$259	$145	$78	$168	$63	$0	($251)
$0.31/kWh, $20 CC, no CD	500	$259	$145	$78	$326	$63	$0	($93)
$0.16/kWh, no CC, 10% VS $0.10 TF	500	$260	$145	$78	$185	$0	$128	($170)
$0.31/kWh, no CC, 10% VS $0.10 TF	352	$260	$145	$81	$358	$0	$128	$0
$0.16/kWh, $10 CC, 10% VS $0.10 TF	500	$260	$145	$78	$185	$32	$128	($138)
$0.31/kWh, $10 CC, 10% VS $0.10 TF	88	$260	$143	$113	$357	$31	$128	$0
$0.16/kWh, $20 CC, 10% VS $0.10 TF	500	$260	$145	$78	$185	$63	$128	($107)
$0.31/kWh, $20 CC, 10% VS $0.10 TF	69	$261	$142	$126	$359	$63	$129	$22
$0.16/kWh, no CC, 25% VS $0.10 TF	69	$262	$144	$126	$211	$0	$321	$0
$0.31/kWh, no CC, 25% VS $0.10 TF	69	$262	$144	$126	$408	$0	$321	$198
$0.16/kWh, $10 CC, 25% VS $0.10 TF	69	$262	$144	$126	$211	$32	$321	$32
$0.31/kWh, $10 CC, 25% VS $0.10 TF	69	$262	$144	$126	$408	$32	$321	$229
$0.16/kWh, $20 CC, 25% VS $0.10 TF	69	$262	$144	$126	$211	$63	$321	$64
$0.31/kWh, $20 CC, 25% VS $0.10 TF	69	$262	$144	$126	$408	$63	$321	$261
$0.16/kWh, no CC, 10% VS $0.05 TF	500	$260	$145	$78	$185	$0	$64	($234)
$0.31/kWh, no CC, 10% VS $0.05 TF	500	$260	$145	$78	$358	$0	$64	($61)
$0.16/kWh, $10 CC, 10% VS $0.05 TF	500	$260	$145	$78	$185	$32	$64	($203)
$0.31/kWh, $10 CC, 10% VS $0.05 TF	500	$260	$145	$78	$358	$32	$64	($29)
$0.16/kWh, $20 CC, 10% VS $0.05 TF	500	$260	$145	$78	$185	$63	$64	($171)
$0.31/kWh, $20 CC, 10% VS $0.05 TF	385	$260	$145	$80	$358	$63	$64	$0
$0.16/kWh, no CC, 25% VS $0.05 TF	500	$262	$146	$78	$210	$0	$160	($115)
$0.31/kWh, no CC, 25% VS $0.05 TF	61	$262	$143	$133	$407	$0	$160	$29
$0.16/kWh, $10 CC, 25% VS $0.05 TF	500	$262	$146	$78	$210	$32	$160	($83)
$0.31/kWh, $10 CC, 25% VS $0.05 TF	61	$262	$143	$133	$407	$32	$160	$61
$0.16/kWh, $20 CC, 25% VS $0.05 TF	500	$262	$146	$78	$210	$63	$160	($52)
$0.31/kWh, $20 CC, 25% VS $0.05 TF	61	$262	$143	$133	$407	$63	$160	$92
$0.16/kWh, no CC, 10% VS no TF	500	$260	$145	$78	$185	$0	$0	($298)
$0.31/kWh, no CC, 10% VS no TF	500	$260	$145	$78	$358	$0	$0	($125)
$0.16/kWh, $10 CC, 10% VS no TF	500	$260	$145	$78	$185	$32	$0	($267)
$0.31/kWh, $10 CC, 10% VS no TF	500	$260	$145	$78	$358	$32	$0	($93)
$0.16/kWh, $20 CC, 10% VS no TF	500	$260	$145	$78	$185	$63	$0	($235)
$0.31/kWh, $20 CC, 10% VS no TF	500	$260	$145	$78	$358	$63	$0	($62)
$0.16/kWh, no CC, 25% VS no TF	500	$262	$146	$78	$210	$0	$0	($275)
$0.31/kWh, no CC, 25% VS no TF	500	$262	$146	$78	$407	$0	$0	($78)
$0.16/kWh, $10 CC, 25% VS no TF	500	$262	$146	$78	$210	$32	$0	($244)
$0.31/kWh, $10 CC, 25% VS no TF	500	$262	$146	$78	$407	$32	$0	($47)
$0.16/kWh, $20 CC, 25% VS no TF	500	$262	$146	$78	$210	$63	$0	($212)
$0.31/kWh, $20 CC, 25% VS no TF	500	$262	$146	$78	$407	$63	$0	($15)

Annual Cost/Benefit analysis of Benefit Pricing Scenarios Resulting in a Net Benefit with an Initial Capital Cost of $1,500 per cow under a feed-in tariff Structure.

Scenario	Cow # (LCEvs)	Annual Costs ($/cow)			Annual Benefits ($/cow)			
		Capital	Maint	Power	FIT	CC	TF	net
$0.16/kWh, no CC, no CD	500	$134	$77	$78	$168	$0	$0	($121)
$0.31/kWh, no CC, no CD	88	$134	$77	$113	$325	$0	$0	$0
$0.16/kWh, $10 CC, no CD	500	$134	$77	$78	$168	$32	$0	($90)
$0.31/kWh, $10 CC, no CD	76	$134	$77	$120	$326	$32	$0	$25
$0.16/kWh, $20 CC, no CD	500	$134	$77	$78	$168	$63	$0	($58)
$0.31/kWh, $20 CC, no CD	76	$134	$77	$120	$326	$63	$0	$57
$0.16/kWh, no CC, 10% VS $0.10 TF	124	$136	$76	$101	$185	$0	$128	$0
$0.31/kWh, no CC, 10% VS $0.10 TF	69	$136	$75	$126	$359	$0	$129	$151
$0.16/kWh, $10 CC, 10% VS $0.10 TF	69	$136	$75	$126	$185	$32	$129	$9
$0.31/kWh, $10 CC, 10% VS $0.10 TF	69	$136	$75	$126	$359	$32	$129	$183
$0.16/kWh, $20 CC, 10% VS $0.10 TF	69	$136	$75	$126	$185	$63	$129	$41
$0.31/kWh, $20 CC, 10% VS $0.10 TF	69	$136	$75	$126	$359	$63	$129	$214
$0.16/kWh, no CC, 25% VS $0.10 TF	61	$138	$76	$133	$210	$0	$321	$185
$0.31/kWh, no CC, 25% VS $0.10 TF	61	$138	$76	$133	$407	$0	$321	$381
$0.16/kWh, $10 CC, 25% VS $0.10 TF	61	$138	$76	$133	$210	$32	$321	$216
$0.31/kWh, $10 CC, 25% VS $0.10 TF	61	$138	$76	$133	$407	$32	$321	$413
$0.16/kWh, $20 CC, 25% VS $0.10 TF	61	$138	$76	$133	$210	$63	$321	$248
$0.31/kWh, $20 CC, 25% VS $0.10 TF	61	$138	$76	$133	$407	$63	$321	$445
$0.16/kWh, no CC, 10% VS $0.05 TF	500	$135	$78	$78	$185	$0	$64	($42)
$0.31/kWh, no CC, 10% VS $0.05 TF	69	$136	$75	$126	$359	$0	$64	$87
$0.16/kWh, $10 CC, 10% VS $0.05 TF	500	$135	$78	$78	$185	$32	$64	($10)
$0.31/kWh, $10 CC, 10% VS $0.05 TF	69	$136	$75	$126	$359	$32	$64	$118
$0.16/kWh, $20 CC, 10% VS $0.05 TF	128	$136	$76	$100	$185	$63	$64	$0
$0.31/kWh, $20 CC, 10% VS $0.05 TF	69	$136	$75	$126	$359	$63	$64	$150
$0.16/kWh, no CC, 25% VS $0.05 TF	61	$138	$76	$133	$210	$0	$160	$24
$0.31/kWh, no CC, 25% VS $0.05 TF	61	$138	$76	$133	$407	$0	$160	$221
$0.16/kWh, $10 CC, 25% VS $0.05 TF	61	$138	$76	$133	$210	$32	$160	$56
$0.31/kWh, $10 CC, 25% VS $0.05 TF	61	$138	$76	$133	$407	$32	$160	$253
$0.16/kWh, $20 CC, 25% VS $0.05 TF	61	$138	$76	$133	$210	$63	$160	$87
$0.31/kWh, $20 CC, 25% VS $0.05 TF	61	$138	$76	$133	$407	$63	$160	$284
$0.16/kWh, no CC, 10% VS no TF	500	$135	$78	$78	$185	$0	$0	($106)
$0.31/kWh, no CC, 10% VS no TF	69	$136	$75	$126	$359	$0	$0	$22
$0.16/kWh, $10 CC, 10% VS no TF	500	$135	$78	$78	$185	$32	$0	($74)
$0.31/kWh, $10 CC, 10% VS no TF	69	$136	$75	$126	$359	$32	$0	$54
$0.16/kWh, $20 CC, 10% VS no TF	500	$135	$78	$78	$185	$63	$0	($43)
$0.31/kWh, $20 CC, 10% VS no TF	69	$136	$75	$126	$359	$63	$0	$86
$0.16/kWh, no CC, 25% VS no TF	500	$137	$78	$78	$210	$63	$0	($20)
$0.31/kWh, no CC, 25% VS no TF	61	$138	$76	$133	$407	$0	$0	$61
$0.16/kWh, $10 CC, 25% VS no TF	500	$137	$78	$78	$210	$32	$0	($51)
$0.31/kWh, $10 CC, 25% VS no TF	61	$138	$76	$133	$407	$32	$0	$92
$0.16/kWh, $20 CC, 25% VS no TF	500	$137	$78	$78	$210	$63	$0	($20)
$0.31/kWh, $20 CC, 25% VS no TF	61	$138	$76	$133	$407	$63	$0	$124