



AGRICULTURAL BIOGAS IN THE UNITED STATES

A Market Assessment

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Field Project Team #6

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May 2011

Acknowledgements

This report was completed by a team of seven first-year graduate students in the two-year master's program at the Tufts University Department of Urban and Environmental Policy and Planning (UEP), with the assistance and support of Meister Consultants Group, Inc., a private energy consultancy based in Boston, Mass. We are especially grateful to Neil Veilleux and Hilary Flynn for the time and input they dedicated to helping guide our progress. The experiences that they shared with us regarding how to approach our interviews with both government regulators and with farmers was invaluable, and this project could not have been a success without them. We owe a huge debt of gratitude to all of the individuals who we interviewed for this report, of which there are too many to name here. We could not have done our work without their willingness to tell us their stories, and share with us the details of their experience with developing agricultural biogas facilities. Their thoughtful input is the foundation of this report. Finally, we are deeply appreciative to our Tufts University instruction team: Professors Rachel G. Bratt and Robert H. Russell, and Teaching Assistants Pete Kane and Jay Monty. Their thoughtful wisdom, input, and guidance made this report possible.

Abstract

This project takes an in depth look at the development process for agriculturally-based anaerobic digestion facilities nationally and in four states in order to determine barriers to market entry for farms that could harness this technology to produce energy. The bulk of this report focuses on the regulatory process, financial incentives, and other market factors at work federally, and in Vermont, California, New York, and Massachusetts to determine the typical development journey for agricultural anaerobic digestion in these states. Substantial research into the permitting and utility interconnection process was done to determine the required permits and necessary procedures in these states for these facilities to comply with federal, state, and local regulations. Research was also conducted into the financial incentives available in these states and federal to encourage development of these projects. Key stakeholders were then interviewed to determine how this theoretical process is translated into everyday practice. The results of this combined research effort show that Vermont is currently the model state of agriculturally-based anaerobic digestion development. Recommendations are provided to assist other states to develop a similar system, as well as to improve upon Vermont's model. The findings of this project should be relevant to Meister Consultants Group as they try to assist clients to develop these facilities, but also for any other person involved in the development of an agricultural biogas facility who needs guidance on navigating the process.

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Executive Summary

The production of farm-based biogas in the United States is presently miniscule in comparison to the maximum production potential of farms with the adequate farm type and size. This is true even in spite of the energy and environmental benefits that agricultural biogas can bring to this nation. This report seeks to determine why the agricultural biogas market has not taken off in the United States like it has abroad. In-depth analyses of the technology, regulatory, and market-based aspects of the current biogas industry was conducted, with a focus on Vermont, California, New York, and Massachusetts as well as the federal government. This research was supplemented by extensive interviews with farmers, key stakeholders, lenders, and consultants with experience with agricultural biogas development in the 4 focus states.

This study of the current state of the U.S. industry allows us to understand the most common barriers to entering the market, and make recommendations to create a more inviting process, as to ultimately expand this minimally-tapped form of renewable energy production. Vermont, California, and New York were chosen because the farm-based biogas industries in those states are relatively advanced compared with the rest of the country. As a foil, we compare these states to Massachusetts, which has seen far less success in the development of these facilities.

The Introduction describes the scope of this research, and how it contributes to the overall understanding of the biogas industry. Vermont was chosen for a case study because it represents the most successfully functioning biogas industry in the country. Alternatively, Massachusetts demonstrates the opposite end of the spectrum because it has no currently operating agricultural biogas facilities; but is trying to establish them. California and New York were chosen to demonstrate state models that have been more successful at promoting farm-based biogas, but have not achieved the same success rates as Vermont.

Chapter 2 introduces the reader to the scientific and technical aspects of the biogas industry. After explaining how biogas is created through the process of anaerobic digestion, the primary technology options that farmers have when deciding to install anaerobic digesters on their farms are introduced and explained. Chapter 3 provides

the international context within which the United States is ultimately functioning. Biogas development has been far more successful in several other countries than it has in the United States. Brief glimpses into how three different biogas industries have evolved in Germany, China, and Brazil provide general understanding about the types of policies necessary to support the transition to producing energy through anaerobic digestion.

Then in Chapter 4 the current national landscape is explained. In addition to providing a comparison between the number of currently operating anaerobic digestion facilities in the United States, and the total national potential for these facilities, this chapter explains in broad strokes the types of permitting, and financial policies that a farmer will likely have to navigate when trying to develop such a facility in this country. There is also a description of the general market conditions and private funding opportunities that are currently used by the biogas industry.

Chapter 5 focuses on the specific permitting requirements, utility interconnection standards, and funding opportunities provided by the federal government. The Clean Water Act, Clean Air Act, and Federal Energy Regulatory Commission requirements are explained in reference to how they impact the development of a farm-based biogas system. Additionally, the primary funding mechanisms available from the federal government to incentivize this type of development are explained.

Chapters 6 through 9 each explain the results of the in depth case studies in Vermont, California, New York, and Massachusetts, respectively. Each chapter first explains the significant attributes of the market in the relevant state, followed by the permitting and utility interconnection requirements imposed by that state. Each chapter then discusses the costs associated with developing agricultural biogas in the state, and the most common methods of funding that development. Finally, each chapter concludes with a brief analysis of the unique challenges farmers trying to develop these projects faced in the given state, and current for future opportunities to continue or create a successful farm-based biogas industry.

In Chapter 10 the generic development process of any farmer seeking to develop a farm-based biogas project is outlined through the hypothetical journey of Nellie. Nellie, a New York based dairy farmer, decides to invest in an anaerobic digestion facility for her farm to alleviate several problems she is currently facing. The steps that Nellie must take to successfully accomplish this goal are broadly outlined, with the caveat that every development process is customized and unique to the individual farm.

The report concludes by synthesizing all of this information about the current international, national, and state-based biogas markets to provide some lessons and recommendations for future growth. In applying the lessons to be gleaned about what policies foster a successful biogas market from comparing the successful Vermont market, to the less successful states, certain conclusions can be drawn about policies and practices that should be implemented to encourage overall farm-based biogas growth. Stable sources of funding and revenue need to be guaranteed by the government to compel farmers to invest in the expensive and risky technology. Technology and information should be made more readily available to farmers on farms that could possibly support the technology. Permitting requirements need to address anaerobic digestion specifically to avoid as much confusion as possible during the permitting process. Finally, research and innovation need to continue to improve the technology to make it less risky, and available for a broader scale of farms. In the end, it is clear that the biogas industry will not thrive in the United States without government policies specifically promoting its development, but there are many proven approaches that could greatly enhance the feasibility of developing a strong, national, farm-based biogas industry.

“Getting a methane digester has been a dream for more than ten years...Milk and power are both livelihoods for us. I want to do it all and I’ll just keep cows as a hobby.”

- Randy Jordan, Owner, Jordan Dairy Farm

Chapter 1

Introduction

1 Introduction

As the debates over energy access, cost, security, and environmental impact continue to escalate in the American discourse, increasing attention has been paid to the potential of biofuels. In speeches in February 2010 and April 2011, President Barack Obama emphasized the particular significance of including biofuels in a comprehensive strategy to replace oil usage and diminish dependence on all fossil fuels. Biofuels encompass many different types of energy generation, from ethanol to biomass to agricultural biogas. This report focuses on the latter.

Though relatively well developed in other countries, the farm-based biogas production industry in the United States has yet to come close to realizing its full potential. This report seeks to provide a greater understanding of the reasons why the agricultural biogas market has been so slow to develop in the United States, and to evaluate the strides forward, and steps backward, that

U.S. farms have experienced in their relatively nascent efforts to generate biogas. Because the international biogas market has already received in depth analysis from other authors, the scope of this report is focused on the U.S. market only. The Field Projects team (the Team) sought to provide a comprehensive understanding of the regulatory, market, and financing components that have and continue to influence agricultural biogas development. This report provides a window into the federal regulatory, market, and financing features that frame the development of biogas in the states and in-depth views into the functioning of the on-farm biogas market in the case study states of Vermont, California, New York, and Massachusetts. The report also includes a basic roadmap for a farm entering the market, recommendations to improve access to the market, and maps and charts that contextualize the discussion and elucidate the Team's findings.

“We’re going to use cleaner sources of energy that don’t imperil our climate. And we’re going to spark new products and businesses all over the country by tapping America’s greatest renewable resource: our ingenuity.”

- President Obama
Weekly Radio Address, April 1, 2011

1.1 Project Goals

The overriding goal of the project has been to explore challenges and identify regulatory and market barriers to the agricultural biogas development in the U.S. Under this umbrella, the Team has sought to determine and document the state of the current American agricultural biogas industry through the study of the country at large, international trends,

and, most specifically, the lens of the current market and regulatory climate in Vermont, California, New York, and Massachusetts.

Through the investigation and analysis of the market and regulations of these four states, the Team will strive to make recommendations that policymakers and farmers/producers could follow in order to eliminate or bypass those barriers. This report further aims to highlight lessons learned in order to recommend possible paths forward for greater agricultural biogas industry development in the U.S.

Neither an in-depth study of the international agricultural biogas market nor a review of other types of biogas development is included in this report. Moreover, a significant portion of the work performed focused on the collection, aggregation, and analysis of data from farms with existing operational anaerobic digesters (ADs)¹ from research and stakeholder interviews. This report, however, focuses on general findings, analysis, and lessons learned from this data, and the specific and detailed references to farms, data, or individuals are not incorporated.

1.2 Methodology and Process


In order to meet the project goals, the Field Project team divided its seven members into three distinct, though flexible, groups. Two members led the market study; two guided the regulatory research, and three delved into the majority of the background research while also assisting the other teams in particular research and data-gathering assignments and stakeholder interviews. The work of these latter three included reviewing current literature, drafting fact sheets (Appendix A), training the other team members in the nuances of biogas technology and composition, the general state of agricultural biogas in the U.S., and an international biogas overview paired with a focused look at Germany, China, and Brazil. These countries were selected because of the existence of a strong agricultural biogas industry in each, which manifests in different ways. Germany has long been considered a leader in the field; China has made great strides in more recent years, and Brazil's strong ethanol from sugarcane industry has encouraged other biofuel proliferation.

¹ Anaerobic digestion is the process by which biogas is produced, and the technology used to produce biogas is called an anaerobic digester. In depth explanation of this technology and process will follow in Chapter 2.

The background, technology, permitting, utility interconnection, and financing areas were comprehensively examined. They appear here in the report to provide a coherent and thorough context from which to understand the paths to market, the entry barriers, the market operations, and the reality on the ground for farmers, vendors, and policymakers in the four selected foci states. Neither the market research nor the data and anecdotal evidence collected from stakeholders would be meaningful without understanding the regulations, utility requirements, and funding hoops with which one is presented when developing an AD facility. All of these factors greatly affect the current market in each state.

Vermont, California, New York, and Massachusetts were chosen for study in this report for a number of reasons. The first three are among the states with the highest number of operational on-farm ADs in the country. Massachusetts provides a strong counterpoint, as it possesses zero operational digesters at present. It is further interesting and relevant not only because of its geographic proximity to the Field Project team, but also because its regulations do technically allow biogas development and because farms in Western Massachusetts are currently attempting to install an AD to produce biogas. This work in progress provides an intriguing look at a state in the process of launching an agricultural biogas industry and market. Vermont stands on the other end of the spectrum. It possesses one of the most advanced markets and has the regulatory and financing structures in place to justify this. California and New York lie between the two extremes, and demonstrate operational markets that have not yet been as successful as that in Vermont.

Rigorous research was thus undertaken among the entire team, and meetings were held often. Interviews were conducted with stakeholders, including farm owners, digester vendors, agency representatives, and consultants. The interviews sought to learn about the installation of the digester, its maintenance and operation, the intended end-use of the biogas, the composition of the material fed into the digester, the digester's financing, utility connection if electricity is produced, their experience with the permitting process, and the challenges inherent in and lessons learned from any or all of these factors. The interview guide is included in the Appendices as is a list of the AD projects in the case study states (Appendix B & C). Interviews were conducted over the phone, with email follow-up when necessary. Information was also gleaned from internet and journal research to fill in gaps for data that was not attained from interviews or to gain knowledge of the farms with which the Team was unable to communicate. The Team attempted to interview an individual at all of the farms with operational digesters, and achieved a 33% success rate. Analysis of the data and research provided the basis for the report's recommendations and conclusions.



The Institutional Review Board (IRB) granted this project exempt status. The IRB's official notification to the Team states that the project's research and methods do not qualify as human subject research (Appendix D). Additionally, the individual farmers and vendors' interview responses have been kept confidential.

Chapter 2

Background on Biogas

2 Background on Biogas

2.1 What is Biogas?

Biogas is produced from the anaerobic digestion (AD) of organic matter. It is typically made up of 50% to 80% methane, 20% to 50% carbon dioxide, and traces of hydrogen, carbon monoxide, and nitrogen (US Department of Energy, 2011). Biogas can be used for all applications designed for natural gas, can be combusted to produce heat and steam, and can also be used to generate electricity with an electrical efficiency up to 41% (International Energy Agency, 2005). The advancement of fuel cell technology, both bi-generation and tri-generation, can utilize biogas to produce heat and electricity at more than 60% efficiency (Persson & Jonsson, 2006). In addition, removing the water vapor and sulfide from biogas to utilize it as vehicle fuel is becoming more common in Europe. Biogas vehicles use the same engine and vehicle configuration as do natural gas vehicles. Finally, biogas can be integrated into the natural gas grid if the biogas is upgraded to increase the methane content to 97%.

2.2 History of Biogas

Evidence of biogas-use can be found in ancient civilizations. Anecdotal evidence indicates that biogas was used for heating bath water in Assyria during the 10th century BC. Marco Polo, in the 13th century AD, discovered people in China using covered sewage tanks to generate heat. In the 17th century, Jan Baptista Van Helmont determined that decaying organic matter produced flammable gas, which enabled Count Alessandro Volta to conclude that there was a direct correlation between the amount of decaying organic matter and the amount of flammable gas produced. Additionally, Sir Humphrey Davy discovered in 1808 that methane was present in the gases produced in cattle manure piles. In 1859, the first AD plant was built to process sewage in Bombay, India and the technology was transferred to United Kingdom, where gas from sewage was used to light street lamps across the city of Exeter. The use of farm manure for methane production was again developed in Bombay, India in the 1930s. By the 1970s, during the midst of two oil crises, biogas had attracted attention as a viable alternative source of energy. Numerous ADs were built in Europe, the United States, India, and China at this time, but due to a lack of technical understanding and overconfidence, the failure rate of these ADs was as high as 50%. Though investment in biogas technology waned in the 1980s as oil prices decreased, technological advances continued to create the current AD technology that, if designed and operated properly, generates biogas efficiently and without failure.

2.3 Biogas Benefits and Limitations

The benefits of biogas are diverse and multifaceted, and include, but are not limited to, the following. The biogas itself can be used on-site to offset energy costs. It can also be sold to utilities to promote a more resilient and diversified energy system composition. The digested effluent, including the treated organic matter, can be applied as fertilizer, reducing the use of artificial fertilizer and reducing costs. These materials can also be sold as a soil amendment. Biogas plants also serve as a method of waste and sewage disposal; thus directly improving user hygiene because pathogens are extensively eliminated during the digestion process. In addition, using biogas to produce energy can decrease the risks of global climate change. The reduction of one kilogram (kg) of methane is equivalent to the reduction of twenty-five kg of carbon dioxide in terms of global climate change reduction potential. In this vein, agricultural biogas is a potential source of renewable energy generation for regions of the country, like the southeast, that have limited ability to produce electricity from more developed technologies like wind or solar energy. Finally, pertaining to agricultural AD specifically, since the livestock manure generated at feedlots and dairies pose a risk of surface and ground water contamination from runoff, ADs further protect water bodies from nonpoint source pollution. The feedlots and dairies that use AD facilities are also healthier from a nutrient management and animal health perspective.

There are limitations associated with the use of farm-based biogas that need to be considered as well. The upfront capital investment on ADs is high. Although the life cycle benefits may exceed the initial cost, many medium- and small-scale farm owners cannot afford the initial investment without grants or private financing sources. Moreover, ADs require certain technical skills to operate and maintain, which many farmers do not have. Additionally, the current technology requires a certain, larger sized, farm in order to produce biogas in a usable quantity. Thus, many small-scale farms are not even large enough to take advantage of the technology on their own, and those that are on the margin cannot afford to pay for it. Moreover, ADs require certain technical skills to operate and maintain, which many farmers do not have. Finally, unlike wind or solar technology – for which the developer can choose the best location, ADs have to be located on or near the farm, which is stationary. Therefore, often the technology, and the energy produced by the technology are located far away from the electricity grid. If a farmer wants to create added revenue by selling electricity then the farmer also has to invest in extensions from the grid to the farm.

2.4 Biogas Technology

2.4.1 The Biochemical Process of Anaerobic Digestion

Anaerobic digestion is a series of processes in which anaerobic bacteria ferment biodegradable matter into biogas in the absence of oxygen. The basic processes involved in AD are hydrolysis, fermentation, acetogenesis, and methanogenesis (Figure 1). During hydrolysis, the insoluble complex organic matter, such as cellulose, proteins, and fats, are broken down by hydrolytic bacteria into soluble compounds. Next, acetogenic bacteria convert these soluble compounds into organic acid so that in the last stage, methanogenic bacteria can convert the organic acids into methane, carbon dioxide, and water, with traces of ammonia and hydrogen sulfide.

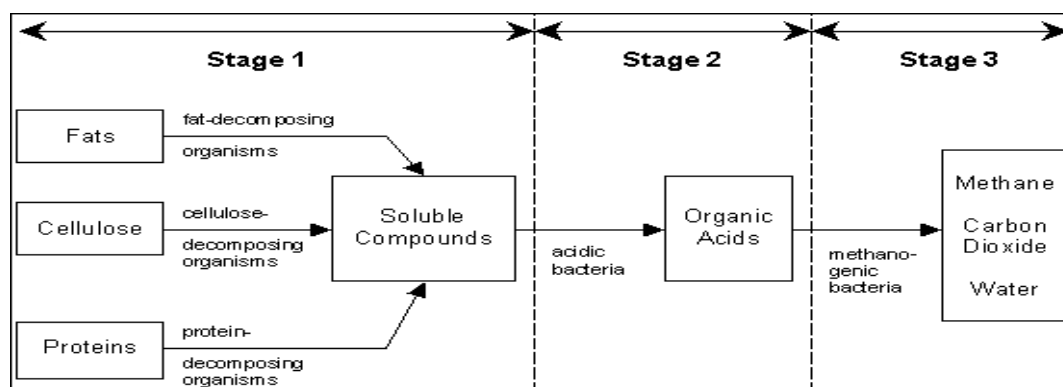


Figure 1 Anaerobic Digestion Process (Source: <http://energyfromwasteandwood.weebly.com/technologies.html>)

A variety of factors affect the rate of digestion and biogas production. The most important is temperature. Anaerobic bacteria communities can endure temperatures ranging from below freezing to above 135°F (57.2°C), but they thrive best at temperatures of about 98°F (36.7°C) (mesophilic) and 130°F (54.4°C) (thermophilic). To have an optimal digestion process, digesters must be kept at a consistent temperature, as rapid changes will interrupt bacterial activity. In most areas of the United States, digestion vessels require some level of insulation and/or heating. Some installations circulate the coolant from their biogas-powered engines in or around the digester to keep it warm, while others burn part of the biogas to heat the digester. In a properly designed system, heating generally results in an increase in biogas production during colder periods. Other factors, such as pH, water/

solids ratio, carbon/nitrogen ratio, mixing of the digesting material, the particle size of the material being digested, and hydraulic detention time also affect the rate and amount of biogas output. (USEPA, 2004).

2.4.2 Farm-Based Biogas Plants

A typical farm-based biogas plant is comprised of five parts: manure collection, anaerobic digester, effluent storage, gas handling, and gas use.

Manure Collection: Various types of manure management for dairy farms, swine farms, and poultry farms can be compatible with a biogas plant, though pretreatment or modifications are occasionally needed. Manure is usually stored as liquids, slurries, semi-solids, or solids. Different manure management operations lead to various manure solid content, which determines the choice of AD type (Figure 2). Liquid manure is suitable for the covered lagoon or fixed film digester. Slurry manure is best for the complete-mixed digester, and semi-solid manure works well for the plug-flow digester. Complete-mixed digesters have wider compatibility in terms of manure solid content. Manure with solid content of more than 13% is not recommended for biogas production. Pictures of flushing manure and scraping manure are shown in Figure 3.

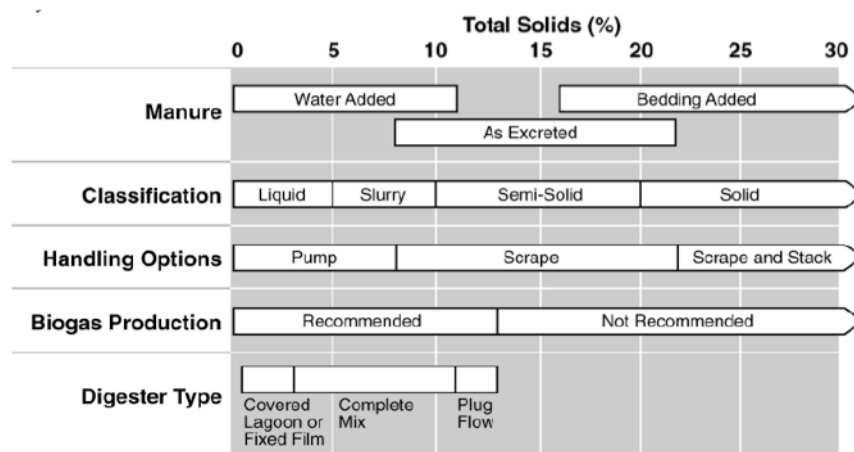


Figure 2 Appropriate Digester Type by Manure Characteristics and Management System (USEPA 2004)



Figure 3 Receiving Pit for Flush Dairy Dry Lot (left) and Chain Drag Scraper (right) (AgSTAR)

Anaerobic Digesters: The most common farm-based digester designs are covered lagoon, plug-flow, and complete-mix (Figure 4). Several other digester types have also been constructed in recent years, such as induced blanket reactors, fixed film, and batch digesters. A summary of the different design characteristics is exhibited in Table 1, and details of design features and operation conditions of different types of digesters are attached in Appendix E.

Table 1 Characteristics of Different Anaerobic Digester Designs (AgSTAR)

<i>Characteristic</i>	<i>Covered Lagoon</i>	<i>Complete Mix Digester</i>	<i>Plug Flow Digester</i>	<i>Fixed Film</i>
<i>Digestion Vessel</i>	Deep Lagoon	Round/ Square In/ Above-Ground Tank	Rectangular In-Ground Tank	Above Ground Tank
<i>Level of Technology</i>	Low	Medium	Low	Medium
<i>Supplemental Heat</i>	No	Yes	Yes	No
<i>Total Solids</i>	0.5- 3%	3- 10%	11- 13%	3%
<i>Solid Characteristics</i>	Fine	Coarse	Coarse	Very Fine
<i>HRT*(days)</i>	40-60	15+	15+	2-3
<i>Farm Type</i>	Dairy, Hog	Dairy, Hog	Dairy Only	Dairy Hog
<i>Optimum Location</i>	Temperate and Warm Climate	All Climates	All Climates	Temperate and Warm

*Hydraulic Retention Time (HRT) is the average number of days a volume of manure remain in the digester.



Figure 4 Digester Designs: Covered Lagoon (left), Plug-Flow (right), Complete-Mix (center) (AgSTAR)

Effluent Storage: The effluent of a digester is considered biologically stable because there are few biodegradable compounds remaining and no odor. The effluent's fertilizing value is enhanced over that of raw manure because nutrients in the manure are more readily available for plant uptake (Liebrand & Ling, 2009). Moreover, the pathogens and weed seeds in the raw manures are mostly removed. Waste storage facilities are required to store the treated effluent because the effluents cannot be applied in the field year round. The size of the storage facilities depends on the amount of effluent produced and the length of the non-growing season. The digested solids in the effluent are collected through solid-liquid separation. The solids are valuable for dairy cattle bedding, organic fertilizer, soil amendment, compost, and potting soil. Details of design features and operation conditions are enclosed in Appendix E.

Gas Handling: Every AD requires a gas handling system both to remove biogas produced from the digester and to transport it to the end-use, either for direct combustion or electricity generation. The gas handling system includes piping, a gas pump, a gas meter, a pressure regulator, and condensate drains. Sometimes, a gas scrubber is installed to avoid corrosion of the equipment.

Gas Use: Biogas can be utilized in nearly all of the same applications as natural gas. For some uses, however, biogas must be upgraded to achieve similar properties to natural gas. The three basic ways that biogas can be utilized are direct combustion for use on-site or connection to the natural gas grid, electricity generation for use on-site or connection to the electricity grid, and vehicle or stationary fuel. The direct combustion of biogas from small-scale biogas facilities for heat and steam use on the farm is the most common application. The heat obtained can be utilized to maintain the temperature of ADs (except for covered lagoons) in cold weather. Biogas produced can also be used for cooking, heating, and lighting on farms. Minimal treatment, such as desulfurization, is needed to prevent equipment corrosion.

Biogas can also be injected into the natural gas grid and distributed to households via the traditional grid. It is a more efficient way of using the energy than converting biogas into electricity and connecting to the electricity grid. Before connecting to the natural gas grid, biogas must be upgraded into pipeline quality gas by removing undesirable components and increasing the concentration of methane. This process is practiced in Sweden, Switzerland, Germany, and France (Persson & Jonsson, 2006), but not in the United States. National Grid and the New York City Department of Environmental Protection have been working together since 2010 to plan a pilot project in New York City that will inject landfill biogas into a distribution system (National Grid, 2010).

Similar to natural gas, biogas is also useful for generation of electric power or combined heat and power. A typical electricity generation system consists of an Internal Combustion (IC) engine or gas turbine, a generator, a control system, and an optional heat recovery system (USEPA, 2004). IC engines vary in capacity from a few kilowatts to several megawatts; their efficiency ranges from 18% to 25%. Gas turbine engines are most commonly available for facilities producing above 800 kW, but smaller size engines for farm-use have recently become available. The advantage of gas turbines is that recovery of low-pressure steam is possible for other applications. In addition, emissions of NO_x and the maintenance costs of gas turbines are very low. However, the conversion efficiency of gas turbines is not as good as that for internal combustion engines, and gas turbines tend

to cost more. There are two types of generators: the induction generator and synchronous generator. An induction generator operates parallel with the utility and cannot stand alone, while a synchronous generator can either function independently for on-farm use or be operated parallel with a utility. Most farm-scale systems employ induction generators because synchronous generators are more expensive. As about 75% of biogas energy is dissipated as heat in engines, it is common to install heat recovery systems to capture the waste heat. A properly-sized heat recovery system can improve energy efficiency by 40% to 50% (USEPA, 2004).

Looking to the future, fuel cells may become the predominant type of small-scale power plant (Persson & Jonsson, 2006). Fuel cells produce electricity through an electrochemical reaction, can be very efficient, and generate low emissions. Several business and municipal facilities already use fuel cells to make electricity and heat from biogas in the United States. A more advanced fuel cell is a tri-generation system developed by the University of California-Irvine. It is a high-temperature fuel cell that produces heat, electricity, and hydrogen at the same time (Brown, 2008).

Using biogas as a vehicle fuel is another emerging technology in countries like Sweden, Germany, Australia, Spain, India, China, and the United States (Persson & Jonsson, 2006). A 2007 report estimated that 12,000 vehicles are being fueled with upgraded biogas worldwide and predicted that 70,000 biogas-fueled vehicles would exist by 2010 (US Department of Energy, 2007). The application of biogas as a vehicle fuel is largely constrained by the availability of gas stations that offer a biogas alternative.

Chapter 3

Agricultural Biogas Abroad

3 Agricultural Biogas Abroad

3.1 Multilateral International Renewable Energy Regulations

In 1997, the Kyoto Protocol to the United Nations Framework Convention on Climate Change was adopted by 192 countries around the world (UNFCCC, 2009). The establishment of this treaty set up a binding target for all countries to reach in reducing their greenhouse gas (GHG) emissions. There are three main mechanisms under this protocol: the Clean Development Mechanism (CDM), Emission Trading Mechanism (the carbon market), and the Joint Implementation (JI) mechanism. Each helps countries meet their commitment in cutting GHG emissions in a cost effective way (UNFCCC, 2009). Biogas, a source of renewable energy that emits few GHGs (DENA, 2006), has been incorporated into many countries' national policies to meet the Kyoto Protocol targets.

3.2 Impact of Kyoto on Country-Specific Regulations

Based on the mechanisms provided by the Kyoto Protocol, countries have each set up different renewable energy targets and developed a wide variety of policies to promote different types of renewable energy technologies. Common approaches include subsidies, direct tax rebates and tax credits, and net metering laws. All of these measures help countries develop different renewable energy sources such as solar, wind, and biogas. Germany was the first country to introduce feed-in-tariff (FIT) laws to promote biogas. This measure was then widely implemented by other European Union (EU) nations. Beyond feed-in tariffs, many countries have developed Renewable Portfolio Standards (RPSs)¹ and their own, unique laws to support further development of the biogas industry. A brief explanation of some biogas-promoting measures adopted in countries where the biogas industry has developed further than in the U.S. – Germany, China, and Brazil, will provide a useful point of comparison for the in depth study of the U.S. biogas market.

¹ The details of net metering, a FIT, and an RPS will be explained in subsequent chapters. For the purpose of understanding the international framework, however, it is sufficient to say that these policies are included among the many policies implemented to encourage the development of agricultural AD.

3.3 Germany

Since the energy crisis in 1973, the German people have strongly advocated for the German government to invest in alternative energy research and development in order to avoid the negative impacts of a future energy crisis, to assure Germany's national energy security, and to help improve and conserve environmental conditions (GTZ, 2007). In addition to the favorable political climate, the German people were also inspired by the famous economist Ernst Friedrich Schumacher's idea that "Small is Beautiful." This emphasis on more small-scale technology propelled the development of agricultural biogas in southern Germany due to its nature as an innovative, affordable, and self-sustaining method of producing energy.

Germany's Success

- Substantial Public Support Stemming from 1970s Energy Crisis
- National Feed-In Tariff
- Nation-wide Support from Lenders Comfortable with the Technology

With such strong public and political awareness in favor of biogas technology in Germany, the national government passed the Renewable Energy Sources Act (EEG), Renewable Energies Heat Act (EEWärmeG), Gas Grid Access Ordinance (GasNZV), and Gas Grid Tariff Ordinance (GasNEV) to encourage the use of this

technology nationwide. The German government hoped biogas would help meet their high commitment to GHG emissions reduction, and boost domestic renewable energy production. In 2010, there were approximately 5,800 biogas plants in Germany producing a total capacity of 2,300 MW of electricity. In total, the current electricity generated from the biogas sector is about 15 billion kWh of electricity annually, and it equals 2.6% of German electricity consumption (4biomass, 2011).

The primary reason for the success of the biogas industry in Germany is the introduction of the FIT legislation for electricity from biogas plants. A FIT requires the utilities to buy the electricity produced by biogas generators, thus guaranteeing generators a source of revenue. The FIT has allowed many small companies and farm-based biogas plants to prosper in their early stages of operation. In 2000, Germany enacted the EEG to replace the early FIT. This new legislation ensures German sustainability in biogas development while meeting their high renewable energy target for 2020 – 20% of energy supplied should come from renewable energy sources. The EEG provides guaranteed payments to biogas plants for 20 years plus the start year, and cumulative bonuses for electricity produced from biogas. This Act also compelled power supply companies to connect with biogas plants to

secure the feed in from biogas production (Möller, 2009). In addition to EEG, Germany also promotes biogas development through EEWärmeG, which established that a minimum 30% of energy for heating come from the biogas sector.

With the strong support from government regulations and several market incentive plans, Germany has become the biggest producer of biogas in Europe by promoting farm-based and small-scale biogas plants in its market (DENA, 2010). It is also the leading producer of primary energy from biogas – 48.7% of the total in EU, and the leading biogas electricity producer – 41.7% of the EU total (The Houses of the Oireachtas, 2011). Moreover, Germany has set several long range targets for biogas production in national gas supply by 2030. In Germany's GasNZV, the target for biogas production is to reach 6% of total German natural gas consumption by 2020 – which equals 60 billion kWh, and to reach 10% of German natural gas consumption by 2030 – which equals 100 billion kWh (DENA 2010).

The German biogas industry is also successful because there are environmentally-oriented and conventional banks prepared to finance biogas projects. A number have dedicated experts and some provide readily accessible online forms – Umweltbank AG, DZ Bank, and DKB Deutsche KreditBank, which can facilitate the process of securing financing, and also serve as a signal to a farmer that the bank has experience and comfort to lend to biogas projects. An example of one of these forms translated into English is available in Appendix F. Germany, therefore, owes its successful biogas industry to the collaborative support received from the general public, the government, and lending institutions.

3.4 China

The development of China's biogas industry has taken a wholly different form from that of Germany. According to a 2006 report from the Development Research Center of State Council in China, the environmental pollution in rural areas have become the country's most critical problem (Su, 2006). Over 25 million tons of agricultural wastewater is dumped into regional water bodies annually, which has harmed its surrounding environment and

China's Success

- Environmental Necessity
- Strong Government Mandates Including FIT and Funding
- Thriving Agriculture Sector
- Abundance of Resources at Individual Household Scale

led to serious food and health security concerns for China's people. This critical situation compelled the Chinese Central Government in 2005 to incorporate agricultural biogas development into the "11th Five-Year National Development Plan." The government hoped that this would ameliorate the pollution in its vast rural areas, and facilitate the transition from a heavily coal-dependent economy into a cleaner renewable-fuel-based economy (UN ESCAP, 2007).

With full support from the Chinese Central Government, the agricultural biogas sector in China swiftly thrived in rural areas. Since 2006, many development funds have been created around the country to promote the growth of the biogas industry in support of the 11th Five-Year National Development Plan. The two major funds are the "Central Funds for Rural Environment Protection" and "Special Funds for Renewable Energy Development" (GIEC, 2006). As of 2009, these funds provided over 1.5 billion RMB and supported over 2000 rural villages in China to develop rural family biogas pool projects (each rural household with two pigs per capita per year) and rural environmental improvement projects (UN ESCAP, 2007; MEP, 2010).

This success was possible because of China's strong agricultural sector, which produces substantial biomass resources (Li, 2010). According to the China Biogas Society, there are nearly 700 million tons of agricultural wastes are generated annually, with an annual discharge volume of 7 billion tons of livestock and poultry manure. To harness this resource, the Chinese government began promoting underground, individual ADs in its rural areas in the 1970s (Henderson, 2007). Nowadays, biogas is commonly used in rural households for cooking and heating needs (Pan Zhu, 2006).

The first major legislation to promote biogas in China was The Central Document No. 1 from 2004-2009. This legislation has directed the speeding progress for rural household biogas and promoted the construction for medium and large-sized biogas plants at the national level (Li, 2010). In late 2009, the latest amended Renewable Energy Law (REL) further required feed-in prices and quotas for state grid companies to purchase electricity generated from renewable energy sources, including biogas (UN-Energy, 2007). This regulation also provides preference and incentive policies to subsidize numerous rural household projects and some medium and large-sized biogas projects (Li, 2010). In total, the Chinese National Treasury Bonds have been increasing its funding from 1 billion RMB – USD 146 million, in 2003 to 5 billion RMB – USD 731 million, in 2009 to support the national development of biogas projects (CRIEA, 2009).

With such strong support directly from the central government, the China Biogas Society estimated that the scope of biogas development in China would reach 40 million rural household biogas projects and 4,000 new large-sized biogas plants nation-wide, with an annual biogas production of 19 billion cubic meters in 2010. And by 2020, the number will increase to 80 million rural household biogas projects and 8,000 large-sized biogas plants nation-wide, reaching an annual biogas production of 44 billion cubic meters in total. Thus, unlike Germany, where the biogas development was driven largely by public support in response to an energy crisis, China's biogas development is driven by government mandates in response to an environmental crisis. China can also be distinguished from Germany because of the extent to which the biogas development is focused at the individual household level, in addition to the larger-sized plants.

3.5 Brazil

Brazil offers a third distinct example of how the development of agricultural biogas can become a successful industry. After the first petroleum crisis in the 1970s, the Brazilian government decided to reorient its national energy policy to alternative energy resources in order to diminish the negative effects associated with the importation of fossil fuels (Bastos, 2007). With the existence of a large scale domestic agricultural sector and substantial experience using ethanol and other forms of biomass to generate energy, Brazil has made tremendous progress in its agricultural energy industry. With such a successful background in agricultural energy generation, the development of agricultural biogas technology has also been strongly emphasized by government policy. This is because agricultural biogas is affordable, self-sustaining, and environmentally friendly. Developmental of this technology also benefits rural areas by providing another source of revenue, and helps increase Brazil's national alternative energy portfolio standards and meet its commitment to reduce GHG emissions under the Kyoto Protocol (DENA, 2010).

The animal husbandry industry, including swine and cattle, is an important cornerstone for Brazil's economy, which has supported Brazil's tremendous agribusiness for decades. In the 1970s and 1980s, there was a strong interest of biogas development in Brazil

Brazil's Success

- Kyoto Protocol Clean Development Mechanism
- Thriving Agribusiness Industry Developing Many Agricultural Energy Sources
- Government Response to 1970s Energy Crisis and Environmental Issues of Developing Countries

because of the abundance of agricultural resources, but development was unsuccessful due to the unsatisfactory market scope and lack of knowledge about the technology (DENA, 2010). Brazil was not able to capitalize on the energy potential of the agribusiness sector until the Kyoto Protocol was enacted with the CDM. As one of the major still-developing countries that ratified Kyoto Protocol, Brazil has fully utilized the CDM established under the treaty in order to promote an agricultural biogas industry in its rural areas (UN ESCAP, 2007). The CDM allows developed countries to meet part of their GHG emission reduction commitment by investing in GHG emission reduction projects in developing countries (UNFCCC, 2009).

Through this mechanism, Brazil has been cooperating with many developed countries such as Denmark and Germany in developing AD projects (Embrapa, 2006). These biogas projects have not only brought positive environmental and economic effects to the husbandry industry in the rural areas of south and southeast Brazil, but they also benefit the developed countries by generating additional carbon credits for those countries. Due to the CDM, the development of anaerobic lagoons began to expand rapidly in the south, southeast and mid-west regions of Brazil (IAEA; Emprapa, 2006). In 2009, there were 157 registered CDM projects in Brazil, and biogas has the highest share of those projects with 40 (DENA, 2006). In Minas Gerais state, the second most populous and second wealthiest state in Brazil, there are 300 biogas digesters currently employed, and their capacity can reach 60,000 to 70,000 kWh (Embrapa, 2006). Based on a report from the German Energy Agency (DENA), it estimates that the total potential of the biogas industry for Brazil can reach over 111.3 million cubic meters of biogas or 76.8 million cubic meters of bio-methane per year (DENA, 2006). It is also believed that with the continued expansion of CDM projects, the biogas projects will prevail in more regions of Brazil and bring more income to the farmers. These projects will also assist Brazil in meeting its own RPS and meet their GHG emission reduction target.

Brazil, therefore, developed a thriving agricultural biogas industry for reasons wholly-different from both Germany and China. Brazil was able to capitalize on the opportunities created by the Kyoto Protocol, and make it's already thriving agribusiness industry an even greater source of income. Additionally, biogas made sense in Brazil because the nation was already investing in agricultural energy generation in the form of ethanol and other biomass fuels. Like Germany, Brazil's renewable energy development has been a direct response to the energy crisis of the 1970s. Brazil's biogas development is also similar to that in China because it has also been pursued because of the environmental benefits so important to a developing country.

Chapter 4

National Landscape of Agricultural Biogas

4 National Landscape of Agricultural Biogas

This chapter gives an overview of the current U.S. agricultural biogas market and obligations. The information was gathered through research and interviews with farmers and nonfarmer key stakeholders (Appendix G).

4.1 The Market

According to AgSTAR¹, the U.S. Environmental Protection Agency's (EPA's) voluntary outreach and educational program for the development of farm-based ADs, there are 160 operational ADs in the U.S., with 80% installed on dairy farms and 15% on swine farms (Table 2). The total generating capacity of the existing ADs is 57.1MW. The national distribution of existing ADs is displayed in Figure 5. Most of the digesters are concentrated in California, Missouri, New York, Pennsylvania, Vermont, and Wisconsin. The existing operational ADs generate about 374,000 MWh of energy and have decreased methane emissions by about 50,000 metric tons annually – equivalent to 1 million metric tons of CO₂.

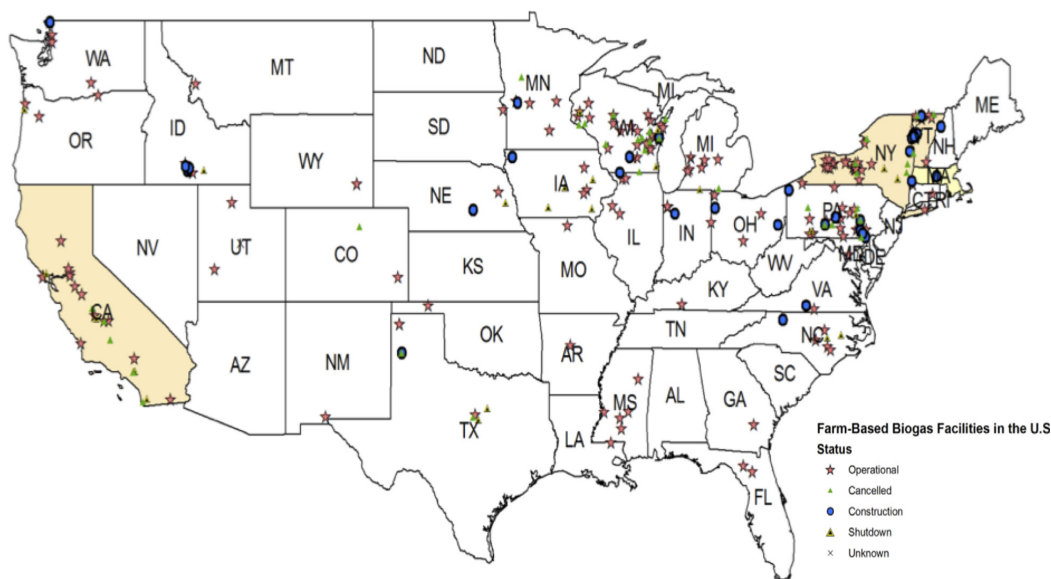


Figure 5 Distribution of Farm-Based AD Facilities in the United States (Rose Yuan Wang, 2011)

1 AgSTAR encourages the capture and use of methane from animal manure for many reasons, including odor control, biogas production, environmental resource protection, and alternative energy generation.

Table 2 Operational Anaerobic Digesters in the United States (AgSTAR, 2010)

<i>Animal Sector</i>	<i>Number of Operation AD</i>	<i>Generating Capacity (MW)</i>
<i>Swine</i>	24	2.9
<i>Dairy</i>	129	50.3
<i>Beef</i>	2	2.6
<i>Poultry</i>	5	1.3
<i>Total</i>	160	57.1

Even with this development, the number of operational biogas farms in the U.S. is dwarfed by the number of potential candidate farms. AgSTAR has identified over 8,000 candidate farms for AD, of which nearly 6,000 would be swine farms (Table 3). Candidate farms were screened according to the size of the farm and the compatibility of the farm's existing manure management system with ADs. Candidate farms include:

1. Dairy farms with more than 500 cows and with anaerobic lagoons or liquid slurry manure management systems;
2. Swine farms with more than 2,000 animals and with anaerobic lagoons or liquid slurry manure management systems; or
3. Swine farms with more than 5,000 animals and with deep pit manure management systems.

Table 3 Candidate Farms for Biogas Production in the United States (AgSTAR, 2010)

<i>Animal Sector</i>	<i>Candidate Farms</i>	<i>Energy Generation Capacity (MW)</i>	<i>Energy Generation (MWh/yr)</i>	<i>Methane Emission Reductions (Thousand Tons)</i>
<i>Swine</i>	5,596	804	6,431,527	905
<i>Dairy</i>	2,645	863	6,802,914	908
<i>Total</i>	8,241	1,667	13,144,441	1,813

The distribution of candidate farms is shown in Figure 6. Iowa is the leading state in terms of swine candidate farms, followed by North Carolina. California has the most dairy

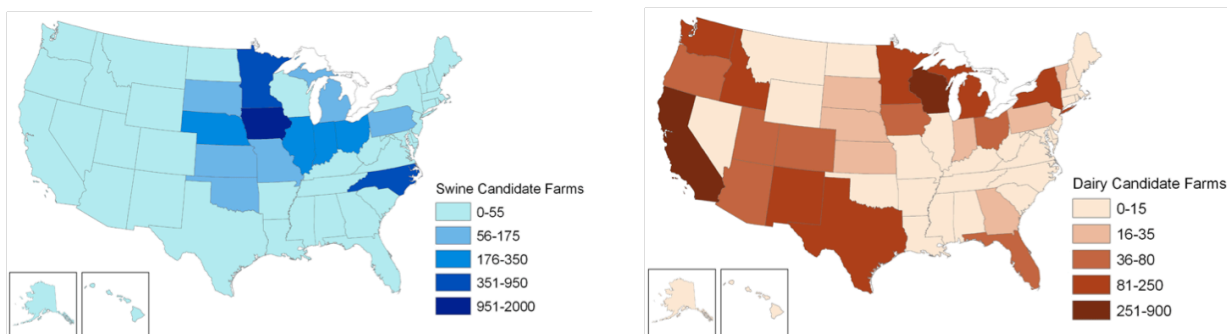


Figure 6 Candidate Swine and Dairy Farms in the United States

candidate farms, followed by Wisconsin.²

According to AgSTAR, “[b]iogas recovery systems at these facilities have the potential to collectively generate more than 13 million megawatt-hours (MWh) per year and displace about 1,670 megawatts (MW) of fossil fuel-fired generation.” Further, more than 34 million metric tons of carbon dioxide would be eliminated from the U.S. pollutant portfolio every year.

There is also potential for agricultural AD development that is not included in the AgSTAR database. First, farms that are not individually large enough to support AD can work cooperatively with neighboring farms to develop and operate an AD facility. A collection of farms in Massachusetts are currently trying to develop an AD facility using the cooperative model, and will be discussed further in Chapter 9. Additionally, though not included in the candidate farms count above, poultry operations represent additional, smaller-scale AD opportunities.

4.1.1 AgSTAR Overview

Municipal treatment plants have collected biogas from anaerobic sludge digestion since the early 1900s (Wright, 2004). The market for biogas accelerated in the 1970s due to the oil embargo of 1973 and subsequent energy crisis. According to Wright, at least 71 ADs were installed on farms as a direct result, though many were abandoned once fossil

² Though Wisconsin has the second highest number of candidate dairy farms, Idaho is the state with the second highest potential for energy production from agricultural AD because the farms in Idaho are generally larger than in Wisconsin, and Idaho’s waste management practices are better suited to energy production (AgSTAR, 2010).

fuel energy prices dropped. Only 25 of these remained operational by 1995. AgSTAR was established within EPA in 1994 in collaboration with the U.S. Department of Agriculture (USDA) and the U.S. Department of Energy (DOE). Both AgSTAR and USDA contribute technical tools, such as industry lists, screening forms, and instructional manuals; research, including feasibility studies like the California Biomethane Study (Krich et al., 2005); outreach and marketing; policy and standards development; and financial support including guidance in estimating capital costs. AgSTAR's funding is not direct, but rather supportive.

USDA's financial support funnels primarily through its Rural Development and Natural Resources Conservation Service. USDA has several programs that offer grants and financial incentives to farms considering investing in digester facilities (Chapter 5). AgSTAR also joined the Methane to Markets Partnership, a nonbinding international mechanism promoting cooperative efforts to reduce methane emissions.

In May 2010, EPA and USDA announced an expansion of their AgSTAR relationship. The new interagency agreement dedicated \$3.9 million to support farms in overcoming the barriers to establishing and maintaining operational on-farm biogas facilities. As the press release describes, "The collaboration will expand technical assistance efforts, improve technical standards and guidance for the construction and evaluation of biogas recovery systems, and expand outreach to livestock producers and assist them with pre-feasibility studies" (EPA, 2010).

4.1.2 Dairy Industry Overview

In the United States, over 80% of on-farm AD projects have been on dairy farms. Although the capacity exists for swine, poultry, and beef farms, the technology of the containment and manure management system on dairy farms are best suited to biogas production. Furthermore, the political and state-policy support for biogas production mainly exists in dairy-producing states. Because of the concentration of biogas facilities on dairy farms, and the significant potential for growth of dairy power production, the information in this report focuses largely on the dairy industry.

The economic feasibility of biogas projects is closely tied to the health of the farm sector in which it will be built. The economic context helps explain the past building trends as well as the potential for growth in the near future. According to USDA's Economic Research Service, the average herd size has grown from 19 cows in 1970, to 120 cows

in 2006 (USDA, 2007). Figure 7 shows this increasing concentration of dairy operations. Because biogas production requires a certain scale of dairy operation, the increased concentration can facilitate biogas production, while the AD process can help offset some of the negative aspects of concentrated farming by reducing odor and bacteria.

Another significant element of agricultural economics that affects the feasibility of biogas production is the economic health of the farm, which is largely dependent on the price farmers receive for their product. Many farms experienced financial difficulty after the sharp decrease in milk prices due to the recession - from \$18.45 per hundredweight (cwt) in 2008 to \$12.94 per cwt in 2009.³ During the low period, a number of farms were unstable financially, which limited ability to take on risk, debt, and expensive capital-intensive projects like developing an AD facility, and applications for AD projects declined. Interestingly, a farms' sensitivity to milk price fluctuation can also be somewhat relieved by producing biogas. Once a farm is able to receive revenue from biogas production, its diversified revenue stream will leave it less vulnerable to milk price fluctuations.

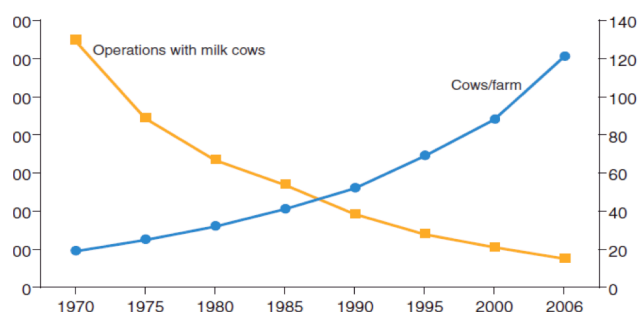


Figure 7 Change in Dairy Farms and Cows Per Farm

4.1.3 Market Barriers

Economic Feasibility: Throughout the peer-reviewed literature; agency, industry, and non-profit organization websites; and state and local casebooks, the greatest barrier to implementing AD technology on farms is the cost. The following chapters will discuss financing options and obstacles in more detail; however, it is first helpful to understand the challenges to funding and financing that currently deter candidate farms from implementing AD facilities.⁴

³ Fortunately, Milk prices are projected to rise steadily but slowly through 2020, with a 2020 projection of \$18.70 per cwt. USDA Agricultural Projections for 2011-2020. <http://www.ers.usda.gov/Publications/OCE111/OCE111e.pdf>

⁴ In this report, the term funding refers to the actual money received, and the term financing refers to the mechanisms by which that money is received.

Although the cost of farm-based ADs varies with the capacity and facility type, there are certain types of costs associated with all projects that amount to a significant financial, time, and resource investment. According to Hahn et al. (2010), investments and costs for typical agricultural biogas plants can be grouped into the following categories:

- Planning: feasibility and engineering studies, permits, consulting services;
- Equipment: digester and related equipment, buildings, storage facilities, grid interconnection infrastructure;
- Feedstock: purchase and transport of off-farm substrates for co-digestion;
- Operation and maintenance: spare parts, personnel; and
- Financing: interest, fees.

AgSTAR conducted a cost analysis in 2010 for 40 ADs which found that the upfront capital costs of developing an AD facility decreases as the size of the farm increases, regardless of the technology employed (Figure 8). There is debate about which digesters are the most cost effective per head of cattle, but for even the smallest farms, the upfront capital cost for a digester system of at least \$700,000 is undeniably significant (Lazarus, 2008). In any case, both USDA and AgSTAR data support the claim that capital costs create a substantial development barrier.

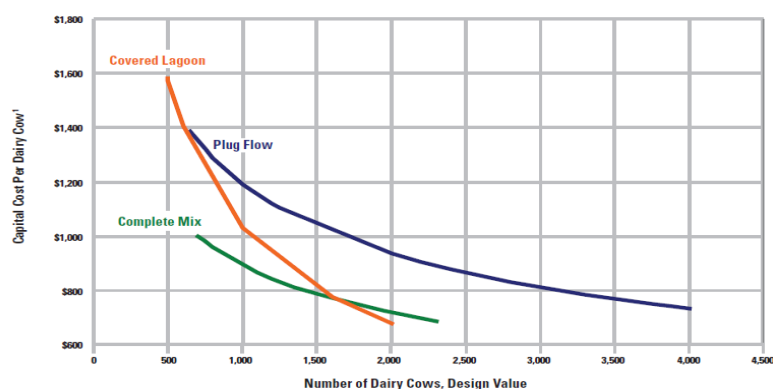


Figure 8 Capital Cost per Dairy Cow by Digester Design (AgSTAR, 2010)

The ancillary equipment costs can also be extensive. The average cost of a post-digestion solids separation system is approximately 6.4% of the total system cost, the hydrogen sulfide treatment about 3.1% of the total, and utility charges about 5.3% of the total. Additionally, the electricity generator cost is about 40% of the total system cost, and the flare cost, when the biogas is flared for

odor control, is about 3.3% of the cost that a generator would entail. Once the system is functioning, the annual operation and maintenance costs of ADs are estimated at 3% of the total (Beddoes, Bracmort, Burn, & Lazarus, 2007).

On-Farm Management: Among the digesters that do enter the market successfully, failure can later result due to lackluster profits as well as discontinued or weak management of the biogas system (Wright, 2004).

The economic feasibility of a biogas project depends on the ability of potential revenue sources to cover or exceed capital and operational requirements, and hopefully generate a profit. The potential revenue sources include: use/sale of electricity and heat, renewable energy credits, use/sale of byproducts such as bedding and fertilizer, and selling carbon credits.

4.2 Funding and Finance

The costs of developing any renewable energy generating facility, including an AD facility, are burdensome. Assembling enough funds to cover the initial start-up costs of an AD facility is the greatest challenge that a developer faces when trying to enter the market. Usually, a project will aggregate funds from public funding programs, private debt financing, and equity or working capital from the farm itself. This section will provide an overview of each of these components, as well as the supporting policy structures that facilitate the development of biogas projects on candidate farms.

4.2.1 Private Financing

While some public funding is available, usually over half of the funding for a biogas project must come from the farm (farmer equity) and loans from commercial lenders. This private financing can and has taken on a number of different forms worldwide, with traditional financing and project financing being the most common.

In traditional financing, the bank grants a loan to the farm, which then uses the loan to help fund the project. In the traditional model, the liability of the farm depends on the assets of the biogas plant and the farm itself, meaning that the farm's assets are collateral so secure the loan. In many cases, this loan is combined with funding from other sources such as public grant programs. The traditional model is the typical financing tool for single farmers and is the most common model in the U.S.

For project financing, the biogas project itself is regarded as a legal entity, so project funds are granted to the project itself, rather than the farm. The project finance model is difficult to get for small projects, and is typically used when multiple shareholders (i.e., a number of farms) are involved. The farmers may form a cooperative in which each farm receives a share of the revenue proportional to the amount of substrate (waste) that farm supplies for digestion. In most project finance cases, lenders provide project debt for up to 80% of the facility's installed cost and accept a debt repayment schedule over 7 to 15 years (AgSTAR, 1997).

Other, less-common financing tools also exist. Investment funds combine funds from several small investors for one biogas project, and cost and benefits are shared between the investors. Lease financing, another tool, encompasses a range of strategies in which a farm leases all or part of a project's assets from the asset owner. Though these are the conventional financial tools used for biogas facilities, there is also opportunity for creative collaborations and partnerships between the public sector, private sector, and utilities. One example is the community digester for the Dane County Cow Power Project in Wisconsin, which is a partnership between a biogas energy developer, three dairy farms, and Dane County. (Dane County, 2009).

Among the financing methods described above, each produces a different weighted cost of capital, which depends on the share of project funds financed with debt and equity, and on the cost of that debt or equity (i.e., interest rate on debt, rate of return on equity). The lowest financing costs over time are associated with cost-sharing by public agencies coupled with debt financing, debt financing alone, lease financing, and project financing becoming increasingly more expensive. Due to the high capital costs, equity capital of 20% to 30% of the total capital cost is usually required for any financing, with the debt-to-equity ratio often related to project risk (Hahn, 2010). This equity commitment demonstrates the financial stake that the farmer has in the project. Two key measures lenders use to evaluate the financial strength of a project are the annual debt coverage ratio, which is the ratio of operating income to debt service requirements, and the rate of return on equity (ROR). While a break-even project is satisfactory to the owner, lenders prefer an ROR of 12% to 18% (AgSTAR, 1997).

For all financing tools, there are certain common factors that affect lenders' likelihood to provide financial support. In deciding whether or not to lend money, lenders examine the expected financial performance of a project and other underlying factors of project success. These factors include a farm with a capable manager in a good financial state, a well-

researched venture, mitigated construction risks, a proven technology at a feasible scale, a signed interconnection agreement with a utility, equity commitment, proper permits, and local support. If a farm has good credit, adequate assets, and the ability to repay borrowed money, lenders will generally approve the loan (AgSTAR, 1997; Harris, 2008).

Historically, because of their small size, agricultural biogas projects have experienced difficulty securing debt financing from traditional commercial lenders, because small projects are perceived as risky. Though some lenders may be comfortable with the technology, the projects are still relatively small. Thus, farms must often secure debt financing with banks that specialize in working with the agricultural community, where a lending relationship has already been established. Another opportunity is to seek funding through energy investment funds that finance smaller projects. In countries such as Germany, where the biogas industry has matured, environmentally-oriented and conventional banks are comfortable financing biogas projects. In the U.S., the financial sector has not yet developed the same tools and expertise, but could learn from their counterparts abroad.

4.2.2 Public Funding

Biogas projects are only economically feasible when funded through a combination of both public and private sources. As discussed above, the ability to secure private financing strongly depends on availability of supporting policies and programs, which assure lenders that the project will benefit from the government support system during the operational phase. Because government funding plays such a large role in both providing funds to development projects, government financing often drives the development of renewable energy projects. Thus, it is imperative that developers are aware of the full breadth of funding options available to them. The key policies that provide necessary structural assurance for renewable energy development are described below. This is an overview of renewable energy incentives, and is not specific to agricultural AD. Furthermore, some of these measures may not apply to AD in certain states. The public funding available specifically for agricultural AD at the federal level, and in our four case study states will be discussed in detail in the following chapters.

Grants: According to the Database of State Incentives for Renewable Energy (DSIRE), 21 states currently possess grant programs for renewable energy, though 4 of these states—Washington, Idaho, Montana, and Vermont—only have programs that are administered by local governments, utilities, or private sources.

Tax Credits: Similarly, 23 states and the District of Columbia provide tax credits for renewable energy, with 20 states including both personal and corporate credits.

Net Metering: More than 80% of U.S. states have adopted net metering programs in which a facility is able to run a retail utility meter backwards when its renewable energy generator returns excess power to the grid. When running the meter backwards, farmers are credited at a rate that equals approximately 4 times the rate they would have received if the electricity was sold to the utility (Ferrey, Laurent, & Ferrey, 2010). States define the renewable energy sources eligible for net metering as broadly as “Renewables and Cogeneration,” to more specific labels, including Vermont’s explicit reference to AD. The renewable production capacity ranges from less than 10 kW to no size limit at all. Some states allow for open-ended carry-over between months, while others limit this to within a calendar year.

Feed-In Tariffs (FITs): Though much more common in Europe, FITs are slowly infiltrating the U.S., and are viewed as a more reliable alternative to net metering programs, especially for small electricity generators. FITs determine and guarantee that generators are able to connect to the electricity grid and receive a long-term contract for the sale of their electricity (Ferry, 2009). Vermont was the first state to implement a FIT program in the U.S. successfully (Chapter 6), though California followed soon after with a similarly comprehensive program for small producers with a particular aim to encourage livestock biogas (CPUC, 2008). Hawaii, Oregon, Washington, and Gainesville, Florida have also instituted FITs for certain renewable energy resources, but do not include biogas. Several other states have introduced legislation for varying levels of FIT programs. Additionally, there have been unsuccessful federal attempts to enact a national FIT, modeled after Germany’s system.

Property Tax Exemptions: Thirty-four states plus Puerto Rico offer property tax exemptions either through state, local, or a combination of programs. Regardless of authorizing entity, most property tax exemptions exclude the increased land value resulting from the renewable energy system improvements, from the taxable value of the land.

System Benefits Charge (SBC): An SBC is a surcharge tax on utilities used for collecting funds from consumers. The SBC’s proceeds are then employed to support various renewable energy activities. Between 1998 and 2012, approximately \$3.5 billion will be collected for energy trust funds in 14 states with existing renewable SBCs. More than half of the amount collected will be in California alone (Ferrey, Laurent, & Ferrey, 2010).

Public Benefits Fund:

Eighteen states plus the District of Columbia support energy efficiency and renewable energy projects through the collection of funds via a minimal consumer charge on electricity bills or utility contributions. Twelve of these states—California, Connecticut, Illinois, Massachusetts, Minnesota, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Wisconsin—have founded the Clean Energy States Alliance, which coordinates the funds collected for renewable energy (Pew Center on Global Climate Change, 2011). According to the DSIRE,⁵ public benefits funds currently range from \$800,000 offered in Pennsylvania for 2010 to \$363.7 million in California for 2010. Many states have plans that extend to 2017, while a few expire in 2011. The Oregon Energy Trust is not scheduled to expire until 2025.

Development Process

1. Technology Research
2. Vendor Selection
3. Discussions with Utility and Project Attribute Purchaser
4. Grant Acquisition, Financing
5. Utility System Impact Study, Interconnection Design
6. Permitting
7. System Design and Engineering
8. Competitive Bid Process for Subcontractor Selection
9. Equipment Procurement
10. Facility Construction
11. Digester Loading, Heating, Mixing
12. Utility Interconnection, Commissioning

(Source: Raker, 2011)

Though the development of an AD facility is not a linear process, especially receiving funding and obtaining necessary permits, there are certain steps that almost all facilities need to take (see Development Process box).

⁵ Established in 1995, the Database of State Incentives for Renewables & Efficiency is an ongoing project of the North Carolina Solar Center and the Interstate Renewable Energy Council. The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy funds the DSIRE, primarily through the Office of Planning, Budget and Analysis. The site is administered by the National Renewable Energy Laboratory, which is operated for DOE by the Alliance for Sustainable Energy, LLC.

4.3 Government Regulations

Agricultural facilities are subject to numerous government regulations. The primary laws that impact the development of an AD facility are the federal Clean Water Act of 1972 (CWA) and Clean Air Act of 1970 (CAA), state environmental, agricultural, and public utility regulations, and local building and zoning requirements. This list is not exhaustive, but rather gives a general overview of the obligations farms planning to install an AD must meet. It is strongly suggested that the owner or operator of a farm seeking to install an AD contact their state environmental and agricultural agencies, as well as their municipal planning board, to determine what steps need to be taken prior to constructing an AD facility.

4.3.1 Permitting

The owner of a farm seeking to install an AD must obtain a discharge permit, preconstruction permit, and a permit to use and sell the solid output of its AD. These requirements are pursuant to the CWA, CAA, and agricultural regulations.

Required Approvals for Construction and Operation

- Permit to emit air pollutants
- Permit to discharge liquid effluent
- Permit to use and sell solid effluent
- Permit to build in accordance with Building Code
- Permit to store gas

The CWA was established with the main policy goal of eliminating pollutant discharges into the nation's waterways. It sets forth a means of achieving this goal by requiring facilities to obtain permits for the discharge of polluted water into surface water, and regional controls for

sources of groundwater pollution. The CWA regulates discharges from concentrated animal feeding operations (CAFOs) through the National Pollutant Discharge Elimination System (NPDES) Program. All farms designated as small, medium, or large CAFOs must obtain a NPDES permit prior to any discharge to surface waters.⁶

⁶ Generally, a dairy or swine farm should qualify as a medium CAFO for the use of an AD facility to be economically feasible.

The CWA's state delegation provision allows any state, once approved, to administer its own NPDES Program. Thus, most discharge permits are granted by state environmental agencies. An authorized state permit program can adopt requirements equal to, or more stringent and broader than the federal NPDES Program. However, relevant requirements under the CWA must be implemented through the state permit programs and any permits issued by a NPDES approved state remain federally enforceable.

The modern CAA was established to protect and enhance the quality of the nation's air resources, and to encourage and assist the development of regional air pollution prevention control programs. The CAA and EPA set standards for national air quality and the CAA requires that each state develop a state implementation plan (SIP) to implement these standards in their region. States have discretion as to the means of achieving the federal standards but each SIP must be approved by EPA. All regulations adopted under the SIPs are published in the Code of Federal Regulations (CFR) and thus are federally enforceable.

The CAA requires each SIP to designate and set emission standards for the different air quality control regions (AQCRs) within its borders. The owner or operator of a farm seeking to install an AD facility must obtain a preconstruction permit from the air pollution control agency that regulates the AQCR in which the farm is located. If an AD facility plans to emit greater than 25,000 tons of CO₂ a year it is required to report its aggregate annual emissions of CO₂, CH₄, and N₂O under EPA's GHG Reporting Rule.

State agricultural regulations require farms seeking to construct an AD facility to obtain licensed permission to use the AD's solid output as bedding or to sell such output as bedding or fertilizer.

4.3.2 Utility Regulations

In addition to the permitting requirements, a farm may be subject to further regulation if the developer wants to sell the electricity. In this case, the facility is subject to public utility regulation so that the farm can interconnect to the electricity grid (Ferry, 2009). The overarching statute governing the transmission and sale of electricity by the federal government is the Federal Power Act of 1935 (FPA). This statute made it clear that the

federal government has jurisdiction over the wholesale⁷ sale and transmission of electricity in interstate commerce, or the retail transmission of electricity in interstate commerce. To understand the nature of utility regulation, though, it is first necessary to explain the electricity grid.

The grid is roughly composed of 4,800 power generation resources, cables that connect the resources with consumers, and hardware that workers manage to integrate in an energized instantaneous network. Because one element of the grid cannot function without the other, the grid is subject to substantial regulation to ensure that it functions smoothly. With technological improvements, the grid is also constantly changing; state and federal regulators have been trying to restructure the industry in a way that replaces old, dirty electricity with cheaper, cleaner, renewable electricity (Ferry, 2009). One such change that must occur to integrate renewable electricity into the grid is that transmission infrastructure must be constructed from the generation facility to the load center, where it can be sold to end-users.

Though it is the Federal Power Act (FPA) that gives the federal government authority to regulate the wholesale sale and the transmission of electricity in interstate commerce, it was the Public Utility Regulatory Policies Act of 1978 (PURPA) that opened the door for federal regulation of independent generators like agricultural ADs. PURPA was “designed to combat the nationwide energy crisis,” (Ferrey, Laurent, & Ferrey, 2010), and requires that utilities connect to qualifying facilities (QFs) and purchase that facility’s electricity at the utility’s avoided cost (Fisher, 2009). These relationships are managed through a variety of contract options, most notably formal interconnection agreements and power purchase agreements. When the Energy Policy Act (EPA) of 1992 was passed, the definition of “qualifying facilities” was broadened to include nearly all generation facilities. Thus, utilities are required to provide access to their transmission lines for all generating facilities that wanted to sell their electricity. Government bodies have since struggled with managing and standardizing interconnection procedures among transmission providers.

The Federal Energy Regulatory Commission (FERC) is the body that regulates the transmission and sale of electricity at a national level, and largely focuses on setting

7 There is a distinction between the wholesale sale of electricity, and the retail sale of electricity. Wholesale sale occurs when the electricity is sold to a buyer who intends to turn around and sell the electricity again, such as to a public utility. Retail sale occurs when the electricity is sold to a final end user, such as from a utility to a residential home.

fair rates. (Tomain, 2009). FERC is empowered to regulate the rates for the wholesale sale, and any transmission of electricity in interstate commerce. The FPA creates a bright line between state and federal jurisdiction, with the federal government clearly presiding over the wholesale sale of electricity. Because most generators sell electricity directly to a utility for resale, generators are typically regulated by FERC if the sale of electricity implicates interstate commerce. Though most AD facilities do not sell electricity in interstate commerce currently, the federal structure is useful to understand because many state systems are modeled after it.

FERC sets rates and implements regulations through independent system operators (ISOs) and regional transmission organizations (RTOs). An ISO coordinates, controls, and monitors the operation of the electrical power system, usually within a single state, or a small collection of states. An RTO generally performs the same function as an ISO, but over a larger region. At the state level, state public utility commissions (PUCs) set rates. Thus, much like the interconnection grid itself, interconnection regulations are comprised of regulations established by a network of regulators with varying, yet overlapping, jurisdictions that any connecting generator must learn to navigate.

State policies vary greatly regarding interconnection options with utilities, retail electricity rates,

and distributed power pricing (Lazarus, 2008). Utilities do not view relationships with smaller electricity generators enthusiastically since their operations are more efficient and profits more readily realized with utility-sized generators (Wright, 2004). Requirements

To begin the contract process, digester developers may need the following information:

1. Avoided cost rate schedules
2. Contract Options - for renewable energy projects
 - A. Buy-sell agreement
 - B. Surplus sale agreement
 - C. No sale parallel agreement
 - D. Net sale agreement, if available
 - E. Any other currently available agreements
3. Interconnection requirements
4. Any charges, riders, rate schedules that may be applied to the project (e.g., standby charges)

(Source: AgSTAR Handbook, 2006)

for insurance and safeguards that the utility requires if the generator fails or is turned off further complicate that relationship. The AgSTAR Handbook explains that contractual agreements between farms with digesters and utilities typically fall into three categories of buy all-sell all, surplus sale, and net metering (Roos, Martin, Jr., and Moser, 2006). The Handbook outlines the information that a digester developer should have to initiate the utility contracting process.

4.3.3 Local Regulations

The local process for approving the construction of an AD facility generally does not differ from the process of any other type of new construction, except for zoning. All new construction and modifications are subject to the state and municipal building codes which cover, among other things, materials, electrical, plumbing, and dimensions. Also, because the operation of an AD requires gas storage, a license from the state or local fire department may be required.

The difference when it comes to zoning for an AD facility depends on what a state or municipality determines the AD actually is for the purposes of agriculture. Agricultural areas are zoned as such and prohibit the use of such areas for any other type of use. A facility that simply operates an AD as a manure management system for its own farm waste would most likely still be considered an agricultural use. If an AD facility accepts waste transfers from other facilities, however, it may be considered a waste treatment facility, which is no longer an agricultural use. This would require a variance from the zoning board. The need for a zoning variance can severely delay, or even block the installation of an AD. Thus, farms that propose to accept waste transfers for AD should determine how the facility is likely to be classified under the relevant zoning ordinances and by the zoning board.

4.4 Renewable Energy Schemes

4.4.1 Renewable Portfolio Standard (RPS)

As of January 2011, 29 states plus the District of Columbia and Puerto Rico had an RPS, all of which included biogas within one or more of the program's tiers, typically

as “landfill gas” or within “biomass.”⁸ Seven more had voluntary standards. Some biogas inclusions contain restrictions regarding the use of the energy produced on site, the location of the biogas generation in state, capacity of the digester, or crediting stipulations according to the date of the facility’s certification. Twenty-three of the 31 states have penalties for non-compliance, and approximately 2% to 40% of electricity is required to come from renewable sources across the RPS programs.

4.4.2 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a market-based regional regulatory program that aims to reduce GHG emissions. It is based on CO₂ auctions, tracking, and offsets. The states participating in RGGI include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, with each state operating a CO₂ Budget Trading Program. Each state’s CO₂ Budget Trading Program limits emissions of CO₂ from electric power plants, issues CO₂ allowances, and establishes participation in regional CO₂ allowance auctions. RGGI is applicable to facilities implementing ADs for the production of biogas through its offsets program. CO₂ offsets are project-based GHG emissions reductions. RGGI participating states currently allow regulated power plants to use a carefully chosen group of qualifying offsets to meet up to 3.3% of their compliance obligations. Offsets may be purchased from any project within the participating states.

A Model Rule guides Vermont, New York, and Massachusetts RGGI regulations, and all 3 states have comparable offset regulations. All three states award CO₂ offset allowances to project sponsors of CO₂ emissions offset projects or CO₂ emissions credit retirements, such as ADs, that have reduced or avoided atmospheric loading of CO₂ or CO₂ equivalent. Subject to the relevant compliance deduction limitations, CO₂ offset allowances may be used by any CO₂ budget source for compliance purposes. All three agencies’ regulations specify that offset projects are eligible for avoided methane emissions from agricultural manure management operations (See 310 CMR 7.70(10)(e); 6 NY ADC 242-10 et seq.; VT ADC 16-3-101:22-1001 et seq.).

8 Quantitative RPS data in Excel format spreadsheet sourced from <http://www.dsireusa.org/rpsdata/index.cfm>

4.4.3 California Bioenergy Action Plan

The 2006 Executive Order S-06-06, amended in 2011, committed California to a target of generating 20% of the State's renewable energy from biopower (biomass to electricity) by 2010, and maintaining this ratio through 2020. Executive Order S-06-06 also committed the State to a target of producing 20% of its biofuel use (biomass-based transportation fuels) within the State by 2010, 40% by 2020, and 75% by 2050. The California Air Resources Board (CARB) is responsible for coordinated oversight of efforts made by state agencies to promote the use of biomass resources. The Bioenergy Action Plan will help the State achieve its RPS goal to require retail sellers of electricity to increase the amount of renewable energy they procure each year by at least 1% until 20% of their retail sales are served with renewable energy by the end of 2013. CARB and the regional agencies are working to implement standards that would facilitate the increased contribution of biopower to the RPS goal.

4.4.4 Renewable Energy Credits (RECs)

A REC is a commodity that represents an element of electricity that is produced from a renewable source. Markets have been created around RECs, resulting in their trade (Miller, 2008). An important consideration that most states with RPS mandates must take into account is whether RECs can be used by a utility to satisfy its mandate. One objection to state and proposed federal mandates to this policy is that they do not possess the natural resources readily available to them to generate power from renewable sources (ibid).

4.4.5 Carbon Credits and Offsets

A carbon credit is a tradable permit representing the right to emit one ton of the six primary categories of GHGs. Carbon offsets are a means for the government and private companies to earn carbon credits. A carbon offset is a one ton reduction in the emission of GHGs. The installation of an AD reduces the amount of GHGs that would have been released by a farm not using the pollution control technology. Thus with those reductions, farms operating ADs may enter the market to sell their offsets. A farm seeking to sell offsets obtained by the operation of an AD must register with an offset program such as RGGI. The owner or operator of the farm should register once the AD commences operation. The offset programs verify the offsets from a facility and provide rules for monitoring the generation and trading of such offsets.

Chapter 5

Federal Regulatory Scheme

5 Federal Regulatory Scheme

5.1 Environmental Regulations

The provisions discussed in this chapter are the federal requirements that are applicable to farms seeking to construct an AD facility. Generally, the permitting process has not been a significant barrier to the construction and operation of ADs. Farms seeking to install an AD must coordinate with federal and/or state environmental agencies.

5.1.1 The Clean Water Act

The CWA requires a NPDES permit for any AD facility that would result in the discharge of polluted wastewater into the nation's waterways. The NPDES Program is specific to point source¹ discharges and leaves the regulation of groundwater pollution sources, or nonpoint sources, to the states. NPDES permits establish limitations on the amount of pollutants that may be discharged, record keeping and reporting requirements, and describes the facility's nutrient management plan (NMP).²

Any farm seeking to construct an AD facility that would require a NPDES permit must first obtain a certification from the state in which the facility proposes to discharge. The state must certify that the discharge will comply with the applicable provisions of the CWA (33 USC § 1341). Once certified, permit applicants must submit NPDES Form 1 and Form 2B to the permitting authority at least 180 days before the date on which the discharge is to commence (Appendix H). A CAFO's³ NPDES permit application requires information about, among other things, the activities conducted by the applicant which

1 Point sources are fixed facilities from which wastewater flows directly into surface waters. Nonpoint sources do not have a single point of origin or do not introduced into a receiving surface water body.

2 Nutrient Management Plans contain the Best Management Practices (BMP) necessary for a facility to meet the requirements of its discharge permit. A NMP ensures, among other things, adequate storage of waste and land application protocols, and identifies records to be maintained.

3 Animal Feeding Operations (AFOs) are designated as CAFOs if they are determined to be a significant contributor of pollutants to U.S. waters. They are primarily categorized as Large CAFOs, which confine at least 700 dairy cows or 10,000 swine less than 55lbs, Medium CAFOs, which confine at least 200 dairy cows or 3,000 swine less than 55lbs, and Small CAFOs, which don't meet the conditions of Medium CAFOs but are significant contributors of pollutants to the U.S. waters. These categories are not exhaustive, but provide a guide to entities likely to be regulated. Once an AFO qualifies as a CAFO for one type of animal, it must obtain a NPDES permit for all facility activities that result in the discharge of pollutants.

require it to obtain an NPDES permit, a listing of all permits or construction approvals received or applied for, the type of containment and storage and total capacity for manure, litter, and process wastewater storage, and estimated amounts of manure, litter, and process wastewater generated per year. Prior to applying for a permit it is strongly recommended that an applicant contact the regulating agency.

If a farm's installation of an AD would only result in groundwater discharges, it must comply with its state's groundwater discharge requirements. Generally, state environmental agencies require permits and/or reporting for pollutant discharges to groundwater.

5.1.2 The Clean Air Act

The CAA requires that EPA establish National Ambient Air Quality Standards (NAAQS) for pollutants deemed harmful to both public health and the environment. EPA designates each AQCR as either (1) a nonattainment area, which does not meet or that contributes to the air quality in a nearby area that does not meet the NAAQS for the pollutant, (2) an attainment area, which is any area that meets the NAAQS for the pollutant, or (3) an unclassifiable area, due to limited information. The state air pollution control agencies set emissions standards pursuant to these designations. Permit requirements vary depending on the air quality classification of the area where the facility is located and whether the facility is a major or minor source of pollutants.⁴

Any AD facility that would be a new source of criteria air pollutant emissions must obtain a preconstruction permit.⁵ Preconstruction permits are granted by state air pollution control agencies, which are generally divided into AQCRs designated by the SIP. Each SIP adopts the requirements for new sources of air pollution that are established by the air pollution control agencies for their specific AQCR. The state air pollution agencies set limitations on the amount of pollutants an AD facility may emit through its operation and

4 In a nonattainment area, a major source is any stationary pollutant source with potential to emit more than 100 tons per year is considered a major stationary source. In attainment areas the cutoff level may be either 100 or 250 tons, depending upon the source.

5 An AFO can emit ammonia (NH₃), nitrous oxide (N₂O), hydrogen sulfide (H₂S), carbon dioxide (CO₂), methane (CH₄), total reduced sulfur (TRS) compounds, volatile organic compounds (VOC), hazardous air pollutants (HAP), and particulate matter (including PM 10 and PM 2.5) – all of which are criteria pollutants. ADs work to reduce emissions of methane, VOC, hydrogen sulfide, and ammonia.

the land application⁶ of the AD's output (effluent). The emission limitations are technology based and differ depending on whether the farm is in an attainment or nonattainment area. A farm seeking to construct an AD facility in an attainment area must comply with the best available control technology (BACT) standard, while an AD facility in a nonattainment area must comply with the lowest achievable emission rate (LAER) standard.⁷ The construction of an AD on a farm must comply with the emissions requirements established by the state in which it is located.

Following construction, the air pollution control agencies set record keeping and reporting requirements for the operation of AD facilities. The reporting requirements are implemented through either operating permits granted by the state air pollution control agency or simple registration procedures with the state air pollution control agency.

5.2 Utility Regulations

The first step a generator must take to connect to the grid is to submit an application to the relevant ISO or RTO. Once the generator submits this application, the generator is placed in the interconnection queue on a first come, first serve basis. In most regions, the interconnection queue is severely backlogged, with hundreds of projects awaiting grid connection. California has estimated a 57,000 MW backlog.⁸ (Fisher, 130-31). Thus, often one facility can be in the interconnection queue for years before the project is even reviewed. In order to be efficient, then, a prospective project must file its application with the ISO or RTO well before the facility is ready to begin construction.

In addition to the length of time spent in the interconnection queue before receiving a contract to connect to the grid, the cost of the technological improvements necessary to

6 Discharge of wastewater onto the ground for treatment or reuse.

7 A facility's emissions must be equal to or lower than what they would be if the facility employed the applicable BACT or LEAR.

8 These numbers are deceptively dire. Many of the projects in the interconnection queue never materialize into actual projects, or even go through the interconnection study phase. Because the queue is so long, potential projects file their application very early in the projects development, and so many of these projects fail for reasons that have nothing to do with the challenges of connecting to the grid, and therefore are removed from the queue.

connect to the grid is also a substantial hurdle for project developers. Often, especially with agricultural AD, the facilities are built far from existing transmission lines, and physical connections need to be constructed over long distances. One facility in Vermont spent \$300,000 building a 3-mile transmission line to connect with the grid. Furthermore, it is also often necessary to make physical improvements to existing structures so they can accommodate the increased flow of electricity through the cables. Both of these processes are costly, and the brunt of the cost is borne by the generator. FERC has established a bifurcated approach to allocating the costs of interconnection. “Interconnection facilities,” or extending the grid to new generators, are charged to the generator. The generator must also bear the up-front costs of “network upgrades,” but is eligible to be reimbursed by the utility through credits against transmission charges. In sum, connecting to the grid is an extremely lengthy and costly process for generators. (Fisher, 123-24).

5.2.1 Small Generator Standard Process

The application to be submitted to the ISO or RTO is determined by the size of the proposed facility. In 2005, FERC issued Order No. 2006, which governs the interconnection process for small generator facilities. Any generator that expects to produce less than 20 MW of electricity is considered a small generator. Because most agricultural AD facilities produce far less than 20 MW of electricity, they are governed by the order if they are subject to FERC regulations. This is called the Small Generator Interconnection Process (SGIP) and the Small Generator Interconnection Agreement (SGIA).⁹ A valid application request must be submitted with a \$10,000 deposit that is applied towards future studies, and a demonstration of site control. At this point, the generator is placed in the interconnection queue. Review begins with a scoping meeting between the generator and the transmission provider to determine the breadth and schedule of necessary studies. Then, the transmission provider begins an in depth study of the proposed interconnection including: (1) a feasibility study, (2) a system impact study, and (3) a facilities study. The purpose of these studies is to determine the safety and reliability of the proposed interconnection. These studies determine changes that must be made to the proposed plans, other studies that need to be conducted, and a detailed cost and completion timeline for all necessary improvements. The generator is responsible for all costs associated with these studies, and must post a deposit at the beginning of each study.

9 There are also standard processes for Large Generators of more than 20 megawatts, and inverter-based generators of 10 kilowatts or less. However, most agricultural AD facilities will not fall within these categories.

After these studies are completed, the generator and the transmission provider negotiate any additional transaction-specific provisions of the agreement, and the interconnection agreement is filed and executed. Only at this point may construction of the interconnection facilities begin. (Fisher, 128-29). Generators are afforded flexibility to accommodate the need to submit the application during the beginning stages of development. The generator can withdraw the application any time, with no penalties except losing its place in the queue and paying all costs already incurred. Also, generators may suspend the construction and installation of interconnection facilities for up to 3 years after the SGIA has been signed, subject to certain limited costs. Finally, the generator can modify its request at any time; however there are strict limits placed on changing the proposed electric output of the facility (Fisher, 2009).

5.2.2 Fast Track Process

FERC Order No. 2006 also includes provisions for two expedited processes. The first is a “Fast Track Process” application for small generators that expect to produce no more than 2 MW of electricity. The largest agricultural AD facilities only generate about 700 kW of electricity, so they all could at least apply for the streamlined process if they are regulated by FERC. This process can be much faster and less expensive than the standard SGIP process, in that it has a standard processing fee so it does not require deposits. In place of the scoping meeting and three studies, technical screens are used to quickly identify safety and reliability issues. If the facility passes the screens, the transmission provider offers the generator an SGIA. If the facility does not pass the screens, the transmission provider can still find that safety and reliability will not be affected by the facility and offer an SGIA. Or, if the transmission provider determines that the project might adversely affect the safety and reliability of the grid, the transmission provider must offer to conduct a supplemental review of the project, and identify upgrades necessary for the interconnection. This supplemental review is still at the expense of the generator. Once the generator agrees to pay for all recommended upgrades, the transmission provider can offer an SGIA. If, after the supplemental review, the transmission provider is still unconvinced of the safety and reliability of the project, the interconnection request must be evaluated using the standard SGIP.

It is within this federal scheme that all regional ISOs and RTOs must determine which generators do and do not connect to the grid. ISOs and RTOs are, however, given significant discretion to modify the framework to their particular region, subject to FERC approval. Additionally, FERC is currently reevaluating these processes to address issues of

interconnection queue backlog. The Midwest ISO recently received FERC approval for a process to address many timing and cost issues inherent in the process, and it is expected that this process will be adopted by other ISOs.

5.3 Federal Government Funding Sources

In addition to the financial incentives available to agricultural AD facilities from the state in which the farm is located, the federal government offers several financing incentives that are available through an application process to farmers in any state. Below is a discussion of the most commonly used federal financial incentives for agricultural AD development, as well as the programs with the greatest potential. For a full list and explanation of the federal funding resources available, see Appendix I.

5.3.1 Grants

The primary method by which the federal government currently funds agricultural AD development is by distributing money to these facilities through a number of grant programs.

Rural Energy for America Program (REAP) Grant: Renewable energy facilities can apply to the USDA Rural Development department for a grant of up to 25% of the proposed project's cost. These grants are specifically for agricultural producers and small businesses, and can be used for the purchase and installation of renewable energy facilities. The maximum dollar amounts vary, depending on the purposes, but cannot exceed \$500,000 for renewable energy facilities; and receiving one of these grants is very competitive. USDA now also offers REAP Feasibility Grants, which are intended to fund agricultural producers and rural small businesses to conduct studies and determine cost-effective opportunities for new renewable energy measures. These grants can be up to 25% of the cost of the study, or \$50,000, whichever is less. If this grant is applied for in conjunction with the REAP guarantee loan program, then the application is given priority.

Environmental Quality Incentives Program (EQIP): EQIP offers financial and technical help to eligible livestock producers for the installation and implementation of structural or management practices to improve the environmental quality on agricultural lands. Eligible facilities apply to the state in which they are located in order to receive the

funds, and the states have discretion over how the funds are allocated; with some restrictions from the federal government. EQIP offers contracts ranging from 1 to 10 years to help share the costs of certain conservation practices through incentive payments and cost-share grants. EQIP may cost share up to 75% of the cost of these conservation practices, with certain limited facilities being eligible for up to 90% cost sharing. An AD facility may not exceed, through the aggregate of grants and cost sharing, more than \$450,000 for all contracts entered during the term of the 2008 program.

U.S. Department of Treasury Renewable Energy Grants (Cash Grants): Any facility that is eligible to take the Investment Tax Credit (ITC) (see below) can, instead, elect to receive a one-time cash grant in the amount of the ITC—this includes those facilities eligible to take the ITC in lieu of the Production Tax Credit (PTC). The grant can only be taken for facilities that begin construction before December 31, 2011, and are operational by January 1, 2014. This program has already been extended once beyond its 2010 sunset, but it is unclear whether these extensions will continue. The government issues a check in the amount of 30% of eligible investment costs within 60 days of the grant application date or the facility becoming operational, whichever is later. So, the Cash Grant functions as cash in hand, as opposed to a reduction in taxes in the future.

5.3.2 Loans

The federal government's programs for lending money to developers of agricultural AD facilities involve the government acting as both a lender and as a guarantor of the loans. Thus, some programs involve the facility borrowing money directly from the government, whereas others involve a private lending institution as a third party.

Rural Energy for America Program (REAP) Guarantee Loan Program: This loan guarantee encourages the commercial financing of renewable energy facilities for, among others, livestock producers and rural small businesses, including agricultural AD. USDA's Rural Development department guarantees up to \$25 million in loans or 75% of the proposed project's cost, whichever is lower. This works in conjunction with the REAP Grant Program, and together the two may not exceed 75% of the project cost.

5.3.3 Tax Credits

The largest federal incentive available for renewable energy development is promulgated by the Internal Revenue Service through tax credits. A tax credit is a dollar for dollar reduction in the amount of taxes paid in a given year. Often, tax credits are allocated to investors—people or entities who provide funding for a facility but have no role in the operations of the facility—to reduce their tax liability. Acquiring tax credits is often the primary incentive for investors to invest in these projects, and therefore the availability of tax credits is an important factor in a developer’s plans to build a renewable energy facility. Despite this, interviews indicated that most AD facilities have not taken advantage of these valuable tax credits, and do not work with investors. They are worth discussing in detail, however, because of the potential benefits for agricultural AD development.

Federal Renewable Electricity Production Tax Credit (26 USC § 45):

Traditionally, the only tax credit available to agricultural AD facilities was the PTC, which remains the cornerstone of federal policies supporting renewable energy. The PTC was originally enacted as part of the EPAct of 1992 and has been periodically extended, with each extension lasting only for a limited period. The value of this credit is based on amount of energy produced, and requires that energy must be sold to an unrelated party. The credit is available for electricity generated from “qualified energy resources” and sold by the taxpayer to a third party during the taxable year. One qualified energy resource is open-loop biomass, which the Internal Revenue Code defines to include any agricultural livestock manure and litter, including wood shavings, straw, rice hulls, and other bedding material for the disposition of manure. Additionally, a qualified facility is one that was originally placed in service between October 22, 2004 and December 31, 2013, and has a nameplate capacity of not less than 150 kW.

The amount of the credit available per kWh changes from year to year, but is currently 1.1 cents per kWh. The credit can usually be claimed every year for the 10 year period beginning on the date in which the facility was placed in service.¹⁰ The uncertainty of whether or not the PTC will continue to be extended, however, is one of the primary drawbacks of this tax credit. Because the development process of a facility can take years, there is often hesitation on the part of investors who fear that the PTC will no longer be

¹⁰ It is reduced for projects that receive other federal tax credits, grants, tax-exempt financing, and subsidized energy. The amount of the credit claimed also reduces the extent to which the owners of the facility can claim depreciation reductions.

available by the time the facility is placed in operation. Another drawback is that the PTC is tied to the amount of energy produced, and not the cost of the facility, so if an expensive facility is not as efficient as anticipated, the PTC will not offset as much of the development costs as necessary. Moreover, the PTC is not available for many agricultural AD facilities because it requires that the electricity produced be sold to an unrelated third party, and often agricultural AD facilities produce electricity for their own use only.

Business Energy Investment Tax Credit (26 USC § 48): Beginning in 2009 with the American Recovery and Reinvestment Act, the ITC was extended to include open-loop biomass projects that would have qualified for the PTC. Qualifying facilities now have the option of opting out of the PTC, and electing to take a one-time corporate tax credit in the amount of 30% of the eligible cost of the facility.¹¹ This typically includes costs that are integral to the generating facility, excepting ancillary costs like transmission lines and site improvements (IRS Notice 2009-52). The deduction, however, is tied entirely to costs of the facility, not to electricity produced, and there is no requirement that the electricity be sold. Thus, this credit is available for many agricultural AD facilities that could not claim the PTC due to these restrictions.

The entire 30% credit can be taken in the first year that the facility is placed in operation, but it vests only 20% a year over a period of 5 years. This means that the owner who claims the tax credit—usually an investor—must maintain his ownership interest in the facility for at least 5 years, or that owner will have to pay a portion of the tax credit claimed back to the government. After 5 years, the entire credit will have vested, and the owner who claimed the credit can sell his interest in the facility without having to repay any of the credit. Currently, this credit is available for facilities placed in service by December 31, 2013, and it is unclear whether the expanded ITC credit will be extended beyond this date.

¹¹ Like the PTC, the ITC has implications for the amount of depreciation that can be claimed by the owners of the facility.

Chapter 6

Agricultural Biogas in Vermont

6 Agricultural Biogas in Vermont

6.1 Introduction

Vermont stands out as the major success story in the U.S. agricultural biogas industry. According to AgSTAR, there are currently 11 operational digesters and 6 under construction in Vermont, giving it the highest ratio of digesters to candidate farms of any state in the nation. A table of these farms and projects is available in Appendix C. The agricultural biogas landscape in Vermont is very homogeneous, and the business model for biogas project development has been relatively constant across most of Vermont's farms. All but one dairy use the same technology from GHD Inc., a company that provides assistance throughout the development process. Additionally, all farms benefitted from the expertise and support services of the Central Vermont Public Services (CVPS) utility and its consultant. As the industry grew, these consultants learned a lot about finance and permitting programs in Vermont and were able to transfer knowledge between farms. This chapter provides an overview of the successful agricultural biogas industry in Vermont, with particular emphasis on the permitting process and project funding and financing practices.

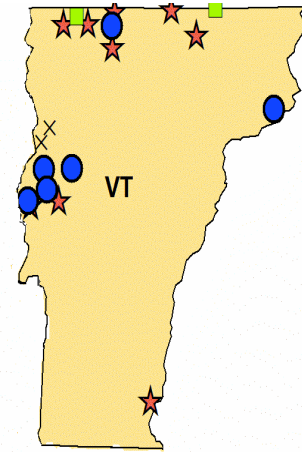


Figure 9 Anaerobic Digester Projects in Vermont

6.1.1 Biogas Industry in Practice

The growth of the biogas industry in Vermont is primarily a result of CVPS's Cow Power Program, which was developed in 2003 following a state directive for utilities to examine new ways of developing renewable energy resources. This program provides grant funding towards installing ADs, helps farms complete the permitting process and secure grant funding, and connects the farm to the grid as a power supplier. A funding opportunity for this program was created through negotiations that took place when CVPS sold its share in a nuclear energy facility. A portion of the proceeds of the sale were applied to renewable energy programs that benefit ratepayers.

Because Vermont is a small state with a limited number of large dairies, CVPS knows the farmers in Vermont who are interested, or who can create a viable project. CVPS primarily works with these farmers, but will also help other farms complete a feasibility analysis to understand the potential costs and revenues of an AD project if asked to do so.

Based on interviews with farmers and stakeholders, the primary motivations for taking on AD projects are the opportunity to diversify and increase their revenue stream, realize cost savings from the bedding produced as a byproduct of the AD process, and to reduce odor. Finally, because the biogas industry is more mature in Vermont, the necessary infrastructure and support services are already in place to aid future projects.

6.2 Regulatory Framework

For farmers to build a project in Vermont, they must obtain a number of permits. Support for navigating this process is available to farms through CVPS Cow Power, and may be available from the technology vendor as well.

6.2.1 Water Permits

Background: The Vermont permit program is operated by the Department of Environmental Conservation's (VT DEC) Wastewater Management Division pursuant to VT ADC 2-3-402 et seq. However, the State prohibits point source discharges from animal feeding operations. Vermont regulates nonpoint source AFOs separately from the NPDES program, regardless of CAFO status. The Division of Agricultural Resource Management and Environmental Stewardship's Agricultural Water Quality Section (ARMES) regulates the waste operations of these facilities.

Compliance: A farm seeking to construct an AD must first determine whether it is a small, medium, or large CAFO. All medium and small CAFOs, or Medium Feeding Operations (MFOs), must apply for a General Permit, which prohibits the discharge of wastewater from a farm's production area to waters of the state, and requires manure and other wastes to be land applied according to a NMP. MFOs must submit a Notice of Intent to Comply with the conditions of the General Permit (Appendix J). If ARMES proposes to issue a General Permit to an MFO, it must first publish a draft permit for public comment for at least 30 days. After the public comment period, the agency will issue the General Permit to the facility. The General Permit remains in effect for five years.¹ Large Feeding

¹ If the ARMES determines that the facility is not in compliance with the General Permit or that its NMP may result in unpermitted discharge to surface water, the agency may require the owner of the facility to obtain an individual permit.

Operations (LFOs) must obtain individual permits. LFOs must have a NMP developed or approved by a certified nutrient management planner, in order to receive a certification from the State. The NMPs must indicate, among other requirements, all land receiving application of manure or any other source of nutrients, that it meets the standards of Vermont Accepted Agricultural Practices (AAPs), a list of any methods of managing waste including AD, and plans for record keeping. The process of developing an approvable NMP is one of the main points of difficulty in obtaining a discharge permit. Once a NMP is approved and state certification is granted, the facility may apply for an individual permit through the VT DEC.

A farm that is required to obtain an individual permit must submit an application to ARMES including, among other requirements, a description of the proposed AD, the NMP and state certification, and a description of the AD facility. A completed application is reviewed by ARMES in consultation with VT DEC. Once the initial review and approval is complete, an ARMES Advisory Group will review the application, the facility owner must initiate newspaper notice, and ARMES will hold a public informational meeting for LFO applications. The Advisory Group review is a formal 45 business day application review period. If a permit determination is not made within 45 days, the permit may be awarded to the facility by default. If a farm does not have significant complications with its application, this process should take approximately six months.

6.2.2 Air Permits

Background: Under Vermont's Air Pollution Control Regulation, Subchapter V5-501 et seq., Vermont has two AQCRs: the Champlain Valley Interstate AQCR and the Vermont Intrastate AQCR. The state requires a permit for new construction, installation, or modification of air pollution sources by VT DEC.

Compliance: The owner or operator of a facility seeking to install an AD must provide notice to VT DEC and submit paperwork to prove that the construction or modification of the facility would comply with the Vermont SIP. If VT DEC decides that the proposed new or modified source is a major emitting source, or if the permitting of such source would cause the AQCR to violate its ambient air quality standards, the source will be subject to the most stringent emissions rate (MSER). Such facilities must submit an air quality impact evaluation with their permit application. The process for obtaining a construction permit should take approximately three months, though a significant threat to the state's compliance with ambient air quality standards could extend the process. The

fees for obtaining a construction permit should cost approximately \$8,000 to \$12,500, depending on whether the AD is a major or minor facility (Appendix K). Once an AD is constructed, the facility is required to register the source annually with the DEC if it emits at least 5 tons of any pollutant per year. To register, the facility must provide the Air Pollution Control Officer with necessary source emissions data and a registration fee.

6.2.3 Public Utility Connection

Generators not under the jurisdiction of FERC must comply with interconnection regulations promulgated by the Vermont Department of Public Service.² DPS has adopted different standards for net-metered systems that are 150 kW or less, net-metered systems of more than 150 kW, and systems that are not net-metered. Since June 2010, any system that is 150 kW or less can follow the standards for net metered systems of that size. For systems larger than 150 kW, but not subject to ISO regulation, they must submit an application very similar to that under FERC. This application also has a Fast Track option.

6.3 Project Funding and Finance

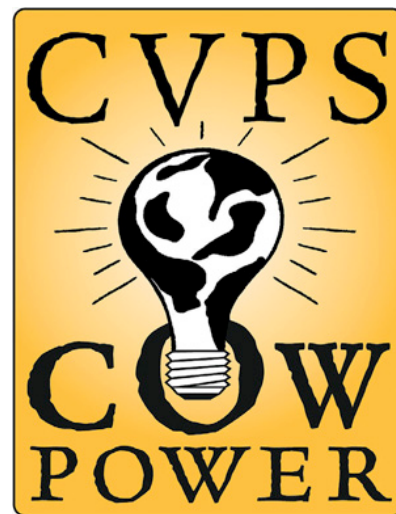
6.3.1 In Practice

While bedding production and odor control are two primary reasons for farmer interest in AD, these two elements alone do not provide enough of a financial incentive for farmers to take on a project. Additionally, the price of milk does not typically give farmers enough extra funding to invest in innovative projects outside the dairy production process. Vermont has found a way to identify and attribute value to AD projects and their benefits through a number of incentive programs. The two primary policies that have driven the success of AD in Vermont are the CVPS Cow Power Program and the FIT provided through the Standard Offer Program.

² A generator may not be under the jurisdiction of FERC if the electricity is sold directly to end-users (in retail), or the generator is a part of a distributed generation (DG) system. These systems are generally somewhat isolated from the normal grid in what is called a “microgrid.” The electricity from these facilities is gathered at one nearby load center, where it is then connected to the usual “macrogrid.” Because these generators do not connect to the macrogrid themselves, they are regulated by the state instead of the FERC - even though the electricity is sold at wholesale—because they do not participate in interstate commerce.

CVPS Cow Power has driven production through creating community support for AD and providing the technical assistance described above. Most importantly, it has developed a way to monetize the community support for the dairy industry and renewable energy through a \$0.04/kWh production incentive, which pays the farmer a premium over the price for energy.³ The second key policy that drives the market is the Standard Offer Program passed by the legislature in 2009, which requires utilities to purchase the electricity generated from eligible sources under long-term contracts. These incentives generate the future revenue guarantee that makes biogas production economically feasible. There is also significant support for programs providing upfront funding for capital and planning costs.

In Vermont, the cost to build systems has ranged from approximately \$1,200 to \$1,600 per cow (Cow Power, 2010). Engine operation and maintenance costs have been higher than anticipated, likely due to high concentrations of hydrogen sulfide and the prohibitive cost of gas scrubbing equipment, approximately \$0.030/kWh to \$0.04kWh (Cow Power, 2010). Revenue from these projects can be generated from the programs discussed above, and additional cost savings are generated from the digested solids recovered for animal bedding, which for a 1,000 cow farm in Vermont can save a farm up to \$100,000/year; and from offset water heating costs, approximately \$40,000. Given the potential revenue and savings, the payback period for a development in Vermont is about 7 years. The electricity generators run at about 70% capacity factor. So for the 1,000-cow dairy producing 200 kW, about 1,200,000 kWh of electricity are produced per year. In Vermont, the value is about \$0.115/kwh, or \$138,000 of annual revenue. This is combined with saving about 10,000 gallons of fuel oil, or about \$40,000 in water heating costs, and offsetting about \$100,000 in sawdust purchases normally used for bedding (Cow Power, 2010).



CVPS Cow Power Logo (Source: CVPS)

As discussed in Chapter 4, farmers have to aggregate funding from a number of public funding programs, provide equity, and secure private financing for a project to be economically feasible. In Vermont, grant funding has covered approximately 40% to 50% of most projects, and the breakdown of funding by source is comparable across a number

3 The \$0.04/kWh premium is paid into the CVPS Renewable Development Fund (RDF) if there is more demand than supply and when RECs are not available on the market.

of the farms. The typical project breakdown is provided below:

- ◆ USDA Rural Energy for America Grants (\$300,000 – \$350,000 up to 25% of project)
- ◆ Vermont Clean Energy Development Fund (\$250,000)
- ◆ CVPS Renewable Development Fund (\$150,000)
- ◆ Vermont Agency of Agriculture (\$75,000)

In Vermont, the private lender for most projects has been Yankee Farm Credit, a bank with whom a number of farms already have a relationship. Farmers may take out all their loans from one lender, or can split the loans between establishments (one farm interviewed reported half of the loans from Yankee Farm Credit and the other half from the Vermont Economic Development Authority).

6.3.2 Financing Sources

Below is detailed information about Vermont's primary government funding sources. This list is not exhaustive, and additional funding sources are described in Appendix I.

Grants

Clean Energy Development Fund (CEDF): Pre-Project Financial Assistance Grants of up to \$100,000 are available to assist with costs incurred prior to operation. The facility must be completed within one year of the award, and these grants also require that a 20% or 50% cash match be provided, depending on the award's size. Large-Scale System Grants are awarded for facilities expected to produce more than fifteen kW of power, with all electric generation projects connecting directly to the grid. The maximum grant award in this category is \$250,000, and requires a 50% cash match of which no more than 25% can be from in-kind resources. Projects must be completed within two years of the award.

Central Vermont Public Service Corporation (CVPS) Biomass Grants: CVPS, Vermont's largest electric utility, receives credits from several nuclear energy insurance companies pursuant to a sales contract. A large portion of the credit amount received is used directly to fund grants and other incentives to encourage the development of AD facilities that use agricultural products. In addition to providing a project coordinator to help sites

develop an AD facility, the grants support project development, project operations, and interconnection to the grid. The amount and types of awards are made on a case-by-case basis.

Vermont Agency of Agriculture, Food, and Markets (VAAFM): The VAAFM offers funding for improvements and innovation in manure management systems. The agency is particularly concerned with nutrient management, manure handling, and supports manure management projects that have a renewable energy component to them. For details on these grants you must contact the agency.

Production Incentives

The Vermont Standard Offer Program: The Vermont Energy Act of 2009 expanded the SPEED Program to effectively establish the first statewide FIT program in the U.S. The technologies included in the program are Landfill Methane, Farm Methane (agricultural biogas), Wind, Solar Photovoltaic, Hydropower, and Biomass (Appendix L). No project can exceed 2.2 MW, and no one technology can comprise more than 25% of the total capacity cap of 50 MW. These projects must apply for and be granted a “Certificate of

IN DEPTH: VERMONT’S FIT AND AGRICULTURAL BIOGAS PROJECTS

Twenty-seven farm-methane projects, of 78 total projects, were originally accepted for processing, 4 of which have since withdrawn. The 23 remaining applicants ranged in project capacity from 40 kW to 1,173 kW, with an average of 327 kW per project. As of September 23, 2010, 9 total projects were listed in the queue for consideration, but had not yet been processed, one of which was a farm methane developer with a stated capacity of 225 kW. As of December 2010, 12 total standard offer projects were up and running, 9 of which are farm methane producers. Examples of producers include Berkshire Cow Power, Gervais Family Farm, Chaput Family Farms, and Green Mountain Dairy Farm. For the month of December, these sites produced a range of electricity from 44,745 kWh to 193,787 kWh. The rate for farm methane resources was originally set at an interim price of \$0.16/kWh. As of January 15, 2010, the standard offer rate for farm methane was listed as \$0.1359/kWh for year 1, increasing to \$0.1503/MWh for year 20, accounting for inflation. Of the AD projects currently underway, 7 are paid \$0.1359/kWh, while 2 receive \$0.1600/kWh, presumably due to the date on which they signed the standard offer contract.

Public Good,” with projects of 150kW or less conforming to the standards for a “Certificate of Public Good for Net Metered Systems.”

All Vermont retail electricity providers are required to purchase the electricity generated by eligible renewable energy facilities through long-term, typically 20-year, contracts with fixed standard rates. The intention is to encourage renewable energy investment and development by guaranteeing a reasonable return on the investment. Labeled a Standard Offer Contract mechanism, the FIT program in Vermont offers a fixed rate for electricity that is required to be less than the anticipated market price. FITs may only provide for rates equal to the rate fixed by the PSB, unless the contract was formed prior to the Vermont Energy Act and has the consent of Vermont’s Public Service Board. Contracted rates are differentiated among the technology used, size of the technology capacity, and costs of production. Unlike all other renewable resources, methane developed from agricultural resources is not required to transfer the RECs created through the generation to the electric company.

CVPS Biomass Electricity Production Incentive: CVPS offers a production incentive to farms who own systems utilizing agricultural AD. CVPS purchases the electricity and RECs at 95% of the locational marginal price at market, plus an additional \$0.04/kWh. Eligible systems must be connected to the grid, and net metering is not available under this arrangement. CVPS sells the RECs received under this arrangement as part of CVPS’s Cow Power, the utility’s green power program.

6.4 Challenges

While Vermont has experienced great success in growing AD on farms, there are some challenges the state faces that limit the potential for growth in the near future.

- ◆ Limited number of large dairies
- ◆ Reduction in FIT price from \$0.16/kWh to an average of \$0.144/kWh may prevent farms on the margin for feasible size from building projects
- ◆ Constrained state budget making future grants potentially unavailable
- ◆ Difficulty connecting a generator to the electric grid in a rural area

6.5 Success Factors

In Vermont, renewable energy policy, political will, and strong leadership came together to create a model for success for the rest of the country. Primary reasons for this success are highlighted below:

- ◆ Economic viability from the FIT and CVPS Cow Power production incentive are the most significant single factor for the success of biogas in Vermont
- ◆ Customer buy-in from CVPS customers to pay a premium for renewable energy
- ◆ Ability of stakeholders to leverage policy opportunities to create programs favorable to environmental and renewable energy goals.
- ◆ State support and leadership from the utility industry for moving agricultural biogas forward
- ◆ Technical, regulatory, and financial expertise developed and shared across projects through CVPS Cow Power and the consultant, Agricultural Energy Services.



Dubois Farm in Vermont (Source: CVPS)

Chapter 7

Agricultural Biogas in California

7 Agricultural Biogas in California

7.1 Introduction

California is the state with the greatest potential market for biogas production, with 889 candidate farms (AgSTAR, 2010). Despite this, there are currently only 15 operational digesters and zero under construction in California. A table listing these projects is available in Appendix C. AgSTAR reports that 7 facilities have shut down and 6 facilities have been cancelled (3 of these were at the same dairy). The project shutdowns occurred largely because of air quality regulations that were not technically achievable at the time at a reasonable cost for moving a project forward; and possibly not attainable at any cost. Rather than build new projects or continue operating existing digesters, a number of existing projects closed and planned projects were cancelled. Despite California's potential to be the largest producer of agricultural biogas, attempts to grow the industry have met with mixed results, primarily due to low energy prices, challenges with obtaining permits, and difficulty complying with environmental regulations. This chapter provides an overview of the agricultural biogas industry in California, with particular emphasis on the permitting process and project funding and financing practices.

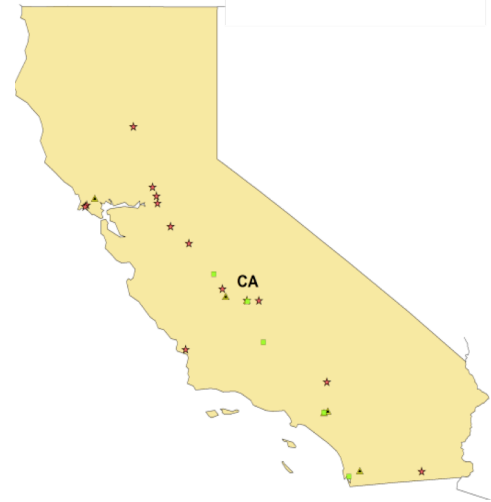


Figure 10 Anaerobic Digester Projects in California

7.1.1 Biogas in Practice

One of the primary drivers for an increase in the number of biogas facilities in California was the Dairy Power Production Program. For this program, 55 grant applications were received and screened, 14 were selected for funding, and 10 of those completed installation prior to August, 2006. The remaining 4 projects opted not to construct their digester systems due to fiscal concerns and withdrew from the grant program. The installed capacity of biogas facilities ranges from 25 kW to 700 kW on an individual project. Except for one project that flares the biogas full time, all other California digesters generate electricity either for on-farm use, connecting to the power grid, or both. Vintage Dairy had connected biogas directly to a natural gas pipeline at one time, but the project was terminated in 2009 due to design and technical failures.

7.2 Regulatory Framework

7.2.1 Water Permits

Background: The California permit program is operated through the California Environmental Protection Agency's (CalEPA) State Water Resources Control Board (State Water Board) and 9 semiautonomous Regional Water Quality Control Boards (Regional Water Boards), pursuant to 27 CCR § 22560. The California Water Code specifically prohibits any point source discharge from a CAFO within the state, and thus does not issue NPDES permits. The State does, however, issue Waste Discharge Requirement (WDR) Orders, which are state permits that require the development of NMPs and the submittal of annual reports.

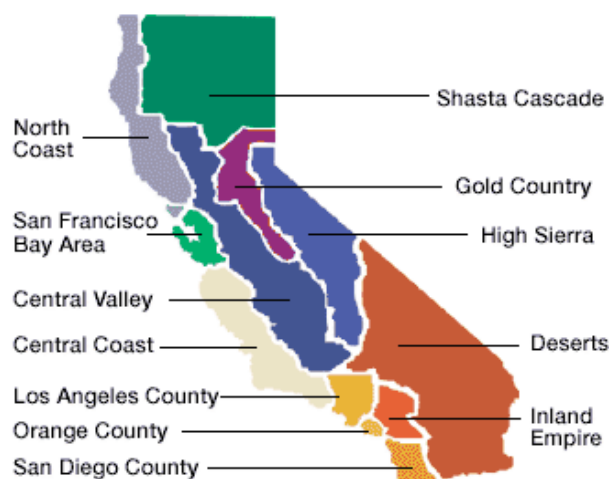


Figure 11 California Regional Water Board Jurisdictions
(Source: CA State Water Resources Control Board)

Because of the relative autonomy of the Regional Water Boards (Figure 11), regulations for CAFO sources of groundwater pollution are divergent. Some Regional Water Boards that have yet to address AD in their regulations continue to regulate it as a waste treatment process. Alternatively, to streamline the permitting process for ADs, CalRecycle and the Central Valley Regional Water Quality Control Board (Central Valley Water Board) regulate ADs

as recycling and require an environmental impact report (EIR) for all AD facilities. The EIRs are intended to reduce the cost and time needed to permit AD projects. Furthermore, the Central Valley Water Board also implemented some specific guidelines for permitting agricultural AD facilities through WDR Order No. R5-2010-0130 (CA Regional Water Control Board Central Valley Region Order No. R5-2010-0130/0). The State Water Board is also committed to developing clear and consistent procedures for regulating biomass – including biogas – production to protect water quality (State Water Board Resolution No. 2007-0059; Bioenergy Action Plan, 2011).

Compliance: A CAFO must file a Report of Waste Discharge (Form 200) with its Regional Water Board in order to obtain WDRs at least 120 days prior to discharging waste

(Appendix M). If the Regional Water Board proposes to issue the facility a permit, it will do so after a public comment period and public hearing. This process normally takes about 3 months. WDRs are in effect until a facility terminates or modifies its discharge. AFOs must only submit a filing fee with their Form 200 and are exempt from annual WDR fees.

7.2.2 Air Permits

Background: California has 14 AQCRs, which are divided into 35 air districts. All the districts operate under CARB, but are primarily autonomous. Each district enacts its own regulations to control the facility emissions within its area. Some counties have more stringent air quality standards than others, so the time period for receiving permits varies for all farms depending on the district – ranging from a few weeks to 18 months. The major issue that farm owners have with air quality is the NO_x emission standards for on-farm generators. Regional Air Boards are required by EPA to regulate NO_x emissions but not GHGs. Therefore, even if the AD facilities reduce GHG emissions, they still need to undergo the scrutiny of the NO_x standards. One consultant mentioned that her client had to find registered professionals in 5 different areas to work on 11 reports in order to get the project started. This process adds substantial cost to the process for farm owners.

Compliance: An AFO that seeks to modify its operations by construction an AD must submit construction and operation permit applications to its appropriate Air District.

7.2.3 Public Utility Connection

Generators who are not under the jurisdiction of FERC must comply with the regulations of the California PUC. The CPUC has adopted Rule 21, which specifies standard interconnection, operating and metering requirements for distributed generation systems up to 10MW, including renewables. Simplified rules for small renewables under 10kW exist, but only apply to solar photovoltaic and wind systems. Rule 21 requirements are very similar to the Fast Track Process established by FERC. California also has net metering for renewable-energy systems up to 1MW in capacity and includes provisions for time-of-use net metering. Significantly, net-metered systems up to 1MW are exempt from paying costs associated with the interconnection studies, distribution system modifications or application review fees, which they would otherwise be responsible for paying. For any of these regulations to apply, the generator must be located in the district of one of California's investor-owned utilities.

California utilities are also exploring the possibility of direct injection of biogas into the natural gas pipeline. In 2008, California utility PG&E launched the first renewable natural gas project in California together with Vintage Dairy. Although the project was terminated in 2009 due to technical failure, PG&E is still positive about the potential for renewable natural gas. Utilities SoCalGas and SDG&E have filed for authorization from the CPUC to develop, own, operate and maintain biogas production and gas conditioning facilities to produce pipeline quality gas.

7.3 Project Funding and Finance

7.3.1 In Practice

The economic viability of a biogas project largely depends on the price that a farmer can obtain for selling electricity generated through biogas production. On average, 47% of the installation cost is funded through outside sources (USDA, 2011). According to the farm owners interviewed, the most common funding sources have been USDA grants, the Dairy Power Production Program (DPPP), Section 319 Grants, and the Self-Generation Incentive Program (SGIP).

In California, the electricity buyback price received from utilities is not high enough to make AD viable on a number of farms. Prior to 2009, the net metering policy took the electricity transmitted to the grid as credits to offset the on-farm electricity consumption, while farmers were not paid for the excess electricity they produced. In addition, farmers sold power to utilities at generation price, but purchased power at retail prices. For example, in January 2006, energy rates under PG&E's AG-5C tariff ranged from \$0.053 to \$0.084/kWh, while the net metering credits ranged from \$0.022 to \$0.036/kWh.

The situation changed in 2009, when Governor Schwarzenegger signed AB 920 into law, requiring California utilities to compensate net metering customers for electricity produced in excess of the on-site load over a 12-month period. Despite this success, the price that utilities are paying for energy is still too low, according to some farmers. The price farmers receive varies, depending on the type of power purchase agreement they sign with utilities. Generally speaking, public utilities pay less than private utilities. One farmer reported being paid for electricity produced at a rate of only 50% of what he purchased electricity for from the utility. This farmer wanted to switch to a power purchase agreement

with a private utility in the neighboring county, but the wheeling charge imposed by the public utility made it infeasible for the neighboring utility to purchase power from his farm.

The On-Farm Renewable Energy Production Survey conducted by USDA in 2009 estimated that the average capital installation cost in California is about \$1.8 million per digester. The payback period on this investment is approximately 7 to 10 years. O&M costs for an AD and gas engine system can be as high as \$0.04/kWh, higher than the credit provided by PG&E's net metering tariff (Anders & Center, 2007).

On average, 47% of the installation cost is funded through outside sources (USDA, 2011). Although initial interest in the DPPP grant program was high, a number of farms dropped out of the process or did not receive grant funding. Some of the reasons for this reported by Western United Resource Development (2006) were:

- ◆ High level of financial obligation required/ low milk prices;
- ◆ Lack of interest;
- ◆ Technology did not qualify for buydown grants;
- ◆ Did not agree to terms of grant program;
- ◆ Permitting issues;
- ◆ Project completion timeline not feasible; and
- ◆ Amount of time and involvement required.

7.3.2 Financing Sources

Below is detailed information about California's primary government funding sources. This list is not exhaustive, and additional funding sources are listed in Appendix I.

Grants

Dairy Power Production Program (DPPP): Most digesters in California were built after 2004, due to the availability of DPPP funding at that time (DPPP, 2006). The California Energy Commission (CEC) established the DPPP grant. Two types of assistances were made available: buydown grants, which cover up to 50% of the capital costs of the

proposed biogas system (not exceeding \$2,000 per installed kW), and incentive payment grants to pay for electricity generated at \$0.057/kWh.

Section 319 Grant: Section 319 of the 1987 Federal Clean Water Act established a grant program to fund innovative nonpoint source pollution management strategies. The State Water Board administers the \$5 million grant program to help meet total daily maximum load limits in impaired watersheds. Historically, grants have been awarded in the range of \$25,000 to \$350,000 per project.

Production Incentives

Self-Generation Incentive Program (SGIP): The CPUC requires utilities to provide financial incentives to customers who install distributed generation under the SGIP program. Customers of four utilities were eligible to apply – PG&E, SCE, SoCalGas, and SDG&E. The program includes a tiered funding system, with Level 1 funding of up to \$4,500/kW for digester gas fuel cell systems (capped at 50% of the capital costs) and Level 3 for digester gas at \$1,5000/kW (capped at 40% of the capital cost). The program started in 2001 and ended in 2008, funding several farms.

Feed-in-Tariff: California requires that all investor-owned utilities and publicly-owned utilities with more than 75,000 customers make standard FIT contracts available to customers. Eligible customer-generators can enter into 10-, 15-, or 20-year contracts for the utility to buy the electricity produced by small renewable energy systems at time-differentiated, market-based prices. The renewable energy systems must be 3MW or less, and once the statewide capacity of eligible installed generators reaches 750MW, then the FIT will no longer be available. Because these contracts are intended to help utilities meet California's RPS, all green attributes of the energy produced, including RECs, transfer to the utility with the sale. Finally, any customer-generator who sells power to the utility under this program will not be eligible to participate in other state incentive programs. This model has not been as successful as Vermont's FIT.

7.4 Challenges

While California has an electricity generation potential of 2,375,000 MWh per year, it is currently nowhere near reaching that potential, and there are not a significant number

of projects coming online in the near future. The following challenges must be addressed in order for future growth to occur:

- ◆ Economic viability impeded by low price per kWh and wheeling charges;
- ◆ Constrained state budget and potential future unavailability of grants;
- ◆ Restrictive permits for codigestion limits energy potential in San Joaquin Valley;
- ◆ Prohibition on transport of waste off-farm limits potential for a cooperative business model; and
- ◆ Difficulty negotiating interconnection agreements.

7.5 Success Factors

Although the agricultural biogas industry has experienced a number of challenges and setbacks, there is reason to be optimistic about the industry's long-term growth in California. The key factors that will position California for success in the future are:

- ◆ Significant potential for growth with 889 dairy candidate farms;
- ◆ Support from the state for progressive environmental and renewable energy policy;
- ◆ Future carbon trading scheme could increase price of carbon credits, and drive biogas growth;
- ◆ Initial dedicated funding through DPPP;
- ◆ Recent improvement of net metering regulations; and
- ◆ Technical, regulatory, and financial expertise developed and shared across projects through consultants like AgPower Development, LLC.

Chapter 8

Agricultural Biogas in New York

8 Agricultural Biogas in New York

8.1 Introduction

New York's agricultural biogas industry¹ has substantial growth potential, but it is presently not as successful as the industry in neighboring Vermont. New York State has 216 candidate farms (USDA, 2007), but few farms are generating biogas with the waste they produce. Twenty-three (AgSTAR, 2010) farms have operational ADs, 5 have facilities under construction, 7 are in the planning phase, and 5 farms have decommissioned facilities (Scott et. al., 2010). A table listing these projects is available in Appendix C. The business model for biogas development in New York has not been as consistent as that in Vermont, as there are 2 digester design companies that are commonly used and that assist farmers through the production process. Farmers in New York use GHD, like Vermont, but also RCM Digesters, Inc. (Scott et. al., 2010). The most influential entity for the development of New York's biogas industry is the New York State Energy Research and Development Authority (NYSERDA). NYSERDA, a public benefit corporation, provides development guidance through information gathering and sharing, as well as funding to agricultural AD projects, but is not as successful as CVPS Cow Power at coordinating industry development. This chapter provides an overview of the agricultural biogas industry in New York, with particular emphasis on the permitting process and project funding and financing practices.

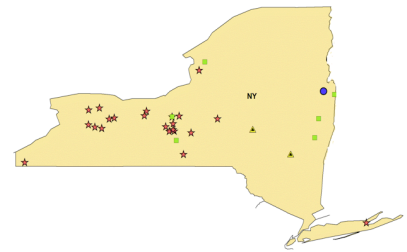


Figure 12 Anaerobic Digester Projects in New York

8.1.1 Biogas in Practice

The installed capacity of biogas facilities on dairy farms in New York ranges from 50kW to 500kW of electricity (AgSTAR, 2010). The primary motivation for farms to attempt to enter the AD market is to reduce odor from manure generated through farm operations, as well as create financial savings. Once ADs begin producing biogas, most farms use the produced energy on-site, and then sell any excess to the utility, often through net metering.

¹ The data in this chapter is not as comprehensive as the data in other chapters because New York farmers were either not as accessible or willing to participate in interviews as those in Vermont and California.

After New York farmers decide to develop a facility, they usually turn to NYSERDA for technical guidance and financial support. The public benefit corporation's entire mission is to help the State meet its energy goals, which include energy consumption reduction, renewable energy use promotion, and environmental protection. NYSERDA is funded largely through the Systems Benefits Charge imposed on in-state rate payers. It created New York Energy Smart, which directs funding towards efforts to develop competitive energy efficiency markets; to continue research, development, and demonstration; and to create tangible economic and environmental benefits to New Yorkers. NYSERDA also integrates various stakeholders into the renewable energy discussion. Governments, private sector, academic institutions, and those in environmental, energy, and public interest groups all participate in directing NYSERDA's policies. For example, Cornell University's Dairy Environmental Systems program has actually been integral in providing extensive research on farm-based biogas production for NYSERDA.

The least successful component of the biogas production market in New York is the O&M phase of development. The dairy farmers' area of expertise is in milk production, so incorporating an AD on site diverts the priorities of the farm's primary business because there is no O&M support industry in the State. Thus, farmers find themselves playing dual roles, one of which they are not well suited for. The absence of O&M businesses has made biogas production somewhat burdensome for farms and has stymied other farms' entrance into the biogas market.

8.2 Regulatory Framework

Prior to applying for any permit, a farm seeking to install an AD in New York must follow the State Environmental Quality Review (SEQR) procedures. Once the SEQR is satisfied, the owner or operator of a farm may submit its permit applications.

8.2.1 Water Permits

Background: The New York permit program is operated through the Department of Environmental Conservation's Division of Water Resources (NYSDEC) pursuant to 6 NY ADC 750 et seq. The State requires State Pollution Discharge Elimination System (SPDES) permits for point and nonpoint source discharges.

Compliance: The fee for CAFOs to obtain a SPDES Permit is \$50. If a CAFO does not propose to discharge, NYSDEC has established a SPDES General Permit (General Permit GP-0-09-001) (Appendix N). A facility seeking a General Permit must file a Notice of Intent to comply with the General Permit and a certified Comprehensive Nutrient Management Plan with NYSDEC at least 15 days prior to commencing operation.

8.2.2 Air Permits

Background: Under 6 NY ADC 201, New York State has 8 AQCRs, all varying in attainment level (Appendix O).

Compliance: The State requires that prior to any construction that would classify a facility as a new source, the facility owner must obtain a preconstruction permit, which permits the construction and operation of the new source. NYSDEC is required to make a decision on non-major permit applications within 45 days of receiving a complete application. The farm must then register the facility with the NYSDEC at least 30 days before operation commences. NYSDEC may require major source applicants to hold a public hearing prior to issuing a permit. If no hearing is held, NYSDEC makes its final decision on the application within 90 days of its determination that the application is complete. If a hearing is held, NYSDEC notifies the applicant, and the public, of a hearing within 60 days of the completeness determination. The hearing must commence within 90 days of the completeness determination. Once the hearing ends, NYSDEC must issue a final decision on the application within 60 days after receiving the final hearing record. Generally, NYSDEC makes a completeness determination within 15 days of receiving a permit application (6 NY ADC 621).

8.2.3 Public Utility Connection

The New York PUC oversees Standard Interconnection Requirements (SIRs) that apply to distributed generation systems of up to 2MW in capacity that are located in the service areas of New York's investor-owned utilities. Systems of up to 25kW, or certified inverter-based systems of up to 200kW, are regulated by a simplified 6-step process, whereas systems of up to 2MW are governed by a more in-depth, 11-step process. Each process has its own interconnection timeline, standards for who is responsible for interconnection costs,

and procedures for dispute resolution. Each procedure also covers the entire process from application filing, to actual interconnection. Furthermore, New York has a net metering system which was recently expanded to include farm-based AD facilities of up to 1MW. This system is overseen by NYSERDA.

8.3 Project Funding and Finance

8.3.1 In Practice

New York farmers depend on a combination of REAP grants, NYSERDA grants, AEM grants, and private farm loans to fund the installation and operation of their ADs. NYSERDA is by far the most influential state-level funding source, and assists with expenses related to purchase, installation, and operation of AD Gas-to-Electricity Systems. Capacity-based and performance-based incentives are offered by NYSERDA as well. In 2010, it offered \$10 million of funding for projects included agricultural AD (NYSERDA, 2010). Any combination of NYSERDA incentives can be obtained, up to \$1 million per AD system. Eligibility for funds is, however, limited to those customers who pay the RPS surcharge. Under Program Opportunity Notice 1146 (specific to AD systems), incentives for these types of projects are also known as “behind the meter” energy generation incentives.

The capital cost of developing a facility in New York ranges from around \$300,000 to \$4.5 million for dairy farms; varying by digester type, farm size, and technology designer (Scott et. al., 2010). The average installation cost for a New York facility is \$1.6 million, with about 36% of installation costs being funded by outside sources (USDA, 2009). Expenses are high enough for prospective biogas producers to seek all available funding at the state and federal level, but still must fund a substantial portion of the project themselves. NYSERDA reports that though many more farmers than are currently operating facilities are interested in producing biogas, and submit applications for funding, but many withdraw those applications due to the numerous roadblocks discussed above. The most prevalent recent roadblock has been low milk-prices, significantly cutting the profits of many producers, and causing a number of small-sized farms to close. Farmers also said that the prices offered by New York utilities, both to purchase the generated electricity and through net metering, are too low to make a project profitable. Finally, the burden of O&M often prevents farms from successfully operating AD facilities. Annual O&M costs were reported by some to range from \$24,000 to \$94,000, while annual benefits are limited to

\$13,000 to \$78,000.² Thus, the costs of operating an agricultural AD in New York tend to outweigh the benefits.

8.3.2 Financing Sources

Below is detailed information about New York's primary government funding sources. This list is not exhaustive and additional funding sources are listed in Appendix I.

Grants

AEM Agricultural Nonpoint Source (NPS) Abatement and Control Grant: This grant gives financial assistance to farmers for agriculture related water pollution prevention. Farmers must be represented by their County Soil and Water Conservation District to apply for the grant. The New York State Soil and Water Conservation Committee and the Department of Agriculture and Markets oversee the allocation of these funds on a semi-annual basis.

Production Incentives

RPS Customer-Sited Tier Regional Program: Beginning in March 2011, NYSERDA began offering incentives to biogas electricity generators larger than 50kW that are located in certain regions of the state. The program is part of the state's RPS program, and is funded by the RPS surcharge collected on the electricity bills of customers of the state's major investor-owned utilities. The State has a goal of meeting 30% of its energy needs through renewable resources by 2015, and has put NYSERDA in charge of implementing policies to reach this goal.

This incentive is based on expected and actual energy production. Eligible generators must apply to the program by submitting a bid to NYSERDA in the form of \$/kWh as an incentive request. The incentives are limited to 50% of the installed costs of the equipment and \$3 million per applicant per round. Projects that are selected to receive incentive payments receive both up-front payments and production payments according to a specific

² These statistics were obtained from Cornell Dairy Environmental Systems AD Case Studies, and represent different time periods that might not be representative of the entire New York market today. They are included, however, to give some reference point for costs.

schedule. The first payment is received when all major equipment has been transported to the site, the second payment is received when the project has connected to the grid and been proven capable of producing performance data, and the remaining payments are based on production. The amount of the payments will be based on a percentage of the incentive bid times the estimated energy production over the course of 3 years. Any selected applicant must conduct an energy efficiency assessment to identify possible improvement measures related to electricity use. Although only 2 funding rounds have been publicized thus far, the program has been approved through 2015.

Anaerobic Digester Gas-to-Electricity Rebate and Performance Incentive (Expired 12/31/2010): This program incentivized small sized electricity generation for the electricity to be used primarily at the electric customer's location. This program was designed with both a capacity and a performance based incentive, and was a part of the state RPS program. This program is unlikely to be renewed, because it has been replaced by the RPS Customer-Sited Tier Regional Program, and is only included here to explain the prior incentives in place for farm-based AD production.

8.4 Challenges

New York has a good framework to support the initial development and supportive research efforts needed to advance the agricultural AD market. The State is lacking, however, in effective funding incentives and support services once the AD systems are operational. Some of the greatest challenges to agricultural AD development in New York are:

- ◆ The price of energy sold to utility companies in New York is too low, especially when compared to the price sold to utility companies in neighboring Vermont;
- ◆ The lack of funding stability and potential future unavailability of grants; and
- ◆ The absence of O&M businesses.

8.5 Success Factors

The successes of the State's agricultural biogas industry lie heavily in the biogas industry research it has done and continues to produce. These efforts are grounded in the work of NYSERDA, and include:

- ◆ Research and monitoring being conducted by Cornell University's Dairy Environmental Management program;
- ◆ Efforts of NYSERDA to better incentivize farm-based biogas production;
- ◆ Discussion of creating an entity similar to Cow Power in Vermont

Chapter 9

Agricultural Biogas in Massachusetts

9 Agricultural Biogas in Massachusetts

9.1 Introduction

Massachusetts is unique among the states highlighted in this report, particularly because it currently has no operating ADs on farm sites. Massachusetts' number of candidate dairy farms as determined by herd size is quite small, with only 2 (USDA, 2007). With over 100 dairy farms having over 50 head of cows (USDA, 2007), however, the potential for increased cooperatives like AGreen Energy could expand the use of this form of renewable energy production throughout the State.

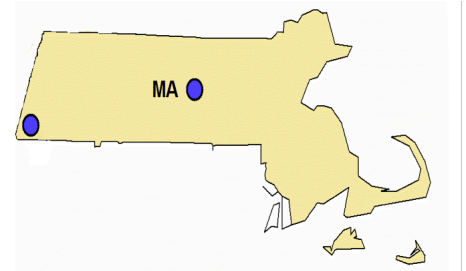


Figure 13 Anaerobic Digester Projects in Massachusetts

9.1.1 Biogas Industry in Practice

Through the Green Jobs Act of 2008, Massachusetts formed the Massachusetts Clean Energy Center (MassCEC) to expand the clean energy industry. It has served as a support agency to developers of renewable energy projects—like AGreen Energy who is developing the cooperative agricultural AD facility in central Massachusetts—by investing in new and existing companies. MassCEC also assists companies with accessing capital and resources for their business. In 2009, the Massachusetts' Renewable Energy Trust Fund, which is funded by rate-payers through a systems benefit charge of investor-owned utilities and participating municipal lighting plants, was transferred to MassCEC. AGreen Energy was able to acquire some funding for feasibility studies of their AD project from MassCEC.

AGreen Energy is a cooperative of five central Massachusetts farms, formerly the Massachusetts Dairy Energy (MADE) group, which has two of its five farms in the construction phase of development and should be operating the first agricultural AD facility in Massachusetts within weeks. Jordan Dairy Farm in Rutland spearheaded the initiative. Manure waste on the five farms will be combined with liquid food waste from food processors, restaurants, and grocery stores, and then be co-digested. The process of running a co-digester on each of the five participating farms has been a complex one, and the project is 10 years in the making.

The primary incentive for developing this project was manure management, reduction of GHGs, and financial savings. The undertaking took the collaboration of various entities, each playing a key role in making farm-based biogas production in Massachusetts

a reality. The designer Qausar Energy Group built the AD for Jordan Dairy Farms and in the past installed two for Ohio farms. The operator of the digester will be New England Organics, a division of the hauler and recycling company Casella Waste Systems.

9.2 Regulatory Framework

9.2.1 Water Permits

Background: Massachusetts is not an authorized state under the NPDES Program. Therefore, a farm seeking to construct an AD that would result in a point source discharge must submit an NPDES application to EPA.

Compliance: A CAFO proposing to discharge into surface water or to modify its operations by installing an AD must submit an application to EPA Region 1. Nonpoint source AFOs that are not required to obtain permits for such discharges, but must operate under established BMPs pursuant to 314 CMR 5.00 et seq.

9.2.2 Air Permits

Background: Under 310 C.M.R. 7.00 et seq, Massachusetts has five AQCRs. Massachusetts requires plan approval from the Department of Environmental Protection (MassDEP) prior to any construction, substantial reconstruction, alteration, or subsequent operation of a facility that may emit pollutants.

Compliance: A facility may submit a limited plan application (LPA) or a comprehensive plan application (CPA). All LPA and CPA approvals will require that a facility implement that best available control technology (BACT) in attainment areas, and the lowest achievable emissions rate (LAER) if the facility is in a nonattainment area. However, a facility seeking to install an AD system is not required to apply for an air pollution permit if it can show that the operation of such AD would decrease, or not contribute more to, the emission of contaminants from the facility. Source Registration is required of any person owning, operating or controlling a facility if it has the potential to emit at least 2 tons/year of PM, 2.5 tons/year of SO_x, 10 tons/year of VOCs, or 4.4 tons/year of NO₂.

9.2.3 Local Requirements

M.G.L. 40A § 3 may allow Massachusetts AD facilities that propose to accept organic waste from other facilities to avoid the zoning variance requirement. It prohibits any zoning ordinance from “unreasonably regulating” the use of land for the purpose of agriculture. The trigger word is unreasonable. Instead of being an outright prohibition, the law lets local zoning boards determine whether an AD facility would qualify as an agricultural purpose. This provision allows farmers to argue for an exemption.

The Jordan Dairy Farms collective is benefitting from collaboration between MassDEP and the Department of Agricultural Resources (MDAR). The facilities were approved for a complementary set of permits for air emissions (pollutants, noise, and odor), material receiving and processing, and fertilizer licensing. MassDEP interpreted the AD process as one that produces a product, rather than a process that stabilizes waste, thus allowing the facility to be regulated as a recycling operation, rather than requiring the regulation of a new category of waste treatment. (Snelling, 2010)

9.2.4 Public Utility Connection

Similar to California, the Massachusetts Department of Public Utilities (DPU) regulates the transmission of electricity for distributed generation systems, and to end users. For distributed generation systems, the Model Interconnection Tariff includes provisions for 3 levels of interconnection. Simplified interconnection is a 15-day process that has no fees. This is available for certified, inverter-based, single-phase facilities of less than 10 kW, and certified, 3-phase systems of up to 25 kW. A \$100 fee can be charged, however, if the proposed interconnection is on a distribution network circuit, to review the network protector’s interaction with the system. For this streamlined interconnection process, the aggregate generating facility capacity must be less than 1/15th of the customer’s minimum load.

If the facility does not qualify for the simplified interconnection, then the generator can apply for either “expedited” interconnection or will have to undergo “standard” interconnection review. Under the expedited interconnection procedures, both the time frames and fees to complete the interconnection are limited. Fees are set at \$3/kW of generator capacity, with a minimum fee of \$300 and a maximum of \$2,500. The DPU began the process of reviewing and amending this system in February 2011, so these standards

are not likely to be in effect much longer. For these standards to apply, the distributed generation system must be in the district of one of Massachusetts investor-owned utilities.

Massachusetts also has net-metering under the State Green Building Act, which allows customers with facilities up to 2,000kW in aggregate capacity to be eligible for connection.

9.3 Project Funding and Finance

9.3.1 In Practice

Massachusetts does not offer any financial incentives to encourage agricultural AD. Although AD is included in the state's RPS, all government-sponsored financial incentives are targeted at wind and solar power. One program implemented in Massachusetts that might financially incentivize the development of agricultural AD facilities in the future is the RGGI carbon trading program. Because of the lack of substantial financial state support for farm-based biogas production, AGreen Energy has had to rely primarily on the Federal level funding sources, such as USDA's REAP and EQIP programs to assist with the \$2.8 million capital costs of each farm's digester (Casella Waste Systems, Inc., 2011).

9.3.2 Available Financing Sources

Though Massachusetts does not directly provide incentives for agricultural AD, there are two funding sources that have potential benefits for the industry. These incentives, however, cannot both be used on any one project. This list is not exhaustive, and additional funding sources are described in Appendix I.

Grants

Agricultural Energy Grant Program (Ag-Energy): Ag-Energy provides funds to help Massachusetts farms become more environmentally and economically sustainable by transitioning alternative clean energy technologies. This grant places a priority on projects that involve implementing energy upgrades for existing infrastructure, but can also be used to invest in energy production including "bio-fuel production." There is a \$30,000 maximum award.

Agricultural Environmental Enhancement Program (AEEP): AEEP funding is intended to help farms adopt mitigation and prevention practices to avoid the negative environmental impacts that can be caused by their agricultural business. The focus of the improvement projects should be related to protecting water quality and/or conservation, air quality, or reduction of GHG emissions. An agricultural AD facility could qualify for this funding. The maximum award is \$30,000, though typical awards range from \$10,000 to \$15,000. Each award requires 5% matching funds from the project. The AEEP program funding is separate from the Ag Energy funding, however, it must be applied for through the Ag Energy Grant Program.

9.4 Challenges

There are many reasons that farmers have not successfully developed an agricultural AD facility in Massachusetts, the most significant being the following:

- ◆ Limited potential for growth (small number of “large” dairies);
- ◆ Lack of good information exchange system; and
- ◆ Limited funding opportunities for initial costs.

9.5 Success Factors

With Jordan Dairy Farms becoming operational in the near future, there is ample reason to hope that Massachusetts will continue to make efforts to jumpstart an agricultural biogas industry in the State. Some of the most promising evidence that Massachusetts will continue to make efforts to promote the development of this technology is:

- ◆ Beginnings of a cooperative to serve as an example for other interested farms;
- ◆ Full retail price is paid for energy sent to grid from distributed generation systems; and
- ◆ Key stakeholders throughout the state are currently convening conferences to streamline and coordinate the entire process.

Chapter 10

Nellie's Journey – A Roadmap for Agricultural Biogas Development

10 Nellie's Journey – A Roadmap for Agricultural Biogas Development

This chapter provides a general roadmap for a hypothetical farmer (Nellie) who wants to install an AD facility on her farm. This roadmap illustrates the process with broad strokes because every development will be different, and needs to be customized to the situation of the farm. The intent of this chapter is to acquaint the reader with the framework of the process that a typical farmer would experience when developing an agricultural AD facility on her property.

10.1 A Solution to the Problems?

Nellie the farmer owns a dairy farm with 1,400 cows in upstate New York. The operation of this farm has been causing her some grief. First, the manure gives off a terrible odor and the neighbors have started to speak out about it. Next, with revenue solely coming from the sale of milk, her costs of operation are beginning to deplete her total margin. Also, one of Nellie's biggest expenditures is the bedding for her cows and the fertilizer for her field, and paying for this is another source of stress. Finally, Nellie understands that farms are a big contributor to greenhouse gases and would like to limit the impact of her farm.

A friend suggested that Nellie install an AD facility because it could solve all of the above problems:

1. ADs are an effective manure management system that completely removes the odor from the manure;
2. ADs allow you to produce electricity, which you can not only use on your own farm, but potentially sell back to the utility; thus reducing her own utility costs and creating additional revenue;
3. ADs produce an effluent that can be used as fertilizer and bedding; this can also be used on the farm or sold to other farms, thereby reducing costs and generating revenue; and
4. By turning the manure into something more useful, ADs reduce the amount of GHGs the farm emits, potentially producing renewable energy or carbon credits; this is not only good for the environment but generates another potential revenue source because these credits have value. ADs also happen to be better for water quality.

5. As an added bonus, dairy farms with ADs tend to be healthier from a nutrient management and animal health standpoint.

Given all this, and after doing some initial research to determine if her farm might be able to support this technology, Nellie decided to move forward with the AD development on her farm.

10.2 Technology

Now that Nellie has decided to install an AD, she must determine what type of digester would work best on her farm. She has a few considerations to take into account. The AD should be compatible with her system of manure collection. It also should be developed for the type of animal waste being used as feedstock, as well as with adequate capacity for current and future farm operations. She must take into account that some ADs are weather sensitive and thus may not operate effectively during winters in New York. Nellie must consider the costs of the different digesters and choose a feasible option. Finally, the ease of operation of the AD should be considered in the context of who will be operating and maintaining the digester – Nellie or hired operators. After all these considerations, Nellie decides to go with a plug flow digester because it processes manure from dairy cows more efficiently than the other options, and will withstand New York's winters.

10.3 Funding

Nellie discovers that the plug flow digester amounts to approximately \$1.5 million in capital costs alone and that she will also have to pay soft costs and additional capital costs to connect to the grid. Nellie must now step back and look at the monetary side of things. First, Nellie needs to make sure this project is actually feasible. Will she have enough feedstock supply to run an AD efficiently? Are the farm's finances in good enough shape to take on such a venture? Second, Nellie should consider the potential benefits added from the AD system. Is it enough that the farm's electricity and heat would be covered through the AD's operation? Will she need to sell the output from the system as fertilizer or bedding to cover costs? Nellie does remember that decreasing the amount of several pollutants would provide a cleaner environment for her cows, resulting in healthier cows. Finally, Nellie must consider what access she has to different funding sources. With the

help of some knowledgeable friends, Nellie discovers a few government sponsored grants and credits available to her. She has also been put in touch with lenders willing to give her fairly favorable terms on a loan. Because Nellie is a savvy business woman in addition to a dairy farmer, Nellie has some money available to invest in the project as equity. Under these circumstances, Nellie determines that the project will be feasible to build and operate, and in the end will be a productive means of adding revenue sources to her business.

10.4 Permitting and Interconnection

At the same time that Nellie is determining whether the project is financially feasible, she must determine what additional government obligations she will be subject to by installing an AD. After working with a consultant and contacting a few state agencies, Nellie knows what she needs to do simultaneously with applying for loans and government funding. Nellie needs a pre-construction permit from the NYSDEC's Air Division and a discharge permit from the Water Resources Division. They want Nellie to describe the AD process and estimate the actual amounts of pollution that the AD process will release, before she can start building anything. Nellie, correctly assumes that the studies needed to get this information will impose substantial upfront costs. Because Nellie does not plan to accept offsite waste, she fortunately does not need a zoning variance from the local government. However, she decides to contact the municipality anyway, since she must comply with the building code and could use their support.

Finally, Nellie determines that if she wants to make money off of the AD process she will need to sell the product of the process. So that she could sell the solid output as fertilizer and bedding, Nellie applied to the State Agency of Agriculture and Markets. So that she would have the opportunity to sell the electricity, she placed her name in the utility interconnection queue. Nellie also made a mental note to discuss the government mandated safety and reliability standards for utility connection with her contractor.

After about a year, with permits in hand, Nellie is able to begin construction of her AD, though she is still waiting on review of her utility interconnection request.

10.5 Construction, Operation, and Maintenance

In the process of building the AD, Nellie sees with her own eyes the complexity of the system and she decides to hire some technical assistance services. She contracts with the company to have them operate and monitor the AD, as well as address any machine failures. Nellie also requests that the operators keep track of the quantitative data reported by the AD for her to oversee the process' production. Nellie is now exploring ways that she can get in touch with other owners and operators of agricultural ADs, because she knows that there is a wealth of knowledge out there that she would benefit from being connected to.

Now that the AD is up and running, Nellie is producing fertilizer and bedding with lower pollution concentrations, she is making money from the sale of such effluent, and she has mitigated the odors and now can have her neighbors over for lemonade. Nellie is still waiting for approval of her interconnection request, though, and is nervous that she will not be able to enter into a contract with her local utility because NY does not have a FIT. Overall, though, Nellie has had a successful, be it long and expensive, process and is happy with her AD.

Chapter 11

Lessons Learned and Recommendations

11 Lessons Learned and Recommendations

11.1 Lessons Learned

An examination of agricultural AD in 4 states with different policies and levels of success in agricultural AD development provides an opportunity to understand some of the common challenges and drivers of success that influence the development of AD projects in a state. This section presents key findings from the examination of the national biogas landscape and the in depth look at the development of agricultural biogas in Vermont, California, New York, and Massachusetts. Also provided are targeted recommendations based on these findings. The findings discussed in this report highlight the significant challenges the U.S. faces in attaining a well-developed biogas industry comparable to that of Germany.

An extensive review of existing research and interviews with farmers and other stakeholders revealed the primary motivation for on-farm AD biogas projects to be odor reduction, cost savings from bedding production, and a secondary source of revenue from electricity generation. While these may result in direct benefits for the farm, these alone are not significant enough to compel substantial project development given the significant investment of time and resources required for development and interconnection. In addition to the direct benefits to the farm, there are also important societal benefits that accrue from the reduction of methane, CO₂, water and air pollutants, and improved waste management. These societal benefits, however, are not benefits that farms will pay for themselves – these are merely co-benefits. Because there are such positive externalities associated with developing agricultural AD, there is a strong rationale for continued public support and investment in AD development and, more generally, programs that provide monetary compensation for those who produce these environmental benefits.

An important feature to notice when considering how biogas can achieve its energy production potential in the U.S. is the different level of attention given to the agricultural biogas industry in a given state. As demonstrated by the 4 state case studies, it is the differences in policies, programs, and political will across states that have led to differences in the number of farm-based AD projects. This is true regardless of the overall production potential in the particular state. For a state to encourage development of agricultural AD projects, it must turn greater focus towards the energy potential of its agriculture industry, and enact strong renewable energy policies that are explicitly inclusive of, or specific to, biogas production. Even though state policy drives growth, it is also important to have a federal framework that supports the states' efforts to encourage renewable energy development generally.

Finally, based on current costs, anaerobic digestion is not economically feasible without public support through grants, loans, high electricity rates, as well as an agricultural sector in good economic health. As discussed in this report, for a digester to be economically feasible, a farm must aggregate funding from public programs, commercial lenders, and equity for a digester to be economically feasible. Some of the farms that were early adopters of AD technology experienced difficulty in securing financing from commercial lenders because of uncertainty about the technology and project risks. Though securing private financing remains a barrier, the primary financing challenge is tied to the lack of a stable, long-term revenue source.

11.2 Recommendations

Creating stability and predictability through market and regulatory policies and incentives is paramount to achieving successful future development of the U.S. agricultural biogas market. The following recommendations, based on the research conducted for this report, if implemented by the relevant members of the biogas community, would remove a number of the economic, regulatory, and technical barriers to development, and increase the growth of agricultural AD across the U.S.

11.2.1 Stabilize Funding

First and foremost, farmers must be guaranteed a stable source of long-term revenue for the electricity they generate. This is most successfully accomplished through implementing a FIT, because this measure mitigates merchant risk, and attracts investors and relatively low-cost financing by securing future revenue streams. Vermont created such a market through the Standard Offer Program, and institutionalized support for this program through CVPS Cow Power aided Vermont's development of biogas facilities.

To further encourage biogas production, uncertainty related to public financial incentives should be eliminated. Uncertainty currently exists, not only because generators are unsure if they can sell their electricity, but because many government subsidies are only enacted for a short period of time. Although they frequently get reauthorized, developers, lenders, and investors have no assurance of this, and therefore cannot trust that funding will be available when they need it. Further instability exists in government funding because grant funding is easily depleted. Because these programs quickly run out of money, there

is no continuous momentum driving more farmers to enter the market – they simply do not trust that the grants will be available. This problem could be alleviated by ensuring greater appropriations or endowments of money to the grant programs, or by shifting the focus of AD funding to other mechanisms, such as a FIT or tax credits. When grant programs are funded, there should be certainty incorporated into the grant cycle timeline, which is not currently true of USDA’s Rural Development REAP grant.

It is also important that the grants allow the farmer’s flexibility and avoid limiting development potential. As of now, after applying for a REAP grant a farmer cannot transfer the grant to an investor without re-applying for the grant. Allowing a grant recipient to be an equity contribution to a new investment would provide more flexibility from a financial standpoint. Another flexibility mechanism is to stop prioritizing projects based on whether or not they apply for the REAP loan guarantee, as not all financial institutions prefer this lending mechanism, so some farms may not apply for it.

Finally, federal and state tax credits are a primary driver of renewable energy production for wind and solar energy – which are currently more successful industries than agricultural biogas. Currently, some tax credits apply only to wind and/or solar energy, but many also do include biogas. However, those pursuing biogas projects do not know that tax credits are available to them, or do not want to deal with the burden of navigating the tax code. To help biogas projects take advantage of these opportunities, it is important to ensure that incentives can actually be used for biogas development, and if so, that an explicit reference to biogas be included in the legislation or program. Additionally, AgSTAR or another consultant should make a concerted effort to inform candidate farms for AD development that they can, and should take advantage of these tax credits by exploring the possibility of funding projects through outside investors, and providing support services for helping farms understand the tax credit options in the tax codes.

Finally, increased predictability through policies that reduced the price volatility of carbon could increase the use of environmental attributes for project revenue, increase the value of carbon credits, and increase the feasibility of these revenue sources for smaller farms that otherwise are impeded by the high upfront development costs.

11.2.2 Clarify Permitting and Agency Coordination

Environmental permitting and regulation is currently divided into particular issues (air, water, nutrient management, etc.). As a result, projects are not looked at holistically

for their overall environmental and health benefits. Additionally, the punitive nature of these policies does not encourage or facilitate the development of these environmentally beneficial projects, and in most states, the lack of coordination between the agencies and actors involved in permitting adds additional complexity to an already confusing process. Finally, in many cases, the regulations do not refer specifically to agricultural AD in any way, and it is unclear what type of activity agricultural AD will be classified as. To help overcome this challenge, states should develop permitting regulations specifically addressing AD and encourage coordination between key players across the various agencies. Of all of the case studies, California demonstrated the greatest challenges. By simplifying the ability to obtain co-digestion permits, California could significantly increase the energy output of current and future AD facilities. Also, by allowing the transport of waste off farms as an agricultural use, California would enable smaller farms to form cooperatives such as the Dane County community digester or the Massachusetts cooperative. Another opportunity for improved coordination exists within USDA's funding processes. Coordination of grant cycles and project component eligibility, such as EQIP for manure management systems and REAP for the AD technology, could encourage greater development.

11.2.3 Improve Knowledge Collection and Sharing

As the U.S. biogas industry has developed, so too has the knowledge and experience of farmers, environmental and energy consultants, technology vendors, and lenders. Rather than re-inventing the wheel, it is important to take advantage of this wealth of existing information generated from the U.S., as well as international AD industries. Crucial to this recommendation is the need to make collecting and gathering information throughout project planning, implementation, and operation a priority. While data collection and monitoring add expense to a project, the information it produces is essential both for the success of the project, for future research and development efforts, for data-driven advocacy, and for policy making. Another way to encourage information sharing is through the compilation of a clear, technology "catalogue" that would help interested farms that are new to AD understand their options, and then choose the machine that best suits their needs. This system currently exists in Germany and Israel. This catalogue, however, should be a complement to existing channels of knowledge sharing, rather than a substitute.

11.2.4 Continued Research, Development, and Innovation

As high capital, maintenance, and construction costs remain one of the most significant challenges to AD facility development, it is important that manufacturers and industry stakeholders continue to support advances in technology that reduce the cost of AD and improve the economic feasibility of smaller-scale projects. Because the cost and time required to keep a digester operating remains high, and a lack of maintenance was cited as the primary cause of a number of AD facility closures, it is also important that the industry find ways to reduce the resources required for O&M, and the time investment of the farmer. This can be done through improving and reducing the cost of remote monitoring and control mechanisms. As the industry grows, it would also be helpful to take advantage of expertise and economies of scale by creating service crews to handle the O&M of these facilities and alleviate the burden on the farm's resources. Finally, research should continue towards improving the technology and economic feasibility of alternative uses of biogas and its byproducts, such as gas cleaning for interconnection with the natural gas grid, cleaner engines such as microturbines and fuel cells, and the generation of transportation fuels.

Chapter 12

Conclusion

12 Conclusion

Ultimately, a well-developed biogas project and well-developed agricultural biogas industry has the potential to deliver very real environmental, economic, and energy security benefits to the United States as part of a multifaceted approach to transitioning away from fossil fuels towards renewable energy technologies. Simultaneously, this transition would improve the management of existing sources of waste and pollution on this nation's farms.

The U.S., however, has a long way to go before the market potential for biogas is realized, and this cannot be achieved without supportive regulatory and market policies. Of particular importance is the guaranteed ability of biogas generators to sell their electricity, as well as creating environmental attributes that provide long-term revenue security. Further, it is worth noting that while the market potential for dairy and swine presented in this report may appear relatively low, these numbers reflect current technological ability, and can be increased through research and innovation. Also, the inclusion of agricultural biogas into renewable energy policy and incentives will not just promote AD on farms, but also at landfills, wastewater treatment facilities, and food processing plants; thus expanding the potential of biogas to make a substantial renewable energy contribution.

As currently situated, the benefits of developing agricultural AD facilities are substantial, but the risks and costs associated with this technology in the U.S. are still too high to make this development realistic. Both the federal and state governments must intervene more aggressively than they have to make the potential U.S. agricultural biogas market a reality. Finally, these governments should intervene more aggressively than they have because the long-term benefits of such action will only serve to make the national energy market and the global environment safer and stronger for future generations.

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STATUTES & REGULATIONS

Federal:

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Appendices

Appendix A:

Biogas Technology Factsheet

- **What is biogas?**

Biogas is produced from the anaerobic digestion of organic matter such as animal manure, sewage, and municipal solid waste. It is typically made up of 50-80% methane, 20-50% carbon dioxide, and traces of gases such as hydrogen, carbon monoxide, and nitrogen (US Department of Energy 2011). Biogas can be used for all applications designed for natural gas. It can be used to generate electricity, sometimes in combined heat and power plants with electrical efficiency up to 41% (International Energy Agency 2005). It can also be upgraded (i.e., removal of water vapor and sulphide) and utilized as vehicle fuel, which uses the same engine and vehicle configuration as natural gas. Biogas can also be integrated into natural gas grid, which usually requires 97% methane content. Therefore, there is considerable difference between the requirements of stationary biogas applications and fuel gas or pipeline quality.

- **What is anaerobic digestion?**

In the absence of oxygen, anaerobic bacteria will ferment biodegradable matter into biogas in a series of processes. This process occurs naturally in the bottom sediments of lakes and ponds, in swamps, intestines of ruminants, and even in hot springs. It is now widely applied to produce biogas.

A variety of factors affect the rate of digestion and biogas production. The most important is temperature. Anaerobic bacteria communities can endure temperatures ranging from below freezing to above 135°F (57.2°C), but they thrive best at temperatures of about 98°F (36.7°C) (mesophilic) and 130°F (54.4°C) (thermophilic). To optimize the digestion process, digesters must be kept at a consistent temperature, as rapid changes will interrupt bacterial activity. In most areas of the United States, digestion vessels require some level of insulation and/or heating. Some installations circulate the coolant from their biogas-powered engines in or around the digester to keep it warm, while others burn part of the biogas to heat the digester. In a properly designed system, heating generally results in an increase in biogas production during colder periods. Other factors, such as pH, water/solids ratio, carbon/nitrogen ratio, mixing of the digesting material, the particle size of the material being digested, and hydraulic detention time also affect the rate and amount of biogas output.

- **What are the primary sources of biogas?**

Farm-based digesters - Daily operation of farms can provide stable feedstock for biogas production. While the main feedstock for farm-based digesters is manure, other organic matter,

such as food industry wastes and crop residues can also be processed in a digester. The main farm digester designs are covered lagoons, plug-flow, and complete-mix designs. An anaerobic lagoon is usually constructed by excavating and building an embankment around the top edge. They are usually covered with synthetic fabric. Since lagoons cannot be heated, this kind of digester relies on ambient temperatures. Therefore, covered lagoons are only feasible in moderate to warm climates, which generally fall below the 40th parallel in the U.S. (Ogejo et al. 2009). A complete-mix digester is a mechanically mixed unit with constant volume and controlled temperature. It is designed to process slurry manure with a solids concentration of from 2% to 10%. The digester contents should be continuously or intermittently mixed to increase contact between bacteria and substrates. A gas collection and utilization system is connected and a supplemental effluent storage is usually required. This system is considered to be the most robust in terms of the variety of manures that can be processed (Ogejo et al. 2009). A plug-flow digester is typically a covered long reactor where the manure enters at one end of the reactor and exits at the opposite end. It works best for dairy manure with 11% to 14% total solids. Since there is no mixer, a plug-flow digester is subject to stratification. In general, a horizontal plug-flow digester's length to width ratio is between 3.5:1 and 5:1 (Ogejo et al. 2009). As of November 2010, EPA AgSTAR program estimates that there are 160 anaerobic digester systems operating at commercial livestock farms in the United States. Of these operational projects, 140 generate electrical or thermal energy from the captured biogas. The electricity projects produce about 396,000 megawatt-hours (MWh) annually, and boiler projects, pipeline injection, and other energy projects generate an additional 56,000 MWh equivalent per year. Other projects fare the captured gas to reduce methane emissions and control odor (EPA AgSTAR 2010).

Landfill - Landfill is another source of biogas, which is generated by the anaerobic digestion of organic matters in buried garbage. To collect the biogas, landfill gas wells are drilled and pipes from each well carry the gas to a central point where it is filtered and cleaned before burning. Biogas taps one of society's least desirable items, garbage, and turns it into a useful, high-value energy producer.

Wastewater Sludge - The use of sludge from wastewater treatment plants (WWTPs) to generate energy is common in the U.S. Sewage sludge here contains a high percentage of biomass – electricity produced by 1 ton of sewage sludge is about 10 MWh, which is about four times of energy produced by 1 ton of coal (Biofuelsb2b 2007). Historically, the main incentive for using digesters to treat wastewater sludge was to reduce the volume of sludge, thereby reducing the cost of transporting and treating the sludge. The recognition that the methane produced by the digesters could be a significant source of useful energy is more

recent. Subjecting sludge to anaerobic bacteria in a digester can produce biogas consisting of approximately 60% methane and 40% carbon dioxide.

- **What are the benefits of biogas?**

Primary Economic Benefit of Biogas - Expenditure will be saved by the substitution of other energy sources with biogas and the substitution of mineral fertilizers with bio-fertilizer. Cost will be saved in disposal and treatment of substrates (mainly for wastewater treatment). And time will also be saved from collecting and preparing for fossil fuel materials and spreading manure.

Improving Hygienic Situation - Biogas plants serve as methods of disposal for waste and sewage and in this way directly contribute to a better hygienic situation for individual users. By collecting dung centrally, open storage is avoided. Apart from this, pathogens are extensively eliminated during the digestion process. All in all quite an improvement of sanitation and hygiene is achieved and therefore a biogas plant can contribute to a higher life expectancy.

Reducing Greenhouse Gases - Using biogas (primarily methane) to produce energy can reduce the risk to the environment that would otherwise result from natural decomposition. The reduction of 1 kg methane is equivalent to the reduction of 25 kg CO₂ in terms of global warming potential. Digesting 1 cubic meter of cattle manure can produce 22.5 cubic meter of biogas, which can generate 146 kWh of electricity and avoid 36kg equivalent CO₂ emission (Kossmann, Habermehl, and Hoerz 1999).

Protecting Water Bodies - Livestock manure generated at feedlots and dairies poses a risk of surface and ground water contamination from runoff. Microorganisms such as salmonella, brucella and coliforms in manure can transmit disease to humans and animals. Anaerobic digestion of manure destroys most of these microorganisms and protect water bodies.

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Appendix B:

Interview Guide

Farm-Based Biogas Production Market Interview Guide

Hi, my name is _____ and I'm a graduate student at Tufts University, in the Urban and Environmental Policy and Planning department working on a field project on farm-based biogas production. I am contacting you because you are listed in the AgStar on-farm biogas project database as a farm that is currently operating or constructing a biogas production facility. Some of my peers and I are conducting interviews with farmers with on-site anaerobic digesters, so that we can learn from your experience, which will be greatly helpful to both our academic endeavors and our hope of facilitating greater on-farm biogas production in the United States, with the ultimate goal of benefiting your role in the industry and the industry as a whole.

The information we collect will be used to evaluate farm-based biogas production processes, capacity, and trends throughout the country in order to compare data and recommend best practices. This interview should take no more than half an hour of your time and the collective results of it will be used to bring increased nationwide attention to on-farm biogas production. We understand that you are busy; so we'll try to not take too much of your time.

Your participation in this interview is completely voluntary. Your responses will be combined with those of others to produce summaries and reports, and your personal information, such as your name, will not appear in any of the reporting of the data.

Farm-Based Biogas Production Market Survey

Interviewee Name: _____

Farm Name: _____

Farm Background

I'm going to start off by asking you a few general background questions about the farm.

1. What Type of farm do you have?

☐ Dairy ☐ Swine ☐ Poultry ☐ Other ☐ Multi-use Please specify: _____

2. Could you please tell me what type(s) of animals you have and the head count by type?

3. Since what year has your farm been in operation?: _____

Background on Biogas System, Technology, & Operations

The next few questions will be about biogas production and the technology used on your farm.

4. Could you please describe your primary reasons for building an AD?

☐ Odor control ☐ Run-off control ☐ GHG reduction ☐ Cost savings ☐ Additional revenue stream ☐ Self sufficiency ☐ Other: _____

Additional Open-Ended Reasons: _____

5. In what year did you begin biogas production? _____

6. How much labor time and of what types does your biogas production facility require? ____

7. How many AD do you have at [farm name]? _____

8. What type of digester(s) do you have on the farm? (check all that apply):

☐ Complete-mix digester ☐ Plug flow digester (horizontal; vertical; mixed) ☐ Covered lagoon ☐ Fixed film digester ☐ Batch digester ☐ Blanket reactor ☐ Other:

9. What are the end use(s)?: ☐ Electricity generation (isolated power production for on-site use; parallel power production) ☐ Direct combustion (for heating; for chilling/refrigeration) ☐ Other: _____

10. What type of manure: ☐ Liquid (<5%) ☐ Slurry (5%-10%) ☐ Semi-Solid (10%-20%) ☐ Solid (>20%)

11. Do you supplement biogas production with any additional feedstock(s)? (e.g. food waste, waste water from food processing): _____

12. Could you please describe the process you went through to have the biogas facility built? (e.g.,

☐ Self-developed (farm owner hires a consultant, plans and manages the design-construction effort, and maintains ownership control of the project. This approach maximizes economic returns to the owner, but also places most of the project risks on the owner (e.g., construction, equipment performance, financial performance)

☐ Turn-key option (owner selects a qualified development company to provide the owner with a “turn-key” digester plant, which is built by the developer but owned by the farm owner)

☐ Partner option (owner teams with an equipment vendor, engineering/procurement / construction (EPC) firm or investor to develop the project and to share the risks and financial returns).

Additional Description: _____

12a. Who was the system designer?: _____

12b. Who was the system installer? _____

13. What is the installed capacity? (in the unit of kW or m³/hr if biogas is not converted to electricity)? _____

14. What is the capacity factor (that is, the number of kilowatt-hours delivered during a period divided by the product of (the maximum one hour delivered capacity in kilowatts in the period) times (the number of hours in the period)): _____

15. Do you recover waste heat from the system? ☐ Yes ☐ No If yes, to what end? _____

Project Costs

Because one of the goals of this project is to get a better understanding of how farms have implemented biogas projects, this next set of questions is about funding and finance issues related to the project.

16. Could you please briefly explain your initial strategy for securing project funding and finance? _____

17. What resources did you use to help with project funding and finance? _____

18. What public sources (grants, incentives, loans) did you to finance the project? How much of the money did you obtain from each of these sources?

19. What private sources (debt, equity, investment, lenders, cooperative financing) did you to finance the project (fund sources). How much of the money did you obtain from each of these sources?

20. What was the installation cost? _____

21. What was the total project capital cost? _____

22. What are the annual recurring operations and maintenance costs?:

23. Are there any other significant costs that haven't been mentioned?

24 What sources of revenue do you have from biogas production?

24a. Over the past 5 years, on average, has biogas production:

☐ been profitable ☐ allowed you to break even ☐ been a loss

24b. If profitable, what is your revenue, payback, and rate of return)

25. Do you have a contract with a utility? If yes, with whom and what type?

Utility: _____

☐ Buy all - sell all (utilities sell the farm all electricity requirements and then buy all the generator output)

☐ Surplus sale (a farm produces electricity in parallel for use on farm. Excess production is sold at avoided cost and excess consumption is purchased at the retail rate)

☐ Net metering (the generator output is offset on a monthly or yearly basis against the farm consumption with surplus production purchased by the utility or shortages purchased by the farm)

Obstacles

I'd now like to spend a bit of time talking about some of the barriers and challenges you've faced in the design, installation, and operation of a biogas facility.

26. What are the primary technical problems and/or barriers have you encountered in installing and operating the anaerobic digesters and related equipment?

27. What are the primary challenges you experienced in financing your biogas production: _____

28. Have you experienced any difficulty in selling energy to a utility :

Permitting

One of the other components of this project is a review of regulatory barriers. These next 3 questions address the regulatory and permitting process.

29. How long did it take for you to get all the required permits for the project: _____

30. What permits or authorizations did you need to receive from your local (municipal) government in order to proceed with developing this AD facility: _____

31. Does any part of the permitting process stand out as being particularly challenging? Please explain: _____

Wrap up

32. What recommendations/improvements would you make for streamlining/improving the process? _____

33. Is there anything we haven't talked about that you think is important for someone going through a similar process to know about? _____

Those are all the questions we have. We greatly appreciate your participation and thank you for taking the time to help us with this project. Feel free to get in touch with us if you want to add anything to what you've said, or amend any of your statements. Again, thank you again for your time, and have a great day!

Appendix C:

Anaerobic Digester Projects in Case Study States

Vermont

Status	Farm/Project Name	County	Digester Type	Year Operational	Farm Type	Population Feeding Digester	Co-Digestion	Biogas End Use(s)	Installed Capacity (kW)	System Designer	Methane Emission Reductions (metric tons CO ₂ E/yr)
Operational	Blue Spruce Farm, Inc. - Digester 1	Addison	Mixed Plug Flow	2005	Dairy	1,100	whey (two loads per week)	Electricity	240	GHD, Inc.	1,409
Operational	Foster Brothers Farms	Addison	Horizontal Plug Flow	1982	Dairy	380		Electricity	125	Hadley and Bennett	487
Operational	Footo Farm	Chittenden	Modular Plug Flow	2005	Dairy	160		Electricity	20	Avatar Energy	
Operational	Nordic Farm	Chittenden	Vertical Plug Flow	2005	Dairy	250		Cogeneration	350	Experimental glass / steel (Harvester Silo)	
Operational	Green Mountain Dairy, LLC	Franklin	Mixed Plug Flow	2007	Dairy	1,050	foodwaste (from Nearby Ben & Jerry's Plant)	Cogeneration	300	GHD, Inc.	1,345
Operational	Gervais Family Farm	Franklin	Mixed Plug Flow	2009	Dairy	950		Electricity	200	GHD, Inc.	1,217
Operational	Montagne Farm	Franklin	Mixed Plug Flow	2007	Dairy	1,200		Cogeneration	300	GHD, Inc.	1,537
Operational	Pleasant Valley Farms - Berkshire Cow Power, LLC	Franklin	Mixed Plug Flow	2006	Dairy	1,950		Cogeneration	600	GHD, Inc.	2,498
Operational	Maxwell Farm / Neighborhood Energy, LLC	Orleans	Mixed Plug Flow	2008	Dairy	750	Waste food products (waste grain, waste dairy products, waste crops, crops grown specifically for use in digester)	Electricity	225	GHD, Inc.	961
Operational	Chaput Family Farms	Orleans	Complete Mix	2010	Dairy	2,100	Agricultural Substrates (waste grain, food waste, waste dairy products, waste crops, or crops grown specifically for digester)	Cogeneration	300	RCM International, LLC	7,603
Operational	Westminster Farms	Windham	Mixed Plug Flow	2009	Dairy	1,200	Agricultural substrates (waste grain, food waste, whey, crops, manure from neighboring farms)	Cogeneration	225	GHD, Inc.	1,537
Construction	Blue Spruce Farm, Inc. - Digester 2	Addison	Mixed Plug Flow	2010	Dairy	1,100	whey (two loads per week)	Electricity	240	GHD, Inc.	
Construction	Monument Farms	Addison	Unknown	2010	Dairy	400		Cogeneration		GHD, Inc.	
Construction	Dubois Farm	Addison	Mixed Plug Flow	2010	Dairy	1,200				GHD, Inc.	
Construction	Four Hills Farm	Addison	Mixed Plug Flow	2010	Dairy			Electricity		GHD, Inc.	
Construction	Auburn Star Farm	Essex	Unknown	2011	Dairy	430		Electricity			
Construction	Kane's Scenic River Farms	Franklin	Mixed Plug Flow	2010	Dairy			Electricity		GHD, Inc.	
Cancelled	Boucher Farm	Franklin	Unknown		Dairy	250	crops and waste food products	Electricity			

California

Status	Farm/Project Name	County	Digester Type	Year Operational	Farm Type	Population Feeding Digester	Co-Digestion	Biogas End Use(s)	Installed Capacity (kW)	System Designer	Methane Emission Reductions (metric tons CO ₂ E/yr)
Operational	Vintage Dairy	Fresno	Covered Lagoon	2008	Dairy	5,000		Pipeline Gas		BioEnergy Solutions	26,544
Operational	Bullfrog Dairy	Imperial	Covered Lagoon	2008	Dairy	3,300		Electricity	300	RCM International, LLC	17,519
Operational	Strauss Family Dairy	Marin	Covered Lagoon	2004	Dairy	200		Cogeneration	25		525
Operational	Bob Giacomini Dairy	Marin	Covered Lagoon	2009	Dairy	300	Waste water (from cheese plant)	Cogeneration	80	Williams Engineering Associates	1,593
Operational	Blakes Landing Dairy	Marin	Covered Lagoon	2004	Dairy	362		Electricity	75	Williams Engineering Associates	1,639
Operational	Cottonwood Dairy	Merced	Covered Lagoon	2004	Dairy	5,000	wastewater (warm clean up water from cheese plant)	Cogeneration; Boiler/Furnace Fuel	700	Williams Engineering Associates	26,544
Operational	CAL-Denier Dairy	Sacramento	Covered Lagoon	2008	Dairy	900		Electricity	65	RCM International, LLC	3,983
Operational	Tollenaar Holsteins Dairy	Sacramento	Complete Mix	2008	Dairy	1,895		Cogeneration; Boiler/Furnace Fuel	250	RCM International, LLC	7,248
Operational	Meadowbrook Dairy	San Bernardino	Horizontal Plug Flow	2004	Dairy	2,000		Electricity	160	RCM International, LLC	279
Operational	Castelanelli Bros. Dairy	San Joaquin	Covered Lagoon	2004	Dairy	3,214		Electricity	180	RCM International, LLC	12,588
Operational	Cal Poly Dairy	San Luis Obispo	Covered Lagoon	1998	Dairy	175		Electricity	30	RCM International, LLC	929
Operational	Fiscalini Farms	Stanislaus	Complete Mix	2008	Dairy	2,513	Cheese whey, sudan grass, and residuals (30 tons/day sudan silage, 20 tons/day whey)	Cogeneration	720	Biogas Energy, Inc. (Biogas Nord System)	5,343
Operational	Hilarides Dairy	Tulare	Covered Lagoon	2004	Dairy	1,500		Electricity; Vehicle Fuel	750	Sharp Energy; Phase 3 Renewables	1,918
Operational	Laurenco Dairy	Tulare	Covered Lagoon	2006	Dairy	2,640		Flared Full Time		Sharp Energy	7,364
Operational	Langerwerf Dairy	Butte	Horizontal Plug Flow	1982	Heifer raising facility	750		Cogeneration	60	RCM International, LLC	791
Cancelled	Guepard Energy LLC	San Diego	Unknown		Beef		foodwaste and slaughter byproducts	Electricity; Boiler/Furnace Fuel	1,250		
Cancelled	Bar 20 Dairy 2 - Microgy	Fresno	Complete Mix		Dairy	19,100	Organic waste feedstock (makes up about 40% of digester feed)	Pipeline Gas		Microgy (Environmental Power Corp.)	
Cancelled	Bidart Dairy II	Kern	Horizontal Plug Flow		Dairy	7,200		Electricity	1,000		

New York

Status	Farm/Project Name	County	Digester Type	Year Operational	Farm Type	Population Feeding Digester	Co-Digestion	Biogas End Use(s)	Installed Capacity (kW)	System Designer	Methane Emission Reductions (metric tons CO2E/yr)
Operational	Fessenden Family Dairy	Cayuga	Covered Lagoon	2008	Dairy	800		Electricity	500	Environmental Fabrics, Inc.	3,379
Operational	Roach Dairy Farm	Cayuga	Complete Mix	2010	Dairy	1,350		Electricity	300	RCM International, LLC	1,650
Operational	Ridgecrest Dairy	Cayuga	Covered Lagoon	2008	Dairy	1,650		Flared Full Time		Developed by Environmental Credit Corp.	6,969
Operational	Patterson Farms	Cayuga	Complete Mix	2005	Dairy	1,760	Food processing waste (cheese whey)	Cogeneration	250	RCM International, LLC	1,849
Operational	Aurora Ridge Dairy	Cayuga	Mixed Plug Flow	2009	Dairy	1,800		Electricity	500	GHD, Inc.	2,477
Operational	Twin Birch Dairy	Cayuga	Horizontal Plug Flow	2003	Dairy	1,900		Electricity, Boiler/Furnace Fuel	120	Anaerobics, Inc.	2,034
Operational	Sunnyside Farms	Cayuga	Mixed Plug Flow	2009	Dairy	2,700		Electricity	500	GHD, Inc.	11,403
Operational	Ridgeline Farm	Chautauque	Complete Mix	2001	Dairy	525	Food processing waste (food waste from grapes, milk/ice cream and salad dressing production)	Cogeneration	130	RCM International, LLC	722
Operational	New Hope View Farm	Cortland	Horizontal Plug Flow	2001	Dairy	850		Cogeneration, Boiler/Furnace Fuel	70	RCM International, LLC	3,590
Operational	Zuber Farms	Genesee	Complete Mix	2009	Dairy	1,800	Food wastes (Milk processing waste sludge, powdered milk, processing waste, wasted milk, tomatoe paste)	Cogeneration	400	RCM International, LLC	2,311
Operational	Lamb Farms	Genesee	Mixed Plug Flow	2010	Dairy	2,000		Electricity	450	GHD, Inc.	8,447
Operational	Sheldan Farms	Jefferson	Complete Mix	2007	Dairy	555		Cogeneration	125	Siemens, Stearns & Wheeler, Stanley A. Weeks, LLC; Penn Jersey Products	764
Operational	Noblehurst Farms	Livingston	Horizontal Plug Flow	2003	Dairy	1,300		Cogeneration	130	Cow Power	1,623
Operational	Covne Farm	Livingston	Covered Lagoon	2008	Dairy	1,400		Flared Full Time		Developed by Environmental Credit Corp.	5,913
Operational	SUNY at Morrisville	Madison	Horizontal Plug Flow	2007	Dairy	505	food waste/organic waste	Cogeneration	50	David Palmer at Cow Power, Inc.; Tiry Engineering	612
Operational	Will-O-Crest Farm	Ontario	Covered Lagoon	2008	Dairy	1,050		Flared Full Time		Developed by Environmental Credit Corp.	4,435
Operational	AA Dairy	Tioga	Horizontal Plug Flow	1998	Dairy	600		Cogeneration	130	RCM International, LLC	826
Operational	EL-VI Farms	Wayne	Horizontal Plug Flow	2004	Dairy	1,500		Boiler/Furnace Fuel		Ted Peck; Stanley A. Weeks, LLC	1,483

MASSACHUSETTS

Status	Farm/Project Name	County	Digester Type	Year Operational	Farm Type	Population Feeding Digester	Co-Digestion	Biogas Generation Estimate (ft ³ /day)	Biogas End Use(s)	Installed Capacity (kW)	System Designer
Operational	Jordan Farms / AGreen Energy, LLC	Worcester	Complete Mix	2011	Dairy	375			Electricity		Quasar Bioenergy; Developed by AGreen Energy, LLC
Construction	Pine Island Farm	Berkshire	Mixed Plug Flow		Dairy	650		59,000	Cogeneration	125	GHD, Inc.

Appendix D:

IRB Exemption Notice



OFFICE OF THE VICE PROVOST

Social, Behavioral, and Educational Research
Institutional Review Board
FWA00002063

Re: IRB Study # 1102046
Title: Biogas Field Project
PI: Cameron Peterson
Department: Urban and Environmental Policy and Planning
Co-Investigator(s): Lydia Rainville, Julia Bramley, Cheng-Hao Shih, Axum Teferra, Yuan Wang
Study Coordinator: Lum Fobi
IRB Review Date: 3/1/2011

March 2, 2011

Dear Cameron,

This is the official notification that your project, *Biogas Field Project*, protocol # 1102046 does not meet the definition of human subject research under the Code of Federal Regulations Title 45 Part 46.102(f); therefore is not subject to review by the Institutional Review Board.

Please be sure to file this notification.

Sincerely,

A handwritten signature in black ink, appearing to read "Yvonne Wakeford".

Yvonne Wakeford, Ph.D.
IRB Administrator

Appendix E:

Anaerobic Digester Technologies

A. Covered Lagoon Digester

Covered lagoons are used to produce biogas from liquid manure with less than 3% solids. Due to the low concentration of organic matter, the biochemical process in covered lagoons is slow. They take more time than other digesters to complete the digestion. In other words, the hydraulic retention time (HRT) of liquid manure needs to be long enough (40-60 days). Therefore, large volumes are usually required for covered lagoon, preferably with depths greater than 12 feet (USEPA, 2004). Covered lagoons are usually constructed by excavating and building an embankment around the top edge. They are usually covered with synthetic fabric. Covered lagoon digesters are usually not heated, so they rely on ambient temperature to maintain reactive. It is therefore more feasible for covered lagoon digesters to produce biogas in warm climates. They may be used in cold climates for seasonal biogas recovery and odor control (gas flaring), which is not as economic as in warm climates. The Natural Resources Conservation Service recommends a 40th parallel line, above which collecting biogas for energy production is not feasible (Natural Resources Conservation Service, 2009)

B. Complete-mix Digester

Complete-mix digesters are mechanically mixed engineering tanks with constant volume and controlled temperature. It is designed to process slurry manure with a solid concentration from 3% to 10% (USEPA, 2004). The digester contents should be continuously or intermittently mixed to increase contact between bacteria and substrates. A gas collection and utilization system is connected and a supplemental effluent storage is usually required. This system is considered to be the most robust in terms of the variety of manures that can be processed (Ogejo et al. 2009). Sometimes the process takes place in more than one tank. For instance, acid formers can break down manure in one tank, and then methane formers convert organic acids to biogas in a second tank. Since complete-mix digesters can be heated, they are feasible in all kinds of climate conditions. Moreover, since the solid contents are higher and the reaction condition can be optimized, they have shorter HRT (15+days) and require less land than covered lagoons.

C. Plug-flow Digester

Plug-flow digesters are typically covered long reactors where the manure enters at one end of the reactor and exits at the opposite end. They are engineered, heated tanks

that work best for scraped dairy manure with 11% to 13% total solids. Swine manure is not suitable for plug-flow digesters due to its lack of fiber. In general, a horizontal plug-flow digester's length to width ratio is between 3.5:1 and 5:1 (Ogejo et al. 2009). The shape of the floor and walls shall be designed to facilitate the movement of all material through the digester to minimize short-circuiting flow. Different from a complete mixed digester, very little mixing occurs in a plug-flow digester. Similar to complete mix digesters, plug-flow digesters can be operated at mesophilic environment to promote biochemical reaction. Therefore, the HRT of plug-flow digesters is similar to complete-mix digesters.

D. Fixed-film Digester

The fixed-film digester is a more recent technology. It is an engineered column tank packed with growth media, such as wood chips or small plastic rings, on which the microorganisms grow. Manure liquids pass through the media and the organic matters are absorbed or attached by growth media to feed the microorganisms. These digesters are also called attached growth digesters or anaerobic filters. The growth media in a fixed-film digester dramatically increases the contact surface of bacteria and organic matters. Therefore, the retention time of fixed film digesters can be as low as 2-3 days. This characteristic makes it possible to handle manure with relatively small digesters and less land. Usually, effluent is recycled to combine with inflow in order to maintain a constant upward flow movement. One drawback with fixed film digesters is that manure solids can plug the growth media. So, a solid separator is always needed to remove potential clogging solids from the manure before feeding the digester. Some potential biogas is lost due to removing manure solids.

Appendix F:

German Bank Credit Form

10. Annex

Appendix 1: Questionnaire for biogas plant credits from Umweltbank AG, Germany

Example for a Credit Request Form

(based on the request form of the Umweltbank AG, Germany)

1. Applicant

Full name	
Street, postal code, city	
Telephone	Fax
Cell phone	eMail - Address

Profession ☐ Farmer ☐ Employee ☐ Self-employee ☐ Other: _____

The operation and technical controlling of the plant is supervised by the following person:

Name	Relation to plant operator (e. g. son, long-time employee etc.)	Expertise in the field of biogas (e. g. by training, internship etc.)

Please name your motivation for constructing of a biogas plant:
Which changes in your business do you expect?

--

2. Planned biogas plant

Type of installation:

Plant for dedicated energy crops in conformity of EEG: ☐ yes ☐ no

Utilisation of heat: ☐ no ☐ yes

consumer of heat	kWh/a
------------------	-------

Technical details:

☐ Purchase of a turn-key facility provided by the manufacturer: _____

☐ Purchase of a facility composed of equipment from different suppliers. Name of planner of the overall concept:

Construction management is done by: ☐ applicant ☐ planner ☐ _____

Fermenters and storage facilities:

	number	manufacturer	design (e.g. concrete, steel etc.)	capacity per unit [m ³]	already existing
slurry storage					<input type="radio"/>
silo for feedstock					<input type="radio"/>
main fermenter					<input type="radio"/>
secondary fermenter					<input type="radio"/>
digestate storage					<input type="radio"/>

Stirring technology:

number of stirrers	type of stirrers	manufacturer

Combined heat and power plants:

number	manufacturer	kW per unit	guaranteed efficiency	design
				<input type="radio"/> gas engine <input type="radio"/> pilot injection engine
				<input type="radio"/> gas engine <input type="radio"/> pilot injection engine

Micro-biology:

Biological control
and operation

☐ by plant operator

☐ with support of manufacturer

☐ laboratory contract with _____

Location:

exact address (street, postal code, city) as well as plot number

land owner (Name, Address)

Entries in the land register of the plant location (e.g. land charge, right of way, ect.)

Existing buildings: ☐ No ☐ yes: _____

Access to public streets: ☐ No ☐ yes

Available agricultural land and number of animals of the applicant:

	total area (ha)	percentage of own property	percentage of leased property
arable land			
grassland			

	species	number	type of animal breeding
animals			

Feedstock:

type	supplier	available amount/year (t)	price/t in Euro	cost per year

3. Cost and financing plan

Cost for

planning	€
CHP plant	€
fermenter	€
stirring technology	€
electronic components	€
liquidity reserve	€
other	€
=sum of costs	€

Financed by

equity capital	€
incentives, support	€
own resources	€
other loans	€
loans by Umwelt Bank	€
=sum of financing	€

Explanation of cost and financing plan:

1) Other costs

other costs caused by	costs in Euro
- interest rate during construction phase	
- charges, additional costs	
- costs of first substrate charge	
-	
-	
-	
-	
-	

2) Origin of equity capital

--

3) Incentives

incentive donors	submission date	date of approval

4) Own labour contribution

type of labour	value in Euro
-	
-	
-	

5) Other loans

loan provider	interest rate	planned payback date

Construction timetable:

starting date of construction	finalisation date of construction

4. Required documentation

For the credit application the Umweltbank requires the following documents (copies are sufficient). Personally signed exemplars are just required for "confidential personal information". Required forms can be downloaded at www.umweltbank.de under the heading of "Formulare". Please provide additional information by informal attachments.

Type of documents:

Personal documentation in case of natural person / companies constituted under civil law is:

	attached	submission date
Confidential personal information according to the forms (each shareholder)	<input type="radio"/>	_____
Last three income tax returns (each shareholder)	<input type="radio"/>	_____
Last three payslips (each shareholder) or last three annual balance sheets	<input type="radio"/>	_____
Tabular CV (in case of civil law association: only executive director)	<input type="radio"/>	_____
Company contract	<input type="radio"/>	_____

Personal documentation in case of legal person (private limited partnership, limited company, corporation, ect.)

Last three balance sheets as well as recent business analysis	<input type="radio"/>	_____
Tabular CV of the executive director	<input type="radio"/>	_____
Confidential personal information of the executive director	<input type="radio"/>	_____
Abstract of the commercial register	<input type="radio"/>	_____

Project documentation

Land register map (including plot identification and subscription of the plant)	<input type="radio"/>	_____
Recent certificate of title of plant location	<input type="radio"/>	_____
Leasing contract (in case the applicant is not the land owner)	<input type="radio"/>	_____
Insurance offer (machinery breakage, business interruption, public liability)	<input type="radio"/>	_____
Details of the cost – and financing plan	<input type="radio"/>	_____
Offers for all relevant parts of the plant	<input type="radio"/>	_____
Contract of heat delivery and heat quantity (in case of heat utilization)	<input type="radio"/>	_____
Economic efficiency calculation	<input type="radio"/>	_____
Commitment of grid access by electricity distributor	<input type="radio"/>	_____
Building permission, respectively BImSchG – permission	<input type="radio"/>	_____
Substrate delivery – and contracts for sale of digestate	<input type="radio"/>	_____

Appendix G:

Nonfarm Stakeholder Interviews

Agencies and Organizations Interviewed

- ◆ AgPower Development, LLC
- ◆ AgRefresh
- ◆ Agricultural Energy Consultants, LLC
- ◆ California Environmental Protection Agency
- ◆ State Water Resources Control Board
- ◆ California Air Resources Board
- ◆ Central Vermont Public Services Cow Power Program
- ◆ GHD Inc.
- ◆ Massachusetts Department of Agricultural Resources
- ◆ Massachusetts Department of Environmental Protection
- ◆ NativEnergy
- ◆ New York Department of Environmental Conservation
- ◆ New York State Energy Research and Development Authority Anaerobic Digester Gas-to-Electricity Program
- ◆ USDA Rural Development, Southern New England Office
- ◆ Vermont Department of Environmental Conservation
- ◆ Western United Resource Development
- ◆ Yankee Farm Credit

Appendix H:

NPDES Form 1 and 2B

EPA NPDES Form 1 (EPA.gov)

SECTION B – FORM 1 LINE BY LINE INSTRUCTIONS

This form must be completed by all applicants.

Completing This Form

Please type or print in the unshaded areas only. Some items have small graduation marks in the fill-in spaces. These marks indicate the number of characters that may be entered into our data system. The marks are spaced at 1/6" intervals which accommodate elite type (12 characters per inch). If you use another type you may ignore the marks. If you print, place each character between the marks. Abbreviate if necessary to stay within the number of characters allowed for each item. Use one space for breaks between words, but not for punctuation marks unless they are needed to clarify your response.

Item I

Space is provided at the upper right hand corner of Form 1 for insertion of your EPA Identification Number. If you have an existing facility, enter your Identification Number. If you don't know your EPA Identification Number, please contact your EPA Regional office (Table 1), which will provide you with your number. If your facility is new (not yet constructed), leave this item blank.

Item II

Answer each question to determine which supplementary forms you need to fill out. Be sure to check the glossary in Section D of these instructions for the legal definitions of the **bold faced words**. Check Section C of these instructions to determine whether your activity is excluded from permit requirements.

If you answer "no" to every question, then you do not need a permit, and you do not need to complete and return any of these forms.

If you answer "yes" to any question, then you must complete and file the supplementary form by the deadline listed in Table 2 along with this form. (The applicable form number follows each question and is enclosed in parentheses.) You need not submit a supplementary form if you already have a permit under the appropriate Federal program, unless your permit is due to expire and you wish to renew your permit.

Questions (I) and (J) of Item II refer to major new or modified sources subject to Prevention of Significant Deterioration (PSD) requirements under the Clean Air Act. For the purpose of the PSD program, major sources are defined as: (A) Sources listed in Table 3 which have the potential to emit 100 tons or more per year emissions; and (B) All other sources with the potential to emit 250 tons or more per year. See Section C of these instructions for discussion of exclusions of certain modified sources.

Table 3. 28 Industrial Categories Listed In Section 169(1) of the Clean Air Act of 1977

Fossil fuel-fired steam generators of more than 250 million BTU per hour heat input;
Coal cleaning plants (with thermal dryers);
Kraft pulp mills;
Portland cement plants;
Primary zinc smelters;
Iron and steel mill plants;
Primary aluminum ore reduction plants;
Primary copper smelters;
Municipal incinerators capable of charging more than 250 tons of refuse per day;
Hydrofluoric acid plants;
Nitric acid plants;
Sulfuric acid plants;
Petroleum refineries;
Lime plants;
Phosphate rock processing plants;
Coke oven batteries;
Sulfur recovery plants;
Carbon black plants (furnace process);
Primary lead smelters;
Fuel conversion plants;
Sintering plants;
Secondary metal production plants;
Chemical process plants;
Fossil fuel boilers (or combination thereof) totaling more than 250 million BTU per hour heat input;

Table 3 (continued)

Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
Taconite ore processing plants;
Glass fiber processing plants; and
Charcoal production plants.

Item III

Enter the facility's official or legal name. Do not use a colloquial name.

Item IV

Give the name, title, and work telephone number of a person who is thoroughly familiar with the operation of the facility and with the facts reported in this application and who can be contacted by reviewing offices if necessary.

Item V

Give the complete mailing address of the office where correspondence should be sent. This often is not the address used to designate the location of the facility or activity.

Item VI

Give the address or location of the facility identified in Item III of this form. If the facility lacks a street name or route number, give the most accurate alternative geographic information (e.g., section number or quarter section number from county records or at intersection of Rts. 425 and 22).

Item VII

List, in descending order of significance, the four 4-digit standard industrial classification (SIC) codes which best describe your facility in terms of the principal products or services you produce or provide. Also, specify each classification in words. These classifications may differ from the SIC codes describing the operation generating the discharge, air emissions, or hazardous wastes.

SIC code numbers are descriptions which may be found in the "Standard Industrial Classification Manual" prepared by the Executive Office of the President, Office of Management and Budget, which is available from the Government Printing Office, Washington, D.C. Use the current edition of the manual. If you have any questions concerning the appropriate SIC code for your facility, contact your EPA Regional office (see Table 1).

Item VIII-A

Give the name, as it is legally referred to, of the person, firm, public organization, or any other entity which operates the facility described in this application. This may or may not be the same name as the facility. The operator of the facility is the legal entity which controls the facility's operation rather than the plant or site manager. Do not use a colloquial name.

Item VIII-B

Indicate whether the entity which operates the facility also owns it by marking the appropriate box.

Item VIII-C

Enter the appropriate letter to indicate the legal status of the operator of the facility. Indicate "public" for a facility solely owned by local government(s) such as a city, town, county, parish, etc.

Items VIII-D-H

Enter the telephone number and address of the operator identified in Item VIII-A.

Item IX

Indicate whether the facility is located on Indian Lands.

Item X

Give the number of each presently effective permit issued to the facility for each program or, if you have previously filed an application but have not yet received a permit, give the number of the application, if any. Fill in the unshaded area only. If you have more than one currently effective permit for your facility under a particular permit program, you may list additional permit numbers on a separate sheet of paper. List any relevant environmental Federal (e.g., permits

SECTION B – FORM 1 LINE BY LINE INSTRUCTIONS

under the Ocean Dumping Act, Section 404 of the Clean Water Act or the Surface Mining Control and Reclamation Act), State (e.g., State permits for new air emission sources in nonattainment areas under Part D of the Clean Air Act or State permits under Section 404 of the Clean Water Act), or local permits or applications under "other."

Item XI

Provide a topographic map or maps of the area extending at least to one mile beyond the property boundaries of the facility which clearly show the following:

The legal boundaries of the facility;

The location and serial number of each of your existing and proposed intake and discharge structures;

All hazardous waste management facilities;

Each well where you inject fluids underground; and

All springs and surface water bodies in the area, plus all drinking water wells within 1/4 mile of the facility which are identified in the public record or otherwise known to you.

If an intake or discharge structure, hazardous waste disposal site, or injection well associated with the facility is located more than one mile from the plant, include it on the map, if possible. If not, attach additional sheets describing the location of the structure, disposal site, or well, and identify the U.S. Geological Survey (or other) map corresponding to the location.

On each map, include the map scale, a meridian arrow showing north, and latitude and longitude at the nearest whole second. On all maps of rivers, show the direction of the current, and in tidal waters, show the directions of the ebb and flow tides. Use a 7-1/2 minute series map published by the U.S. Geological Survey, which may be obtained through the U.S. Geological Survey Offices listed below. If a 7-1/2 minute series map has not been published for your facility site, then you may use a 15 minute series map from the U.S. Geological Survey. If neither a 7-1/2 nor 15 minute series map has been published for your facility site, use a plat map or other appropriate map, including all the requested information; in this case, briefly describe land uses in the map area (e.g., residential, commercial).

You may trace your map from a geological survey chart, or other map meeting the above specifications. If you do, your map should bear a note showing the number or title of the map or chart it was traced from. Include the names of nearby towns, water bodies, and other prominent points. An example of an acceptable location map is shown in Figure 1-1 of these instructions. (NOTE: Figure 1-1 is provided for purposes of illustration only, and does not represent any actual facility.)

U.S.G.S. OFFICES	AREA SERVED
Eastern Mapping Center National Cartographic Information Center U.S.G.S. 536 National Center Reston, VA 22092 Phone No. (703) 860-6336	Ala., Conn., Del., D.C., Fla., Ga., Ind., Ky., Maine, Md., Mass., N.H., N.J., N.Y., N.C., S.C., Ohio, Pa., Puerto Rico, R.I., Tenn., Vt., Va., W. Va., and Virgin Islands
Mid Continent Mapping Center National Cartographic Information Center U.S.G.S. 1400 Independence Road Rolla, MO 65401 Phone No. (314) 341-0851	Ark., Ill., Iowa, Kans., La., Mich., Minn., Miss., Mo., N. Dak., Nebr., Okla., S. Dak., and Wis.
Rocky Mountain Mapping Center National Cartographic Information Center U.S.G.S. Stop 504, Box 25046 Federal Center Denver, CO 80225 Phone No. (303) 234-2326	Alaska, Colo., Mont., N. Mex., Tex., Utah, and Wyo.
Western Mapping Center National Cartographic Information Center U.S.G.S. 345 Middlefield Road Menlo Park, CA 94025 Phone No. (415) 323-8111	Ariz., Calif., Hawaii, Idaho, Nev., Oreg., Wash., American Samoa, Guam, and Trust Territories

Item XII

Briefly describe the nature of your business (e.g., products produced or services provided).

Item XIII

Federal statutes provide for severe penalties for submitting false information on this application form.

18 U.S.C. Section 1001 provides that "Whoever, in any matter within the jurisdiction of any department or agency of the United States knowingly and willfully falsifies, conceals or covers up by any trick, scheme, or device a material fact, or makes or uses any false writing or document knowing some to contain any false, fictitious or fraudulent statement or entry, shall be fined not more than \$10,000 or imprisoned not more than five years, or both."

Section 309(c)(2) of the Clean Water Act and Section 113(c)(2) of the Clean Air Act each provide that "Any person who knowingly makes any false statement, representation, or certification in any application, . . . shall upon conviction, be punished by a fine of no more than \$10,000 or by imprisonment for not more than six months, or both."

In addition, Section 3008(d)(3) of the Resource Conservation and Recovery Act provides for a fine up to \$25,000 per day or imprisonment up to one year, or both, for a first conviction for making a false statement in any application under the Act, and for double these penalties upon subsequent convictions.

FEDERAL REGULATIONS REQUIRE THIS APPLICATION TO BE SIGNED AS FOLLOWS:

A. For a corporation, by a principal executive officer of at least the level of vice president. However, if the only activity in Item II which is marked "yes" is Question G, the officer may authorize a person having responsibility for the overall operations of the well or well field to sign the certification. In that case, the authorization must be written and submitted to the permitting authority.

B. For partnership or sole proprietorship, by a general partner or the proprietor, respectively; or

C. For a municipality, State, Federal, or other public facility, by either a principal executive officer or ranking elected official.

Please print or type in the unshaded areas only.

Form Approved. OMB No. 2040-0086.

FORM 1 GENERAL		U.S. ENVIRONMENTAL PROTECTION AGENCY GENERAL INFORMATION Consolidated Permits Program (Read the "General Instructions" before starting.)		I. EPA I.D. NUMBER	
LABEL ITEMS		PLEASE PLACE LABEL IN THIS SPACE		GENERAL INSTRUCTIONS	
				If a preprinted label has been provided, affix it in the designated space. Review the information carefully; if any of it is incorrect, cross through it and enter the correct data in the appropriate fill-in area below. Also, if any of the preprinted data is absent (the area to the left of the label space lists the information that should appear), please provide it in the proper fill-in area(s) below. If the label is complete and correct, you need not complete Items I, III, V, and VI (except VI-B which must be completed regardless). Complete all items if no label has been provided. Refer to the instructions for detailed item descriptions and for the legal authorizations under which this data is collected.	
II. POLLUTANT CHARACTERISTICS					
INSTRUCTIONS: Complete A through J to determine whether you need to submit any permit application forms to the EPA. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the box in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements; see Section C of the instructions. See also, Section D of the instructions for definitions of bold-faced terms .					
SPECIFIC QUESTIONS		Mark "X"		SPECIFIC QUESTIONS	
		YES	NO	FORM ATTACHED	
A. Is this facility a publicly owned treatment works which results in a discharge to waters of the U.S. ? (FORM 2A)					
		16	17	18	
C. Is this a facility which currently results in discharges to waters of the U.S. other than those described in A or B above? (FORM 2C)					
		22	23	24	
E. Does or will this facility treat, store, or dispose of hazardous wastes ? (FORM 3)					
		28	29	30	
G. Do you or will you inject at this facility any produced water or other fluids which are brought to the surface in connection with conventional oil or natural gas production, inject fluids used for enhanced recovery of oil or natural gas, or inject fluids for storage of liquid hydrocarbons? (FORM 4)					
		34	35	36	
I. Is this facility a proposed stationary source which is one of the 28 industrial categories listed in the instructions and which will potentially emit 100 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)					
		40	41	42	
B. Does or will this facility (either existing or proposed) include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters of the U.S. ? (FORM 2B)					
		19	20	21	
D. Is this a proposed facility (other than those described in A or B above) which will result in a discharge to waters of the U.S. ? (FORM 2D)					
		25	26	27	
F. Do you or will you inject at this facility industrial or municipal effluent below the lowermost stratum containing, within one quarter mile of the well bore, underground sources of drinking water? (FORM 4)					
		31	32	33	
H. Do you or will you inject at this facility fluids for special processes such as mining of sulfur by the Frasch process, solution mining of minerals, in situ combustion of fossil fuel, or recovery of geothermal energy? (FORM 4)					
		37	38	39	
J. Is this facility a proposed stationary source which is NOT one of the 28 industrial categories listed in the instructions and which will potentially emit 250 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area ? (FORM 5)					
		43	44	45	
III. NAME OF FACILITY					
C. SKIP					
1					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					
IV. FACILITY CONTACT					
A. NAME & TITLE (last, first, & title)					
B. PHONE (area code & no.)					
C. 1					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					
V. FACILITY MAILING ADDRESS					
A. STREET OR P.O. BOX					
C. 3					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					
B. CITY OR TOWN					
C. STATE					
D. ZIP CODE					
C. 4					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					
VI. FACILITY LOCATION					
A. STREET, ROUTE NO. OR OTHER SPECIFIC IDENTIFIER					
C. 5					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					
B. COUNTY NAME					
C. 6					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					
C. CITY OR TOWN					
D. STATE					
E. ZIP CODE					
F. COUNTY CODE (if known)					
C. 6					
15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99					

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CONTINUE ON REVERSE

CONTINUED FROM THE FRONT

VII. SIC CODES (4-digit, in order of priority)									
A. FIRST					B. SECOND				
C	7			(specify)	C	7			(specify)
15	16	-	18		15	16	-	18	
C. THIRD					D. FOURTH				
C	7			(specify)	C	7			(specify)
15	16	-	18		15	16	-	18	
VIII. OPERATOR INFORMATION									
A. NAME								B. Is the name listed in item VIII-A also the owner?	
C	8								<input type="checkbox"/> YES <input type="checkbox"/> NO
15	16								55 65
C. STATUS OF OPERATOR (Enter the appropriate letter into the answer box: if "Other," specify.)								D. PHONE (area code & no.)	
F = FEDERAL S = STATE P = PRIVATE				M = PUBLIC (other than federal or state) O = OTHER (specify)				A	
								15 16 - 18 19 - 21 22 - 26	
E. STREET OR P.O. BOX									
26 55									
F. CITY OR TOWN					G. STATE	H. ZIP CODE	IX. INDIAN LAND		
C	B							Is the facility located on Indian lands?	
15	16				40 41	42 47	-	51	<input type="checkbox"/> YES <input type="checkbox"/> NO
X. EXISTING ENVIRONMENTAL PERMITS									
A. NPDES (Discharges to Surface Water)					D. PSD (Air Emissions from Proposed Sources)				
C	T	I			C	T	I		
9	N				9	P			
15	16	17	18		30	15	16	17	18
B. UIC (Underground Injection of Fluids)					E. OTHER (specify)				
C	T	I			C	T	I		
9	U				9				(specify)
15	16	17	18		30	15	16	17	18
C. RCRA (Hazardous Wastes)					E. OTHER (specify)				
C	T	I			C	T	I		
9	R				9				(specify)
15	16	17	18		30	15	16	17	18
XI. MAP									
<p>Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers, and other surface water bodies in the map area. See instructions for precise requirements.</p>									
XII. NATURE OF BUSINESS (provide a brief description)									
XIII. CERTIFICATION (see instructions)									
<p>I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.</p>									
A. NAME & OFFICIAL TITLE (type or print)					B. SIGNATURE			C. DATE SIGNED	
COMMENTS FOR OFFICIAL USE ONLY									
C									
15	16								55

EPA NPDES Form 2B (EPA.gov)

INSTRUCTIONS

<p>GENERAL</p> <p>This form must be completed by all applicants who check "yes" to Item II-B in Form 1. Not all animal feeding operations or fish farms are required to obtain NPDES permits. Exclusions are based on size and whether or not the facility discharges proposed to discharge. See the description of these exclusions in the CAFO regulations at 40 CFR 122.23.</p> <p>For aquatic animal production facilities, the size cutoffs are based on whether the species are warm water or cold water, on the production weight per year in harvestable pounds, and on the amount of feeding in pounds of food (<i>for cold water species</i>). Also, facilities which discharge less than 30 days per year, or only during periods of excess runoff (<i>for warm water fish</i>) are not required to have a permit.</p> <p>Refer to the Form 1 instructions to determine where to file this form.</p> <p>Item I-A</p> <p>See the note above to be sure that your facility is a "concentrated animal feeding operation" (CAFO).</p> <p>Item I-B</p> <p>Use this space to give owner/operator contact information.</p> <p>Item I-C</p> <p>Check "proposed" if your facility is not now in operation or is expanding to meet the definition of a CAFO in accordance with the CAFO regulations at 40 CFR 122.23.</p> <p>Item I-D</p> <p>Use this space to give a complete legal description of your facility's location including name, address, and latitude/longitude. Also, if a contract grower, the name and address of the integrator.</p> <p>Item II</p> <p>Supply all information in item II if you checked (1) in item I-A.</p> <p>Item II-A</p> <p>Give the maximum number of each type of animal in open confinement or housed under roof (either partially or totally) which are held at your facility for a total of 45 days or more in any 12 month period. Provide the total number of animals confined at the facility.</p> <p>Item II-B</p> <p>Provide the total amount of manure, litter, and wastewater generated annually by the facility. Identify if manure, litter, and wastewater generated by the facility is to be land applied and the number of acres, under the control of the CAFO operator, suitable for land application. If the answer to question 3 is yes, provide the estimated annual quantity of manure, litter, and wastewater that the applicant plans to transfer off-site.</p> <p>Item II-C</p> <p>Check this box if you have submitted a topographic map of the entire operation, including the production area and land under the operational control of the CAFO operator where manure, litter, and/or wastewater are applied with Form 1.</p>	<p>Item II-D</p> <ol style="list-style-type: none"> 1. Provide information on the type of containment and the capacity of the containment structure (s). 2. The number of acres that are drained and collected in the containment structure (s). 3. Identify the type of storage for the manure, litter, and/or wastewater. Give the capacity of this storage in days. <p>Item II-E</p> <p>Provide information concerning the status of submitting a nutrient management plan for the facility to complete the application. In those cases where the nutrient management plan has not been submitted, provide an explanation. If not land applying, describe the alternative uses of the manure, litter, and wastewater (<i>e.g.</i>, composting, pelletizing, energy generation, etc.).</p> <p>Item II-F</p> <p>Check any of the identified conservation practices that are being implemented at the facility to control runoff and protect water quality.</p> <p>Item III</p> <p>Supply all information in Item III if you checked (2) in Item I-A.</p> <p>Item III-A</p> <p>Outfalls should be numbered to correspond with the map submitted in Item XI of Form 1. Values given for flow should be representative of your normal operation. The maximum daily flow is the maximum measured flow occurring over a calendar day. The maximum 30-day flow is the average of measured daily flow over the calendar month of highest flow. The long-term average flow is the average of measure daily flows over a calendar year.</p> <p>Item III-B</p> <p>Give the total number of discrete ponds or raceways in your facility. Under "other," give a descriptive name of any structure which is not a pond or a raceway but which results in discharge to waters of the United States.</p> <p>Item III-C</p> <p>Use names for receiving water and source of water which correspond to the map submitted in Item XI of Form 1.</p> <p>Item III-D</p> <p>The names of fish species should be proper, common, or scientific names as given in special Publication No. 6 of the American Fisheries Society. "A List of Common and Scientific Names of Fishes from the United States and Canada." The values given for total weight produced by your facility per year and the maximum weight present at any one time should be representative of your normal operation.</p> <p>Item III-E</p> <p>The value given for maximum monthly pounds of food should be representative of your normal operation.</p> <p>Item IV</p> <p>The Clean Water Act provides for severe penalties for submitting false information on this application form.</p> <p>Section 309(C)(2) of the Clean Water Act provides that "Any person who knowingly makes any false statement, representation, or certification in any application...shall upon conviction, be punished by a fine of no more than \$10,000 or by imprisonment for not more than six months, or both."</p>
<p>Federal regulations require the certification to be signed as follows:</p> <p>A. For corporation, by a principal executive officer of at least the level of vice president.</p> <p>B. For a partnership or sole proprietorship, by a general partner or the proprietor, respectively; or</p> <p>C. For a municipality, State, federal, or other public facility, by either a principal executive officer or ranking elected official.</p>	<p>Paper Reduction Act Notice</p> <p>The public reporting and recordkeeping burden for this collection of information is estimated to average 9.5 hours per response. The public reporting and recordkeeping burden for development of the nutrient management plan to be submitted with the form is estimated to average 58 hours per response. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.</p>

C. <input type="checkbox"/> TOPOGRAPHIC MAP		
D. TYPE OF CONTAINMENT, STORAGE AND CAPACITY		
1. Type of Containment	Total Capacity (in gallons)	
<input type="checkbox"/> Lagoon		
<input type="checkbox"/> Holding Pond		
<input type="checkbox"/> Evaporation Pond		
<input type="checkbox"/> Other: Specify _____		
2. Report the total number of acres contributing drainage: _____ acres		
3. Type of Storage	Total Number of Days	Total Capacity (gallons/tons)
<input type="checkbox"/> Anaerobic Lagoon		
<input type="checkbox"/> Storage Lagoon		
<input type="checkbox"/> Evaporation Pond		
<input type="checkbox"/> Aboveground Storage Tanks		
<input type="checkbox"/> Belowground Storage Tanks		
<input type="checkbox"/> Roofed Storage Shed		
<input type="checkbox"/> Concrete Pad		
<input type="checkbox"/> Impervious Soil Pad		
<input type="checkbox"/> Other: Specify _____		
E. NUTRIENT MANAGEMENT PLAN		
Note: Effective February 27, 2009, a permit application is not complete until a nutrient management plan is submitted to the Permitting Authority.		
1. Please indicate whether a nutrient management plan has been included with this permit application. <input type="checkbox"/> Yes <input type="checkbox"/> No		
2. If no, please explain:		
3. Is a nutrient management plan being implemented for the facility? <input type="checkbox"/> Yes <input type="checkbox"/> No		
4. The date of the last review or revision of the nutrient management plan. Date: _____		
5. If not land applying, describe alternative use(s) of manure, litter, and/or wastewater:		
F. LAND APPLICATION BEST MANAGEMENT PRACTICES		
Please check any of the following best management practices that are being implemented at the facility to control runoff and protect water quality:		
<input type="checkbox"/> Buffers <input type="checkbox"/> Setbacks <input type="checkbox"/> Conservation tillage <input type="checkbox"/> Constructed wetlands <input type="checkbox"/> Infiltration field <input type="checkbox"/> Grass filter <input type="checkbox"/> Terrace		

A. For each outfall give the maximum daily flow, maximum 30-day flow, and the long-term average flow.				B. Indicate the total number of ponds, raceways, and similar structures in your facility.			
1. Outfall No.	2. Flow (gallons per day)			1. Ponds	2. Raceways	3. Other	
	a. Maximum Daily	b. Maximum 30 Day	c. Long Term Average	C. Provide the name of the receiving water and the source of water used by your facility.			
				1. Receiving Water	2. Water Source		
D. List the species of fish or aquatic animals held and fed at your facility. For each species, give the total weight produced by your facility per year in pounds of harvestable weight, and also give the maximum weight present at any one time.							
1. Cold Water Species				2. Warm Water Species			
a. Species		b. Harvestable Weight (pounds)		a. Species		b. Harvestable Weight (pounds)	
		(1) Total Yearly	(2) Maximum			(1) Total Yearly	(2) Maximum
E. Report the total pounds of food during the calendar month of maximum feeding.				1. Month		2. Pounds of Food	
IV. CERTIFICATION							
I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.							
A. Name and Official Title (print or type)				B. Telephone (_____) _____			
C. Signature				D. Date Signed			

Appendix I:

List of Federal Funding Resources

1. Federal Government Funding

Grants

Rural Energy for America Program (REAP) Grant: Renewable energy facilities can apply to the USDA Rural Development department for a grant of up to 25% of the proposed project's cost. These grants are specifically for agricultural producers and small businesses, and can be used for the purchase and installation of renewable energy facilities. The maximum dollar amounts vary, depending on the purposes, but cannot exceed \$500,000 for renewable energy facilities, and receiving one of these grants is very competitive. USDA now also offers REAP Feasibility Grants, which are intended to fund agricultural producers and rural small businesses to conduct studies and determine cost-effective opportunities for new renewable energy measures. These grants can be up to 25% of the cost of the study, or \$50,000, whichever is less. If this grant is applied for in conjunction with the REAP guarantee loan program, then the application is given priority.

Environmental Quality Incentives Program (EQIP): EQIP offers financial and technical help to eligible livestock producers for the installation and implementation of structural or management practices to improve the environmental quality on agricultural lands. Eligible facilities apply to the state in which they are located in order to receive the funds, and the states have discretion over how the funds are allocated; with some restrictions from the Federal government. EQIP offers contracts ranging from 1 to 10 years to help share the costs of certain conservation practices through incentive payments and cost-share grants. EQIP may cost share up to 75% of the cost of these conservation practices, with certain limited facilities being eligible for up to 90% cost sharing. An AD facility may not exceed, through the aggregate of grants and cost sharing, more than \$450,000 for all contracts entered during the term of the 2008 program.

Conservation Innovation Grants (CIG): CIG is a program run under EQIP, which functions as a tool to stimulate the development and adoption of innovative conservation approaches and techniques. The program funds projects and conservation field trials that can last from one to three years. Grants cannot exceed more than 50% of the total project costs, and the contribution for a single project cannot exceed \$1 million. Projects using approaches that are eligible for EQIP are not eligible for CIG. CIG is intended for technologies that have been studied sufficiently to have a high probability of success, and can eventually be eligible for technology transfer.

Sustainable Agriculture Research and Education (SARE): This program assists farmers to adopt sustainable agricultural practices to improve profits, protect the environment, and enhance quality of life. While these grants are primarily for research and education, they can be applied to developing an AD facility if that development was done in conjunction with scientists and other researchers in an interdisciplinary study, or was part of a marketing or demonstration project that would share results.

Value-Added Producer Grants: Independent producer, farmer, and rancher cooperatives and agricultural producer groups are eligible to apply for this funding to assist with feasibility studies or business plans, or with working capital for marketing value-added agricultural products, or for farm-based renewable energy projects. Eligible participants can receive up to \$100,000 per project if in the planning stage, and working capital grants of up to \$300,000 per project. A cost share of at least 50% is required, and planning and working capital grants cannot be applied for with the same application.

Non-Point Source Water Pollution Control: This program, established as part of the CWA, helps fund state nonpoint source pollution control programs. Because the funds are allocated to the states and not directly to the facilities, the implementation of the program varies state to state, as does the eligibility for the funding, an agricultural AD facility might be eligible for technical assistance, technology transfer, demonstration projects, or other aspects of the AD facility.

Renewable Energy Production Incentive (REPI): This grant is a foil to the Production Tax Credit for facilities not held as corporations, because the PTC can only be taken as a corporate tax credit. Qualifying systems are eligible to receive payments of 1.5 cents per kilowatt hour (adjusted for inflation from 1993 dollars) of electricity produced and sold to an unrelated party. These payments, however, are contingent on annual appropriations. As such, although the program has been authorized for fiscal years 2006 to 2026, no payments have been made since 2009. Additionally, the applicability of this grant to agricultural AD is limited, as most of those facilities will operate as corporations.

High Energy Cost Grant Program: This is a program for facilities in rural communities that have energy costs at least 275% above the national average. If in one of these communities, grants ranging from \$75,000 to \$5 million are available for a variety of activities including electric generation, transmission, and distribution facilities, and renewable energy facilities for on-grid or off-grid electric power generation; including biomass technology.

U.S. Department of Treasury Renewable Energy Grants (Cash Grants): Any facility that is eligible to take the ITC can, instead, elect to receive a one-time cash grant in the amount of the ITC—this includes those facilities eligible to take the ITC in lieu of the PTC. The grant can only be taken for facilities that begin construction before December 31, 2011, and are operational by January 1, 2014. This program has already been extended once beyond its 2010 sunset, but it is unclear whether these extensions will continue. The government issues a check in the amount of 30% of eligible investment costs within 60 days of the grant application date or the facility becoming operational, whichever is later. So, the Cash Grant functions as cash in hand, as opposed to a reduction in taxes in the future.

Loans

Business and Industry Guaranteed Loan Program: In order to incentivize lenders to lend money to businesses in rural communities that engage in certain socially or economically desirable enterprises, such as agricultural AD, the federal government is willing to guarantee up to 80% of the loan made by the lender to an eligible borrower. The loan itself can be used for a number of items, including purchasing machinery and equipment, buildings, real estate, or working capital. An eligible borrower is a business in a rural community that will use the money to either: (1) provide employment; (2) improve the economic or environmental climate; (3) promote the conservation, development, and use of water for aquaculture; or (4) reduce reliance on nonrenewable energy sources. This program is only intended for lenders supplying prime loans, and not marginal or substandard loans (AgSTAR, YEAR). Essentially, this program guarantees that, regardless of what happens with the business, the bank will recoup at least 80% of the funds it loaned out, thus reducing the risk of the investment substantially.

Rural Energy for America Program (REAP) Guarantee Loan Program: This loan guarantee encourages the commercial financing of renewable energy facilities for, among others, livestock producers and rural small businesses, including agricultural AD. The USDA Rural Development department guarantees up to \$25 million in loans or 75% of the proposed project's cost, whichever is lower. This works in conjunction with the REAP Grant Program, and together the two may not exceed 75% of the project cost.

Conservation Loan Program (CL): Farm owners and farm related businesses can receive loans, or loan guarantees to aid the implementation of conservation practices approved by the Natural Resources Conservation Service. This includes manure management

systems and AD. The loans can be up to a value of \$300,000, and loan guarantees up to a value of \$1,112,000 if the lender works with the FSA.

Tax Credits

Federal Renewable Electricity Production Tax Credit (26 USC § 45): Traditionally, the only tax credit available to agricultural AD facilities was the Production Tax Credit (PTC), which remains the cornerstone of federal policies supporting renewable energy. The PTC was originally enacted as part of the EPAct of 1992 and has been periodically extended, with each extension lasting only for a limited period. The value of this credit is based on amount of energy produced, and requires that energy must be sold to an unrelated party. The credit is available for electricity generated from “qualified energy resources” and sold by the taxpayer to an unrelated person during the taxable year. One qualified energy resource is open-loop biomass, which the Internal Revenue Code defines to include any agricultural livestock manure and litter, including wood shavings, straw, rice hulls, and other bedding material for the disposition of manure. Additionally, a qualified facility is one that was originally placed in service between October 22, 2004 and December 31, 2013, and has a nameplate capacity of not less than 150 KW.

The amount of the credit available per kilowatt hour changes from year to year, but is currently 1.1 cents per kilowatt hour. The credit can usually be claimed every year for the ten-year period beginning on the date in which the facility was placed in service. The uncertainty of whether or not the PTC will continue to be extended, however, is one of the primary drawbacks of this tax credit. Because the development process of a facility can take years, there is often hesitation on the part of investors who fear that the PTC will no longer be available by the time the facility is placed in operation. Another drawback is that the PTC is tied to the amount of energy produced, and not the cost of the facility, so if an expensive facility is not as efficient as anticipated, the PTC will not offset as much of the development costs as necessary. Moreover, the PTC is not available for many agricultural AD facilities because it requires that the electricity produced be sold to an unrelated third party, and often agricultural AD facilities produce electricity for their own use only.

Business Energy Investment Tax Credit (ITC) (26 USC § 48): Beginning in 2009 with the American Recovery and Reinvestment Act, the ITC was extended to include open-loop biomass projects that would have qualified for the PTC. Qualifying facilities now have the option of opting out of the PTC, and electing to take a one-time corporate tax credit in the amount of 30% of the eligible cost of the facility. This typically includes costs

that are integral to the generating facility, excepting ancillary costs like transmission lines and site improvements (See IRS Notice 2009-52). The deduction, however, is tied entirely to costs of the facility, not to electricity produced, and there is no requirement that the electricity be sold. Thus, this credit would be available for many agricultural AD facilities that could not claim the PTC due to these restrictions.

The entire 30% credit can be taken in the first year that the facility is placed in operation, but it vests only 20% a year over a period of five years. This means that the owner who claims the tax credit—usually an investor—must maintain his ownership interest in the facility for at least five years, or that owner will have to pay a portion of the tax credit claimed back to the government. After five years, the entire credit will have vested, and the owner who claimed the credit can sell his interest in the facility without having to repay any of the credit. Currently, this credit is available for facilities placed in service by December 31, 2013, and it is unclear whether the expanded ITC credit will be extended beyond this date.

Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation (2008-2012) (26 USC §§ 168, 48): Owners of facilities are also able to recoup the cost of the facility through depreciation deductions. Instead of the normal depreciation period for personal property, which can range as high as fifty years, AD facilities are eligible to be completely depreciated over seven years. Thus, the owners of the facility can deduct the facility's entire eligible cost in larger amounts over a shorter time period. Depending on the details of the facility, certain costs may also be deducted at a rate of 50% or 100% in the first year of operation (DSIRE, YEAR).

2. Vermont Government Funding

Grants

Clean Energy Development Fund (CEDF): Pre-Project Financial Assistance Grants of up to \$100,000 are available to assist with costs incurred prior to operation. The facility must be completed within one year of the award, and these grants also require that a 20% or 50% cash match be provided, depending on the award's size. Large-Scale System Grants are awarded for facilities expected to produce more than 15 kW of power with all projects connecting directly to the grid. The maximum grant award in this category is \$250,000, and requires a 50% cash match of which no more than 25% can be from in-kind resources. These projects must be completed within two years of the award.

Central Vermont Public Service Corporation (CVPS) Biomass Grants: CVPS, Vermont's largest electric utility, receives credits from several nuclear energy insurance companies pursuant to a sales contract. A large portion of the credit received is used directly to fund grants and other incentives to encourage the development of AD facilities that use agricultural products. In addition to providing a project coordinator to help sites develop an AD facility, the grants support project development, project operations, and interconnection to the grid. The amount and types of awards are made on a case-by-case basis.

Vermont Agency of Agriculture, Food, and Markets (VAAFM): The VAAFM offers funding for improvements and innovation in manure management systems. The agency is particularly concerned with nutrient management, manure handling, and supports manure management projects that have a renewable energy component to them. For details on these grants you must contact the agency.

Production Incentives

Vermont's SPEED Program: In June 2005, the Vermont Legislature enacted the Sustainably Priced Energy Enterprise Development (SPEED) Program within 30 V.S.A. § 8005 and § 8001. The SPEED Program is implemented through the Vermont Public Service Board and applies to electric distribution, transmission, and eligible in-state generation facilities for renewable fuel projects. Primarily administered by Vermont's Public Service Board (PSB), SPEED aims to produce all new load growth in the state from January 1, 2005 to July 1, 2012 via renewable resources that are not net-metered.

The Vermont Standard Offer Program: The Vermont Energy Act of 2009 expanded the SPEED Program to include feed-in-tariffs, and effectively established the first statewide FIT program in the United States. The technologies included in the program are Landfill Methane, Farm Methane (agricultural biogas), Wind, Solar Photovoltaic, Hydropower, and Biomass. No project can exceed 2.2 MW, and no one technology can comprise more than 25% of the total capacity cap of 50 MW. SPEED projects must apply for and be granted a "Certificate of Public Good," with projects of 150 kilowatts or less conforming to the standards for a "Certificate of Public Good for Net Metered Systems."

All Vermont retail electricity providers are required to purchase the electricity generated by eligible renewable energy facilities through long-term, typically twenty-year, contracts with fixed standard rates. The intention is to encourage renewable energy investment and development by guaranteeing a reasonable return on the investment.

Labeled a Standard Offer Contract mechanism, the FIT program in Vermont offers a fixed rate for electricity that is required to be less than the anticipated market price. FITs may only provide for rates equal to the rate fixed by the PSB, unless the contract was formed prior to the Vermont Energy Act and has the consent of the PSB. Contracted rates are differentiated among the technology employed, size of the technology capacity (in the case of wind farms), and costs of production. Unlike all other renewable resources under SPEED, methane developed from agricultural resources is not required to transfer the renewable energy credits (RECs) created through the generation to the electric company.

CVPS Biomass Electricity Production Incentive: CVPS offers a production incentive to farms who own systems utilizing agricultural AD. CVPS purchases the electricity and RECs at 95% of the locational marginal price at market, plus an addition 4-cents per kilowatt hour. Eligible systems must be connected to the grid, and net metering is not available under this arrangement. CVPS sells the RECs received under this arrangement as part of CVPS's Cow Power, the utility's green power program.

Loans

Clean Energy Financing Districts (Local Option): Vermont has authorized local governments to create PACE funding districts. Property owners have the option of whether to participate in the program by signing a contract with the municipality. Additional funding for the program is provided by the Clean Energy Development Fund.

Clean Energy Development Fund (CEDF): The CEDF promotes clean electric energy technologies and programs by providing grants and loans to individuals, companies, nonprofits, and municipalities for purchasing land and buildings, purchasing and installing machinery and equipment, and working capital. The loans provided have a fixed interest rate of 2%, with a minimum loan amount of \$50,000 and a maximum loan amount of \$750,000. Loans may only cover up to 90% of projects costs, and must be used for activities and assets directly related to the project.

Taxes

Property Tax Exemption (Local Option): Vermont allows municipalities to exempt the municipal real and personal property taxes for certain renewable energy systems, including facilities used to convert organic matter to methane.

Renewable Energy Systems Sales Tax Exemption: Vermont offers a sales tax exemption on the purchase of renewable energy systems, including AD from agricultural products. The exemption applies generally to projects of up to 250 kilowatts in capacity.

3. California Government Funding

Grants

Dairy Power Production Program (DPPP): Most digesters in California were built after 2004, due to the availability of DPPP funding at that time (DPPP, 2006). The California Energy Commission (CEC) commissioned the DPPP grant. Two types of assistances were made available: buydown grants, which cover up to 50% of the capital costs of the proposed biogas system (not exceeding \$2,000 per installed kilowatt), and incentive payment grants to pay for electricity generated at 5.7 cents per kilowatt-hour.

Section 319 Grant: Section 319 of the 1987 Federal Clean Water Act established a grant program to fund innovative nonpoint source pollution management strategies. The California State Water Resources Control Board (SWRCB) administers the \$5 million grant program to help meet total daily maximum load limits in impaired watersheds. Historically, grants have been awarded in the range of \$25,000 to \$350,000 per project.

Production Incentives

Self-Generation Incentive Program (SGIP): The California Public Utilities Commission (CPUC) requires utilities to provide financial incentives to customers who install distributed generation under the SGIP program. Customers of four utilities were eligible to apply – Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E). The program includes a tiered funding system, with Level 1 funding of up to \$4,500 per kW for digester gas fuel cells system (capped at 50% of the capital cost) and Level 3 for digester gas at \$1,5000 per kW (capped at 40% of the capital cost). The program started from 2001 and ended in 2008. Several farms were funded through this grant.

Feed-in-Tariff: California requires that all investor-owned utilities and publicly-owned utilities with more than 75,000 customers make standard feed-in-tariff contracts available to their customers. Eligible customer-generators can enter into 10-, 15-, or 20-

year contracts for the utility to buy the electricity produced by small renewable energy systems at time-differentiated market-based prices. The renewable energy systems must be three megawatts or less, and once the statewide capacity of eligible installed generators reaches 750 MW, then the tariffs will no longer be available. Because these contracts are intended to help utilities meet California's RPS, all green attributes of the energy produced, including renewable energy credits, transfer to the utility with sale. Finally, any customer-generator who sells power to the utility under this program will not be eligible to participate in other state incentive programs.

Southern California Edison Company (SCE) Biomass Standard Contract:

SCE offers another contract guarantee specifically for its customer-generators who use biomass as their fuel source. Three different contract options are available to the generators with eligible biomass energy systems: (1) facilities with capacities of less than 1 MW, (2) facilities with capacities of 1MW and up to 5 MW, and (3) facilities with capacities greater than 5 MW but equal to or less than 20 MW. SCE will purchase the electricity produced by these generators at the rate that was available when the facility came online for the entire duration of their contract period. The contract term, though negotiable, is generally for ten, fifteen, or twenty years.

Loans

State Assistance Fund for Enterprise, Business, and Industrial Development

Corporation: Energy Efficiency Improvements Loan Fund (SAFE-BIDCO): Farms that have a net worth of \$6 million or less, and a net income of \$2 million or less can apply for a loan under this program. SAFE-BIDCO provides, among other things, low interest loans—set at the Wall Street Journal's prime rate—for the design, consulting fees, material and equipment costs of anaerobic digesters. The maximum loan amount is \$350,000 at four percent interest with a five-year repayment period.

Municipal Energy Districts (Local Option): Property-Assessed Clean Energy (PACE) is a bipartisan initiative, based at the local-government level, which encourages energy efficiency and use of renewable energy in homes and commercial buildings by providing long term funding from private capital markets at low costs. The amount borrowed is repaid over a number of years through a special property tax assessment, so funding for this program is based on property taxes, and not on additional taxes or government subsidies. In 2008, California passed a law authorizing local governments to offer PACE financing on a voluntary basis—so it is not offered in all Californian municipalities. In 2010,

California also mandated that a PACE reserve program be established, to reduce the overall program costs. To be eligible, property owners must have a clear title to their property, and must be up-to-date on all property taxes and mortgages. The local governments have wide discretion about the criteria used to determine which projects are eligible for the funding, but the California Energy Commission does recommend certain areas of focus. Unfortunately, in July 2010, the Federal Housing Financing Agency issued a statement in which it called into question the senior lien status of most PACE programs, and so most PACE programs have been suspended until further clarification is provided.

Taxes

Sales Tax Exemption for Alternative Energy Manufacturing Equipment: In 2010, California passed SB 71, which, among other things, allows facility owners to apply to the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) to be exempt from sales taxes for expenses related to the design, manufacture, production, or assembly of renewable energy equipment. CAEATFA considers a number of factors in determining the projects that should be granted the exemption, including the benefit of the state in relation to the benefit of the company, and the environmental benefits of the project for California. CAEATFA is allowed to award \$100 million in exemptions annually, as of right, and once this amount is reached must write provide the legislature with 20-days notice prior to approving any more projects. This incentive is to remain in place until January 2, 2021.

4. New York Government Funding

Grants

AEM Agricultural Nonpoint Source (NPS) Abatement and Control Grant: This grant gives financial assistance to farmers with agriculture related water pollution prevention. Farmers must be represented by their County Soil and Water Conservation District to apply for the grant. The New York State Soil and Water Conservation Committee and the Department of Agriculture and Markets oversee the allocation of these funds on a semi-annual basis.

Production Incentives

RPS Customer-Sited Tier Regional Program: Beginning in March 2011, NYSERDA began offering incentives to biogas electricity generators larger than 50kW that are located in certain regions of the state. The program is part of the state's RPS program, and funded by the RPS surcharge collected on the electricity bills of customers of the state's major investor-owned utilities. The incentive is based on expected and actual energy production. Eligible generators must apply to the program by submitting a bid to NYSERDA in the form of \$/kilowatt-hour as an incentive request. The incentives are limited to 50% of the installed costs of the equipment and \$3 million per applicant per round. Projects that are selected to receive incentive payments receive both up-front payments and production payments according to a specific schedule. The first payment is received when all major equipment has been transported to the site, the second payment is received when the project has connected to the grid and been proven capable of producing performance data, and the remaining payments are based on production. The amount of the payments will be based on a percentage of the incentive bid times the estimated energy production over the course of three years. Any selected applicant must conduct an energy efficiency assessment to identify possible improvement measures related to electricity use. Although only two funding rounds have been publicized thus far, the program has been approved through 2015.

Anaerobic Digester Gas-to-Electricity Rebate and Performance Incentive (Expired 12/31/2010): This program incentivized small sized electricity generation for the electricity to be used primarily at the electric customer's location. This program was designed with both a capacity and a performance based incentive, and was a part of the state RPS program. This program is unlikely to be renewed, because it has been replaced by the RPS Customer-Sited Tier Regional Program, and is only included here to demonstrate that New York has a history of incentivizing AD energy generation.

Loans

Municipal Sustainable Energy Programs (Local Option): New York has authorized municipalities to implement the same PACE program that has been authorized in California and a description of the program can be seen in Chapter X. In New York, these loans can be used for energy audits, cost-effective and permanent energy improvements, renewable energy feasibility studies, and the installation of renewable energy systems. The New York State Energy Research and Development Authority (NYSERDA) has established

statewide criteria that participants must comply with, but municipalities also have wide discretion to establish their own standards and eligibility requirements. Loans may not exceed 10% of the value of the property on which the improvements take place, or the cost of the improvements. Also, in New York, the municipalities may elect to fund these programs through federal assistance, instead of providing for repayment through a charge on real estate taxes.

Taxes

Renewable Energy System Exemption: New York authorizes local governments the option of exempting from real estate taxes the increase in the value of property that has been improved by the installation of an AD facility. Unless disallowed by a local government, agricultural facilities do not have to be concerned with an increase in property taxes due to becoming an electricity generator using biomass and AD. Eligible facilities must be 400 kilowatts or less and systems must be connected to the electric grid and operated in accordance with the state's net metering law. The amount of the exemption is equal to the increase in assessed value attributable to the farm-waste AD system. The program was recently extended until December 31, 2014.

5. Massachusetts Government Funding

Grants

Agricultural Energy Grant Program (Ag Energy): Ag Energy provides funds to help Massachusetts farms become more environmentally and economically sustainable by transitioning alternative clean energy technologies. This grant places a priority on projects that involve implementing energy upgrades for existing infrastructure, but can also be used to invest in energy production including "bio-fuel production." There is a \$30,000 maximum award.


Agricultural Environmental Enhancement Program (AEEP): AEEP funding is intended to help farms adopt mitigation and prevention practices to avoid the negative environmental impacts that can be caused by their agricultural business. The focus of the improvement projects should be related to protecting water quality and/or conservation, air quality, or reduction of GHG emissions. An agricultural AD facility could qualify for this funding. The maximum award is \$30,000, though typical awards range from \$10,000

to \$15,000. Each award requires 5% matching funds from the project. The AEEP program funding is separate from the Ag Energy funding, however, it must be applied for through the Ag Energy Grant Program.

Appendix J:

Vermont DEC General Permit

Notice of Intent to Comply with MFO General Permit (Source VT DEC)



STATE OF VERMONT

DO NOT FILL OUT THIS SECTION
FOR AGENCY USE ONLY

Latitude _____ Longitude _____

MFO Permit Number _____

AGENCY OF AGRICULTURE, FOOD & MARKETS
ARMES & Laboratories Division

Notice of Intent to Comply (NOIC)
For coverage under the Vermont Medium Farm Operation (MFO) General Permit

A. OWNER/OPERATOR INFORMATION

Owner Name _____ Operator Name _____

Business Name _____ Phone _____

Farm Physical Location _____

City _____ State |__| |__| Zip Code _____

Farm Mailing Address _____

City _____ State |__| |__| Zip Code _____

Email _____

B. FARM/OPERATION INFORMATION

Type	Number Of Animals
[200-699] Mature Dairy Cows (milked or dry)	
[300-999] Youngstock or Heifers	
[300-999] Veal Calves	
[300-999] Cattle and Cow/Calif pairs	
[750-2,499] Swine (55 lb. or more)	
[3,000-9,999] Swine (under 55 lb.)	
[150-499] Horses	
[3,000-9,999] Sheep or Lambs	
[16,500-54,999] Turkeys	
[9,000-29,999] Chickens (w/liquid system)	
[25,000-81,999] Chickens (w/out liquid system)	
[1,500-4,999] Ducks (w/liquid system)	
[10,000-29,999] Ducks (w/out liquid system)	

☐ Please check here if your operation is ABOVE the animal number criteria listed (LFO)

☐ Please check here if your operation is BELOW the animal number criteria listed (SFO)

☐ Please check if your farm is a Small Farm Operation seeking coverage under the MFO general permit

C. NUTRIENT MANAGEMENT PLAN (which meets state MFO requirements)

- Has a nutrient management plan been developed for this location? ☐ Yes ☐ No
- Is a nutrient management plan being implemented for the farm? ☐ Yes ☐ No
- If no, when will the nutrient management plan be developed? Date: _____
- If not land applying, describe alternative use(s) of manure, compost and other wastes: _____
- How many tons of manure, compost and other wastes produced by the MFO will be transferred annually to other persons? _____ tons/gallons (circle one)

D. TYPE OF CONTAINMENT, STORAGE AND CAPACITY

Type of Storage/Containment	Estimated # of Days of Storage	Total Capacity (gallons/tons)	Have you Received Cost Share for the Storage/Containment
<input type="checkbox"/> Liquid Waste/Manure Storage			<input type="checkbox"/> Yes <input type="checkbox"/> No
<input type="checkbox"/> Semi-Solid Waste/Manure Storage			<input type="checkbox"/> Yes <input type="checkbox"/> No

Other Waste Management	To Manure Storage	Other	No System	Have you Received Cost Share for the Storage/Containment
<input type="checkbox"/> Milkhouse Waste/ Processed Wastewater				<input type="checkbox"/> Yes <input type="checkbox"/> No
<input type="checkbox"/> Silage Leachate System				<input type="checkbox"/> Yes <input type="checkbox"/> No
<input type="checkbox"/> Barnyard Runoff System				<input type="checkbox"/> Yes <input type="checkbox"/> No
Clean Water Diversion System Installed				<input type="checkbox"/> Yes <input type="checkbox"/> No
Animals confined within the production area have access to waters of the state				<input type="checkbox"/> Yes <input type="checkbox"/> No

E. SIGNATURE

I _____ am filing notice of my intent to comply with the General Permit for Medium Farm Operations for the State of Vermont issued by the Vermont Agency of Agriculture, Food and Markets. I have a copy of the General Permit for Medium Farm Operations for the State of Vermont. I have read the General Permit for Medium Farm Operations for the State of Vermont, and I will comply with all of the provisions therein. I certify that I have examined the information submitted in this notice and all attachments, and that the information contained herein is true, accurate and complete.

Signature of Applicant:	Date:
-------------------------	-------

For coverage, a complete and accurate NOIC must be submitted to:

MFO Permitting Program
The Vermont Agency of Agriculture, Food and Markets
Agricultural Resource Management, Environmental Stewardship and Laboratories Division (ARMES)
116 State Street, Drawer 20
Montpelier, VT 05620-2901

(802)828-6908 • (802)828-1397 • (802)828-0459

Appendix K:

Vermont Permitting and Registration Fee Schedules

STATE OF VERMONT
Agency of Natural Resources
Department of Environmental Conservation
Air Pollution Control Division



Permitting and Registration Fee Schedules

Permit to Construct Fees		
Base Fee Schedule	Type of Application	Fee Amount
Permit Application	Major	\$12,500
	Non-Major (also see supplemental fees below)	\$1,000
Minor Amendments	Administrative/Transfer of Ownership	\$100
Supplemental Fee Schedule for Non-Majors		Amount
Engineering Review		\$1,750
Air Quality Impact Evaluation (Modeling)		\$1,250
Observe and Review Stack Emission Testing		\$1,750
Review and Audit Performance of Continuous Emissions Monitors (CEMS)		\$1,750
Review and Audit Performance of Ambient Air Monitors		\$1,750
Implement Public Comment Requirements		\$500

Annual Registration Fee Schedule	
Category	Fee Amount
For facilities with annual aggregate emissions of all air contaminants greater than 5 tons but less than or equal to 10 tons.	\$0.024 per pound of emissions of SO ₂ , PM, CO, NO _x , and Hydrocarbons.
For facilities with annual aggregate emissions of all air contaminants greater than 10 tons.	\$1,000 base fee, <u>plus</u> \$0.024 per pound of emissions of SO ₂ , PM, CO, NO _x , and Hydrocarbons.
Hazardous Air Contaminant Surcharge Fees assessed based on emissions with regard to public health. Please consult the Air Division for type definitions.	Excludes emissions from combustion of fuels except for "solid waste" fuel. Fees are per pound of each compound emitted. Carcinogens (high potency): \$10.00 Carcinogens (low potency): \$0.55 Chronic (high potency): \$0.02 Chronic (low potency): \$0.15 Irritant: \$0.008
Hazardous Air Contaminant Surcharge Fees assessed based on amount of fuel burned annually.	Coal: \$0.43 per ton Wood: \$0.103 per ton Wood w/ ESP and NO _x tech: \$0.025 #6 Fuel oil: \$0.0005 per gallon #4 Fuel oil: \$0.0004 per gallon #2 Fuel oil: \$0.0002 per gallon Waste oil: \$0.0005 per gallon LPG: \$0.0002 per gallon Natural gas: \$0.87 per million FT ³

Permitting and registration fees are as set forth in 3 V.S.A. §2822(j)(1). Permit to construct fees last amended/effective July 1, 2010. Annual registration fees last amended/effective July 1, 2010. Hazardous air contaminant surcharges last amended/effective July 1, 2010. Hazardous air contaminant surcharges for fuels last amended/effective July 1, 2010.

All fees should be made payable to the "State of Vermont – Air Pollution Control Division" and mailed to:

Air Pollution Control Division
103 South Main Street
Building 3 South
Waterbury, VT 05671-0402

Appendix L:

Vermont's Standard Offer Program

Vermont's SPEED Program

In June 2005, the Vermont Legislature enacted the Sustainably Priced Energy Enterprise Development (SPEED) Program within 30 V.S.A. § 8005 and § 8001. The SPEED Program is implemented through the Vermont Public Service Board and applies to electric distribution, transmission, and eligible in-state generation facilities.¹ A new project that uses SPEED resources to produce energy is considered a SPEED project.² SPEED resources are defined as renewable fuels. Examples of these resources are wind farms, hydroelectric projects of less than 200 megawatts (MW), landfill gas-to-energy projects, and select combined heat and power projects.

The new law aimed to encourage the cultivation of renewable fuel development in the state. Similar to a voluntary Renewable Portfolio Standard, SPEED aimed to persuade utilities to include renewable resources within their collections, so that Vermont's citizens, particularly the ratepayers, would receive the economic benefits. Primarily administered by Vermont's Public Service Board (PSB), SPEED has a stated mission of producing all new load growth in the state from January 1, 2005 to July 1, 2012 via renewable fuel resources that are not net-metered.

The Vermont Standard Offer Program

The Vermont Energy Act of 2009 expanded the SPEED Program to include feed-in-tariffs, and effectively established the first statewide feed-in-tariff (FIT) program in the United States. By definition, FITs stipulate that utilities must purchase electricity from renewable sources at a premium. The SPEED Program requires that a "utility which is the interconnecting utility to a SPEED project with an installed capacity of two hundred fifty kilowatts or less shall purchase electricity products offered by the SPEED project."³

The SPEED Program provides that FITs can be established through: (1) the administration of the SPEED Facilitator;⁴ (2) voluntary contracting between one or more

1 VT ADC 18-1-12:4.301

2 VT ADC 18-1-12:4.302

3 Unless (1) the capacity of the project would constitute more than 10% of the peak load of the interconnecting utility or (2) the owner of the SPEED project elects to sell to a different purchaser or execute the standard contract offered by the SPEED Facilitator under section 4.308(F). VT ADC 18-1-12:4.309

4 The SPEED Facilitator is a PSB appointee whose main purpose is to provide information on SPEED

utilities and one or more SPEED project owners; (3) the purchase and sale of electricity from a SPEED project to a utility by the SPEED Facilitator; and (4) the purchase and sale of electricity from a SPEED project into the regional market.⁵ Labeled a Standard Offer Contract mechanism, the FIT program in Vermont has long-term, typically 20-year, contracts and fixed rates meant to provide a suitable return on equity for developers of SPEED resources. The fixed rate for electricity from SPEED projects is required to be less than the anticipated market price for those products, considering anticipated market prices, the then-current market price for forward power contracts for the longest term available in the market, and any adjustment appropriate to reflect material differences between the contract for SPEED project output and forward power contracts.

FITs may only provide for rates equal to the rate fixed by the PSB, unless the contract was formed prior to the Vermont Energy Act and has the consent of the PSB. Contracted rates are differentiated among the technology employed, size of the technology capacity (in the case of wind farms), and costs of production. Ratepayers, rather than taxpayers, shoulder the costs of the program.

The technologies included in the program are Landfill Methane, Farm Methane (also known as agricultural biogas), Wind (15 kilowatt (kW) or less), Wind (over 15 kW), Solar Photovoltaic (PV), Hydropower, and Biomass. No project can exceed 2.2 MW, and no one technology can comprise more than 25% of the total capacity cap of 50 MW.

The PSB determined the original prices per MW hour (MWh) of energy produced for each technology by September 15, 2009, and has since adjusted these rates based on independent testimony, public workshops, and stakeholder evaluation. In addition, utility, producer, and government agency stakeholders participated in a subgroup to advise in the determination of the original and amended rates for all technologies. The Vermont PSB, as established by the legislation, must review and potentially revise the rates for each technology every two years.

Applications for standard offer contracts opened on October 19, 2009, on which solar PV and biomass applications numbered more than the allotted 25% of the total received on the very first day. As such, a lottery was held for producers of these two technologies.

resources and projects to the Board.

5 VT ADC 18-1-12:4.308

Accepted proposals received a standard contract known as the “Vermont SPEED Standard Offer Purchase Power Agreement,” which provides for the long-term sale of power from developers under the SPEED Standard Offer program to Vermont utilities via the SPEED Facilitator.

Farm Methane Projects

Twenty-seven farm-methane projects, of seventy-eight total projects, were originally accepted for processing, four of which have since withdrawn. The twenty-three remaining applicants ranged in project capacity from 40 kW to 1173 kW, with an average of 327 kW per project. As of September 23, 2010, nine total projects were listed in the queue for consideration, but had not yet been processed, one of which was a farm methane developer with a stated capacity of 225 kW. Judging from the monthly billing information for the standard offer program provided by Vermont for December 2010, twelve total standard offer projects are currently up and running, nine of which are farm methane producers. Examples of producers include Berkshire Cow Power, Gervais Family Farm, Chaput Family Farms, and Green Mountain Dairy Farm. For the month of December, these sites produced a range of electricity from 44,745 kWh to 193,787 kWh.

The rate for farm methane resources was originally set at an interim price of 16 cents per kWh. As of January 15, 2010, the standard offer rate for farm methane was listed as \$135.9 per MWh (or \$0.1359 per kWh) for year 1, increasing to \$150.3 per MWh for year 20, accounting for inflation. Of the nine farm methane projects currently underway in Vermont, as referenced above, seven of them are paid \$0.1359/kWh while two receive \$0.1600/kWh, presumably due to the date on which they signed the standard offer contract.

Both of these rates differ from the most recent farm methane model uploaded to the Public Service Board’s “Docket 7533 Establishing Prices by January 15, 2010” in which the Board’s Independent Witness, John Dalton, theorized that an appropriate price for 2011, as year 1, would be \$172.32 per MWh, based on a fixed price component of \$120.62/MWh and escalating price component of \$51.69/MWh. This spreadsheet would appear to be the most updated model available for use by producers considering an application to the Standard Offer program, even though the fixed rates are not consistent with those utilized by the SPEED facilitator.

Though Mr. Dalton’s determination of 17 cents per kWh was not heeded, the cash flow farm methane model nevertheless allows a potential farm producer to gain insight

into the financing mechanics of program participation. The assumptions inputted are for a producer with 300 kW capacity, a net capacity factor of 76.5%, and generation of 2,010 MWh, all of which are expected within the model to remain consistent over the 20 years of a standard offer contract. Of expenses enumerated, operation and maintenance costs and staffing are estimated, allowing one to calculate approximate earnings before interest, taxes, depreciation, and amortization (EBITDA). The model also assumes that tax credits are unavailable for these projects, and incorporates zero revenue from renewable energy credits (RECs) even though farms that possess RECs are permitted to participate. Revenues from REC sales were explicitly excluded from consideration in the rate determination for farm methane projects, at least for the initial stages of the program.

Loans undertaken by farms in the model were estimated by the PSB, based on conventional real estate loans for farms and existing farm methane producers' loans, to possess a term of ten years and an interest rate of 5.5%. Not surprisingly, the after-tax equity return in total cash jumps significantly from year 10 to 11, rising from \$32,035 to \$205,944. The annual after-tax cash flows established enable the model to calculate the internal rate of return earned by the equity investor, which would optimally be 12.13%.

While existing farms were allowed to apply for contracts as long as their farm methane projects were new, existing farm methane projects were originally excluded from the standard offer program. The General Assembly of Vermont enacted house bill 781, No. 159 "An act relating to renewable energy" on June 4, 2010, to address the financial difficulties that existing farm methane projects were experiencing. The existing projects were subject to market energy prices and their associated fluctuations. As of June 8, 2010, existing projects were allowed to apply for standard offers, contingent upon several factors, including that the project possessed a capacity no larger than 2.2 MW. These projects would not count toward the total cap of 50 MW for all new SPEED standard offer projects.

Potential Strengths of Vermont's Standard Offer Program for Farm Methane:

- ◆ Reliable long-term contracts and stability relative to net metering and REC markets
- ◆ Capacity building
- ◆ Increased visibility and awareness
- ◆ Opportunities for education

- ◆ Continuation of Vermont’s “cow power” tradition
- ◆ Diversity of producer size and scale
- ◆ Precedent setting within the United States


Potential Weaknesses of Vermont’s Standard Offer Program for Farm Methane:

- ◆ Inconsistency among rate determinations to generate a feasible, while not excessive, return on equity for producers
- ◆ Low caps for individual technologies, project size, and total program capacity
- ◆ High market entry obstacles relative to net metering processing
- ◆ Inter-agency challenges within Vermont regarding the legality and mechanisms of standard offer contracts
- ◆ Need for rate review every two years
- ◆ Project costs may have been underestimated, particularly regarding land and costs attributed by farmers to dairy production rather than methane production
- ◆ Future machinery, technology, and building repair costs can only be estimated
- ◆ Debt and depreciation model calculations and assumptions have been questioned
- ◆ Timing, financing, and availability challenges associated with incentives and grants

Appendix M:

California Waste Discharge Report


Page 5



**CALIFORNIA ENVIRONMENTAL
PROTECTION AGENCY**

State of California
Regional Water Quality Control Board

**APPLICATION/REPORT OF WASTE DISCHARGE
GENERAL INFORMATION FORM FOR
WASTE DISCHARGE REQUIREMENTS OR NPDES PERMIT**



I. FACILITY INFORMATION

A. Facility:

Name:			
Address:			
City:	County:	State:	Zip Code:
Contact Person:		Telephone Number:	

B. Facility Owner:

Name:		Owner Type (Check One) 1. <input type="checkbox"/> Individual 2. <input type="checkbox"/> Corporation 3. <input type="checkbox"/> Governmental Agency 4. <input type="checkbox"/> Partnership 5. <input type="checkbox"/> Other: _____	
Address:			
City:	State:	Zip Code:	
Contact Person:		Telephone Number:	Federal Tax ID:

C. Facility Operator (The agency or business, not the person):

Name:		Operator Type (Check One) 1. <input type="checkbox"/> Individual 2. <input type="checkbox"/> Corporation 3. <input type="checkbox"/> Governmental Agency 4. <input type="checkbox"/> Partnership 5. <input type="checkbox"/> Other: _____	
Address:			
City:	State:	Zip Code:	
Contact Person:		Telephone Number:	

D. Owner of the Land:

Name:		Owner Type (Check One) 1. <input type="checkbox"/> Individual 2. <input type="checkbox"/> Corporation 3. <input type="checkbox"/> Governmental Agency 4. <input type="checkbox"/> Partnership 5. <input type="checkbox"/> Other: _____	
Address:			
City:	State:	Zip Code:	
Contact Person:		Telephone Number:	

E. Address Where Legal Notice May Be Served:

Address:		
City:	State:	Zip Code:
Contact Person:		Telephone Number:

F. Billing Address:

Address:		
City:	State:	Zip Code:
Contact Person:		Telephone Number:

Form 220 (6/87)

CALIFORNIA ENVIRONMENTAL
PROTECTION AGENCY



State of California
Regional Water Quality Control Board

**APPLICATION/REPORT OF WASTE DISCHARGE
GENERAL INFORMATION FORM FOR
WASTE DISCHARGE REQUIREMENTS OR NPDES PERMIT**



II. TYPE OF DISCHARGE

Check Type of Discharge(s) Described in this Application (A or B):

☐ A. WASTE DISCHARGE TO LAND

☐ B. WASTE DISCHARGE TO SURFACE WATER

Check all that apply:

- | | | |
|---|--|---|
| <input type="checkbox"/> Domestic/Municipal Wastewater Treatment and Disposal | <input type="checkbox"/> Animal Waste Solids | <input type="checkbox"/> Animal or Aquacultural Wastewater |
| <input type="checkbox"/> Cooling Water | <input type="checkbox"/> Land Treatment Unit | <input type="checkbox"/> Biosolids/Residual |
| <input type="checkbox"/> Mining | <input type="checkbox"/> Dredge Material Disposal | <input type="checkbox"/> Hazardous Waste (see instructions) |
| <input type="checkbox"/> Waste Pile | <input type="checkbox"/> Surface Impoundment | <input type="checkbox"/> Landfill (see instructions) |
| <input type="checkbox"/> Wastewater Reclamation | <input type="checkbox"/> Industrial Process Wastewater | <input type="checkbox"/> Storm Water |
| <input type="checkbox"/> Other, please describe: _____ | | |

III. LOCATION OF THE FACILITY

Describe the physical location of the facility.

1. Assessor's Parcel Number(s)
Facility:
Discharge Point:

2. Latitude
Facility:
Discharge Point:

3. Longitude
Facility:
Discharge Point:

IV. REASON FOR FILING

- | | |
|---|---|
| <input type="checkbox"/> New Discharge or Facility | <input type="checkbox"/> Changes in Ownership/Operator (see instructions) |
| <input type="checkbox"/> Change in Design or Operation | <input type="checkbox"/> Waste Discharge Requirements Update or NPDES Permit Reissuance |
| <input type="checkbox"/> Change in Quantity/Type of Discharge <input type="checkbox"/> Other: _____ | |

V. CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

Name of Lead Agency: _____

Has a public agency determined that the proposed project is exempt from CEQA? ☐ Yes ☐ No

If Yes, state the basis for the exemption and the name of the agency supplying the exemption on the line below.

Basis for Exemption/Agency: _____

Has a "Notice of Determination" been filed under CEQA? ☐ Yes ☐ No

If Yes, enclose a copy of the CEQA document, Environmental Impact Report, or Negative Declaration. If no, identify the expected type of CEQA document and expected date of completion.

Expected CEQA Documents:

☐ EIR ☐ Negative Declaration

Expected CEQA Completion Date: _____



**APPLICATION/REPORT OF WASTE DISCHARGE
GENERAL INFORMATION FORM FOR
WASTE DISCHARGE REQUIREMENTS OR NPDES PERMIT**



VI. OTHER REQUIRED INFORMATION

Please provide a COMPLETE characterization of your discharge. A complete characterization includes, but is not limited to, design and actual flows, a list of constituents and the discharge concentration of each constituent, a list of other appropriate waste discharge characteristics, a description and schematic drawing of all treatment processes, a description of any Best Management Practices (BMPs) used, and a description of disposal methods.

Also include a site map showing the location of the facility and, if you are submitting this application for an NPDES permit, identify the surface water to which you propose to discharge. Please try to limit your maps to a scale of 1:24,000 (7.5' USGS Quadrangle) or a street map, if more appropriate.

VII. OTHER

Attach additional sheets to explain any responses which need clarification. List attachments with titles and dates below:

You will be notified by a representative of the RWQCB within 30 days of receipt of your application. The notice will state if your application is complete or if there is additional information you must submit to complete your Application/Report of Waste Discharge, pursuant to Division 7, Section 13260 of the California Water Code.

VIII. CERTIFICATION

"I certify under penalty of law that this document, including all attachments and supplemental information, were prepared under my direction and supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

Print Name: _____

Title: _____

Signature: _____


Date: _____

FOR OFFICE USE ONLY

Date Form 200 Received:	Letter to Discharger:	Fee Amount Received:	Check #:
-------------------------	-----------------------	----------------------	----------

Appendix N:

New York SPDES General Permit

New York State Department of Environmental Conservation Air Permit Application			
DEC ID	APPLICATION ID	OFFICE USE ONLY	
- - - - - - - -	- - - - - - - - - - - -	/ / / / / /	

Section I - Certification

Title V Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons directly responsible for gathering the information (required pursuant to 6 NYCRR 201-8.3(d)) I believe the information is, true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations.

Responsible Official	Title
Signature	Date / /

State Facility Certification

I certify that this facility will be operated in conformance with all provisions of existing regulations.

Responsible Official	Title
Signature	Date / /

Section II - Identification Information

Title V Facility Permit <input type="checkbox"/> New <input type="checkbox"/> Significant Modification <input type="checkbox"/> Administrative Amendment <input type="checkbox"/> Renewal <input type="checkbox"/> Minor Modification General Permit Title: _____	State Facility Permit <input type="checkbox"/> New <input type="checkbox"/> Modification General Permit Title: _____
<input type="checkbox"/> Application involves construction of new facility <input type="checkbox"/> Application involves construction of new emission unit(s)	

Owner/Firm

Name _____

Street Address _____

City _____	State _____	Country _____	Zip _____
Owner Classification: <input type="checkbox"/> Federal <input type="checkbox"/> State <input type="checkbox"/> Municipal <input type="checkbox"/> Corporation/Partnership <input type="checkbox"/> Individual	Taxpayer ID _____		

Facility

• Confidential

Name _____

Location Address _____

• City / • Town / • Village _____ Zip _____

Project Description

• Continuation Sheet(s)

Owner/Firm Contact Mailing Address

Name (Last, First, Middle Initial) _____	Phone No. () _____
Affiliation _____	Title _____ Fax No. () _____
Street Address _____	
City _____	State _____ Country _____ Zip _____

Facility Contact Mailing Address

Name (Last, First, Middle Initial) _____	Phone No. () _____
Affiliation _____	Title _____ Fax No. () _____
Street Address _____	
City _____	State _____ Country _____ Zip _____

New York State Department of Environmental Conservation Air Permit Application



DEC ID									
-									

Section III - Facility Information

Classification					
<input type="checkbox"/> Hospital	<input type="checkbox"/> Residential	<input type="checkbox"/> Educational/Institutional	<input type="checkbox"/> Commercial	<input type="checkbox"/> Industrial	<input type="checkbox"/> Utility

Affected States (Title V Only)					
<input type="checkbox"/> Vermont	<input type="checkbox"/> Massachusetts	<input type="checkbox"/> Rhode Island	<input type="checkbox"/> Pennsylvania	Tribal Land: _____	
<input type="checkbox"/> New Hampshire	<input type="checkbox"/> Connecticut	<input type="checkbox"/> New Jersey	<input type="checkbox"/> Ohio	Tribal Land: _____	

SIC Codes											

Facility Description	<input type="checkbox"/> Continuation Sheet(s)

Compliance Statements (Title V Only)	
<p>I certify that as of the date of this application the facility is in compliance with all applicable requirements: <input type="checkbox"/> YES <input type="checkbox"/> NO</p> <p>If one or more emission units at the facility are not in compliance with all applicable requirements at the time of signing this application (the 'NO' box must be checked), the noncomplying units must be identified in the "Compliance Plan" block on page 8 of this form along with the compliance plan information required. For all emission units at this facility that are operating <u>in compliance</u> with all applicable requirements complete the following:</p> <ul style="list-style-type: none"> This facility will continue to be operated and maintained in such a manner as to assure compliance for the duration of the permit, except those units referenced in the compliance plan portion of Section IV of this application. For all emission units, subject to any applicable requirements that will become effective during the term of the permit, this facility will meet all such requirements on a timely basis. Compliance certification reports will be submitted at least once a year. Each report will certify compliance status with respect to each requirement, and the method used to determine the status. 	

Facility Applicable Federal Requirements								<input type="checkbox"/> Continuation Sheet(s)	
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause

Facility State Only Requirements								<input type="checkbox"/> Continuation Sheet(s)	
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause

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Facility Compliance Certification										Continuation Sheet(s)	
Rule Citation											
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause		
Applicable Federal Requirement		Capping	CAS No.			Contaminant Name					
State Only Requirement			-								
Monitoring Information											
Ambient Air Monitoring				Work Practice Involving Specific Operations				Record Keeping/Maintenance Procedures			
Description											
Work Practice		Process Material					Reference Test Method				
Type	Code	Description									
Parameter							Manufacturer Name/Model No.				
Code		Description									
Limit				Code		Limit Units					
Upper		Lower				Description					
Averaging Method			Monitoring Frequency			Reporting Requirements					
Code	Description		Code	Description		Code	Description				

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Section IV - Emission Unit Information

Emission Unit Description										• Continuation Sheet(s)
EMISSION UNIT	-									

Building					• Continuation Sheet(s)	
Building	Building Name			Length (ft)	Width (ft)	Orientation

Emission Point							• Continuation Sheet(s)
EMISSION PT.							
Ground Elev. (ft)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section		
					Length (in)	Width (in)	
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal	
EMISSION PT.							
Ground Elev. (ft)	Height (ft)	Height Above Structure (ft)	Inside Diameter (in)	Exit Temp. (°F)	Cross Section		
					Length (in)	Width (in)	
Exit Velocity (FPS)	Exit Flow (ACFM)	NYTM (E) (KM)	NYTM (N) (KM)	Building	Distance to Property Line (ft)	Date of Removal	

Emission Source/Control							• Continuation Sheet(s)
Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type	Manufacturer's Name/Model No.	
					Code	Description	
Design Capacity	Code	Design Capacity Units			Waste Feed		Waste Type
		Description			Code	Description	Description
Emission Source ID	Type	Date of Construction	Date of Operation	Date of Removal	Control Type	Manufacturer's Name/Model No.	
					Code	Description	
Design Capacity	Code	Design Capacity Units			Waste Feed		Waste Type
		Description			Code	Description	Description

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Section IV - Emission Unit Information (continued)

Process Information										• Continuation Sheet(s)			
EMISSION UNIT		-								PROCESS			
Description													
Source Classification Code (SCC)		Total Thruput				Thruput Quantity Units							
		Quantity/Hr		Quantity/Yr		Code		Description					
<ul style="list-style-type: none"> • Confidential • Operating at Maximum Capacity • Activity with Insignificant Emissions 		Operating Schedule		Building		Floor/Location							
								Hrs/Day		Days/Yr			
Emission Source/Control Identifier(s)													
EMISSION UNIT		-								PROCESS			
Description													
Source Classification Code (SCC)		Total Thruput				Thruput Quantity Units							
		Quantity/Hr		Quantity/Yr		Code		Description					
<ul style="list-style-type: none"> • Confidential • Operating at Maximum Capacity • Activity with Insignificant Emissions 		Operating Schedule		Building		Floor/Location							
								Hrs/Day		Days/Yr			
Emission Source/Control Identifier(s)													

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Section IV - Emission Unit Information (continued)

Emission Unit	Emission Point	Process	Emission Source	Emission Unit Applicable Federal Requirements • Continuation Sheet(s)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
-													
-													
-													
-													

Emission Unit	Emission Point	Process	Emission Source	Emission Unit State Only Requirements • Continuation Sheet(s)									
				Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause
-													
-													
-													
-													

Emission Unit Compliance Certification • Continuation Sheet(s)									
Rule Citation									
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause
• Applicable Federal Requirement			• State Only Requirement			• Capping			
Emission Unit	Emission Point	Process	Emission Source	CAS No.		Contaminant Name			
-				-		-			
Monitoring Information									
<ul style="list-style-type: none"> Continuous Emission Monitoring Intermittent Emission Testing Ambient Air Monitoring 				<ul style="list-style-type: none"> Monitoring of Process or Control Device Parameters as Surrogate Work Practice Involving Specific Operations Record Keeping/Maintenance Procedures 					
Description									
Work Practice Type	Code	Process Material Description				Reference Test Method			
Parameter		Description				Manufacturer Name/Model No.			
Code									
Limit		Limit Units							
Upper		Lower		Code	Description				
Averaging Method		Monitoring Frequency		Reporting Requirements					
Code	Description	Code	Description	Code	Description				

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Section IV - Emission Unit Information (continued)

Determination of Non-Applicability (Title V Only)										Continuation Sheet(s)
Rule Citation										
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause	
Emission Unit	Emission Point	Process	Emission Source			<ul style="list-style-type: none"> Applicable Federal Requirement State Only Requirement 				
-										
Description										
Rule Citation										
Title	Type	Part	Sub Part	Section	Sub Division	Paragraph	Sub Paragraph	Clause	Sub Clause	
Emission Unit	Emission Point	Process	Emission Source			<ul style="list-style-type: none"> Applicable Federal Requirement State Only Requirement 				
-										
Description										
Process Emissions Summary										Continuation Sheet(s)
EMISSION UNIT		-					PROCESS			
CAS No.	Contaminant Name				% Thruput	% Capture	% Control	ERP (lbs/hr)	ERP How Determined	
-	-									
PTE					Standard Units	PTE How Determined	Actual			
(lbs/hr)	(lbs/yr)	(standard units)		(lbs/hr)			(lbs/yr)			
EMISSION UNIT		-					PROCESS			
CAS No.	Contaminant Name				% Thruput	% Capture	% Control	ERP (lbs/hr)	ERP How Determined	
-	-									
PTE					Standard Units	PTE How Determined	Actual			
(lbs/hr)	(lbs/yr)	(standard units)		(lbs/hr)			(lbs/yr)			
EMISSION UNIT		-					PROCESS			
CAS No.	Contaminant Name				% Thruput	% Capture	% Control	ERP (lbs/hr)	ERP How Determined	
-	-									
PTE					Standard Units	PTE How Determined	Actual			
(lbs/hr)	(lbs/yr)	(standard units)		(lbs/hr)			(lbs/yr)			

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Section IV - Emission Unit Information (continued)

EMISSION UNIT		Emission Unit Emissions Summary				• Continuation Sheet(s)	
CAS No.		Contaminant Name					
-							
ERP (lbs/yr)		PTE Emissions		Actual			
		(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)		
CAS No.		Contaminant Name					
-							
ERP (lbs/yr)		PTE Emissions		Actual			
		(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)		
CAS No.		Contaminant Name					
-							
ERP (lbs/yr)		PTE Emissions		Actual			
		(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)		
CAS No.		Contaminant Name					
-							
ERP (lbs/yr)		PTE Emissions		Actual			
		(lbs/hr)	(lbs/yr)	(lbs/hr)	(lbs/yr)		

Compliance Plan												• Continuation Sheet(s)	
For any emission units which are <u>not in compliance</u> at the time of permit application, the applicant shall complete the following													
Consent Order			Certified progress reports are to be submitted every 6 months beginning ____ / ____ / ____										
Emission Unit	Process	Emission Source	Applicable Federal Requirement										
			Title	Type	Part	Sub Part	Section	Sub Division	Parag.	Sub Parag.	Clause	Sub Clause	
-													
Remedial Measure / Intermediate Milestones											R/I	Date Scheduled	

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Section IV - Emission Unit Information (continued)

Request for Emission Reduction Credits										• Continuation Sheet(s)															
EMISSION UNIT		-								Emission Reduction Description															
Contaminant Emission Reduction Data																									
Baseline Period										/		/		to		/		/		Reduction					
																		Date		Method					
CAS No.					Contaminant Name										ERC (lbs/yr)										
															Netting							Offset			
-					-																				
-					-																				
-					-																				
Facility to Use Future Reduction																									
Name										APPLICATION ID															
										-															
Location Address																									
• City / • Town / • Village										State				Zip											

Use of Emission Reduction Credits										• Continuation Sheet(s)															
EMISSION UNIT		-								Proposed Project Description															
Contaminant Emissions Increase Data																									
CAS No.					Contaminant Name										PEP (lbs/yr)										
-					-																				
Statement of Compliance																									
<p>• All facilities under the ownership of this "ownership/firm" are operating in compliance with all applicable requirements and state regulations including any compliance certification requirements under Section 114(a)(3) of the Clean Air Act Amendments of 1990, or are meeting the schedule of a consent order.</p>																									
Source of Emission Reduction Credit - Facility																									
Name										PERMIT ID															
										-															
Location Address																									
• City / • Town / • Village										State				Zip											
Emission Unit		CAS No.			Contaminant Name										ERC (lbs/yr)										
															Netting							Offset			
-		-			-																				
-		-			-																				
-		-			-																				

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Supporting Documentation

- P.E. Certification (form attached)
- List of Exempt Activities (form attached)
- Plot Plan
- Methods Used to Determine Compliance (form attached)
- Calculations
- Air Quality Model (____ / ____ / ____)
- Confidentiality Justification
- Ambient Air Monitoring Plan (____ / ____ / ____)
- Stack Test Protocols/Reports (____ / ____ / ____)
- Continuous Emissions Monitoring Plans/QA/QC (____ / ____ / ____)
- MACT Demonstration (____ / ____ / ____)
- Operational Flexibility: Description of Alternative Operating Scenarios and Protocols
- Title IV: Application/Registration
- ERC Quantification (form attached)
- Use of ERC(s) (form attached)
- Baseline Period Demonstration
- Analysis of Contemporaneous Emission Increase/Decrease
- LAER Demonstration (____ / ____ / ____)
- BACT Demonstration (____ / ____ / ____)
- Other Document(s): _____ (____ / ____ / ____)
 _____ (____ / ____ / ____)
 _____ (____ / ____ / ____)
 _____ (____ / ____ / ____)
 _____ (____ / ____ / ____)
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 _____ (____ / ____ / ____)
 _____ (____ / ____ / ____)
 _____ (____ / ____ / ____)

Appendix O:

Levels of Attainment for New York Air Quality Control Regions

Levels of Attainment for New York Air Quality Control Regions (40 C.F.R. § 81.333)

Air quality control region	Pollutant				
	Particulate matter	Sulfur oxides	Nitrogen dioxide	Carbon monoxide	Photochemical oxidants (hydrocarbons)
Adirondack Park Intrastate	I	I	III	III	I
Champlain Valley Interstate	II	II	III	III	III
Central New York Intrastate	I	II	III	I	I
Genesee-Finger Lakes Intrastate	II	II	III	III	I
Hudson Valley Intrastate	I	II	III	III	III
Southern Tier East Intrastate	II	II	III	III	III
Southern Tier West Intrastate	II	II	III	III	III
New Jersey-New York-Connecticut Interstate	I	I	I	I	I

* I – Nonattainment Area; II- Attainment Area; III – Unclassifiable Area

Appendix P:

Acronyms

AAP – Accepted Agricultural Practices

AAPs – Vermont Accepted Agricultural Practices

AD – Anaerobic Digester

AEEP – Agricultural Environmental Enhancement Program

AFO – Animal Feeding Operation

AQCR – Air Quality Control Region

ARMES – VT DEC Division of Agricultural Resource Management and Environmental

ARMES – VT DEC Agricultural Resource Management and Environmental Stewardship
Division

BACT – Best Available Control Technology

BMP – Best Management Practices

CAA – Clean Air Act

CAFO – Concentrated Animal Feeding Operation

CalEPA – California Environmental Protection Agency

CARB – California Air Resources Board

CDM – Clean Development Mechanism

CEC – California Energy Commission

CEDF – Clean Energy Development Fund

CFR – Code of Federal Regulations

CPA – Comprehensive Plan Application

CPUC – California Public Utilities Commission

CVPS – Central Vermont Public Services

CWA – Clean Water Act

DENA – The German Energy Agency

DG – Distributed Generation

DOE – Department of Energy

DPPP – California Dairy Power Production Program

DPU – Department of Public Utilities

EEG – Renewable Energy Sources Act (Germany)

EEWärmeG – Renewable Energies Heat Act (Germany)

EIR – Environmental Impact Report

EPA – Environmental Protection Agency

EQIP – Environmental Quality Incentives Program

EU – European Union

FERC – Federal Energy Regulatory Commission

FIT – Feed-in-Tariff

FPA – Federal Power Act

GasNZV – Gas Grid Access Ordinance (Germany)

GasNEV – Gas Grid Tariff Ordinance (Germany)

GHG – Greenhouse Gas

IC – Internal Combustion

IRB – Institutional Review Board

ISO – Independent System Operations

ITC – Investment Tax Credit

JI – Joint Implementation Mechanism

LAER – Lowest Achievable Emission Rate

LFO – Large Feeding Operation

LPA – Limited Plan Application

MADE – Massachusetts Dairy Energy

MassDEP – Massachusetts Department of Environmental Protection

MassCEC – Massachusetts Clean Energy Center

MDAR – Massachusetts Department of Agricultural Resources

MFO – Medium Feeding Operation

MSER – Most Stringent Emissions Rate

NAAQS – National Ambient Air Quality Standards

NMP – Nutrient Management Plan

NPDES – National Pollutant Discharge Elimination System

NPS – Non Point Source

NYSDEC – New York State Department of Environmental Conservation

NYSERDA – New York State Energy Research and Development Authority

PTC – Production Tax Credit

PUC – Public Utility Commission

PURPA – Public Utility Regulatory Policies Act

QFs – Qualifying Facilities

RDV – CVPS Renewable Development Fund

REAP – Rural Energy for America Program Grants

REC – Renewable Energy Credits

REL – Renewable Energy Law (China)

RGGI – Regional Greenhouse Gas Initiative

RMB – Reminbi (China)

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Organizations

SAWQS – Stewardship’s Agricultural Water Quality Section

SBC– System Benefits Charge

SEQR – State Environmental Quality Review

SGIA – Small Generator Interconnection Agreement

SGIP – California Self-Generation Incentive Program

SGIP – Small Generator Interconnection Process

SIP – State Implementation Plan

SIRs – Standard Interconnection Requirements

SPDES – NYSDEC State Pollutant Discharge Elimination System

TPY – Tons Per Year

UNFCCC – United Nations Framework Convention on Climate Change

USDA – United States Department of Agriculture

VAAFMM – Vermont Agency of Agriculture, Food, and Markets

VT DEC– Vermont Department of Environmental Conservation

WDR – Waste Discharge Requirement



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