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Economic Feasibility Study of Colorado Anaerobic Digester Projects

Prepared for the Colorado Governor's Energy Office

August 28, 2009

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Grant 09-205

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Ms. Stacey Simms

The Governor's Energy Office

1580 Logan Street, Suite 100

Denver, CO 80203

August 28, 2009

Dear Ms. Sims:

Thank you for the opportunity to conduct an economic feasibility study on anaerobic digestion in Colorado. Enclosed please find the final report, "Economic Feasibility Study of Colorado Anaerobic Digester Projects" (Grant 09-205)

It is my hope that you will find this report to contain a thorough and accurate overview of the policies and economics relevant to anaerobic digestion in Colorado. I have done my best to ensure that the material contained within the report is as accurate as possible, while considering the dynamic science of renewable energy.

It is also my hope that I have contributed towards expanding the use of alternative energy in Colorado, including the use of anaerobic digesters. I have appreciated the opportunity to work on this project and I encourage you to let me know if you have further questions about the information contained within this report.

Respectfully,

Catherine M. Keske, Ph.D.

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1.0 Executive Summary

The purpose of this project was to conduct an economic feasibility study and identification of policies germane to Colorado agricultural and co-digestion anaerobic digestion (AD) projects. The secondary purpose of this project was to compile information relevant to regional AD projects into a centralized reference report. Key findings are as follows:

- **An enterprise budget for a co-digestion AD project reveals that such projects can be profitable in Colorado under a "typical" scenario, when there are no unforeseen problems, although with a low rate of annual return (3.66%).** Unfortunately, technology providers and operational managers report higher variability in the budgetary line items than the "typical scenario" modeled, so budgetary numbers have been calculated for a "poor" economic condition (approximately a 20% reduction in typical values, unless otherwise specified) and a "favorable" economic condition (approximately 20% improvement in typical values, unless otherwise specified). Poor and favorable economic conditions are projected to yield a return of -30.78% and 46.45%, respectively. Budget findings are presented and discussed in Section 6.0.

- **Sensitivity analysis shows that curtailing AD operational costs and increasing AD energy production (either through increased efficiency or improved billing capacity) have the most significant impact on net income.** In this model, a 1% change in AD operating costs will change net revenue by 14.54%. A 1% change in energy production will change net revenue by 11.14%. Sensitivity analysis findings are presented and discussed in Section 6.0.

- **At this time, the following characteristics are most likely to yield economic viability at a Colorado AD project (or justify the capital investment):**

    - Co-digestion or regional digesters.

    - High volume and consistent availability and composition of feedstock.

    - Potential for using the AD unit to offset natural gas costs, rather than to offset electricity costs or depend upon electricity revenues.

    - Imminent legal action due to odors or nuisance lawsuits. As described in Section 4.4, swine operations may also wish to consider implementing AD units as part of a standard operating procedure.

- **Investment in engineering research on technology to accommodate high solids content waste and low humidity environments will likely improve the economic feasibility of AD systems.** As noted in the sensitivity analysis, AD operating costs and energy generation present the most direct impact on net income. Improved technology that can handle dry digestion provides potential to reduce AD operating costs.

- **Policy and infrastructure investment is needed to accommodate alternative energy.** Specific examples, such as a streamlined permitting process and expanded gas pipelines, are discussed in the report.
- **More information specific to Colorado AD and alternative energy projects is desired.** Many of those interviewed for this project stated that, while they found national EPA AgStar tools to be helpful, they would like to see the Colorado Governor's Energy Office expand upon its web-site content to include more reports, information, and decision tools specific to Colorado.

In summary, while there have been national efforts to compile information about AD and co-digestion, Colorado and the Intermountain West possess unique environmental characteristics that affect the economic feasibility of these systems. Low humidity, scarce water resources, western farm management practices, and regional policies are examples of such unique issues. This report provides a detailed look at ways to make AD practices in Colorado more economically feasible. However, additional study would provide more specificity on the economic feasibility of these projects.

Although the state should not necessarily consider policies with the sole purpose of increasing the number of AD projects, infrastructure improvements that support alternative energy projects will likely serve to improve the economic feasibility and success of AD technology.

2.0 **Project Overview**.

2.1 Introduction. This report summarizes work performed under grant (09-205), issued to Colorado State University by the Colorado Governor's Energy Office (GEO) for the purpose of conducting an economic feasibility study and analysis of the policies germane to anaerobic digestion (AD) practices related to agricultural projects in the state of Colorado. The Principle Investigator of the project was Dr. Catherine Keske, Assistant Professor of Agricultural and Resource Economics in the Department of Soil and Crop Sciences. An independent, but related grant from GEO was simultaneously provided to Dr. Sybil Sharvelle, Assistant Professor of Civil and Environmental Engineering, also at Colorado State University. The purpose of Dr. Sharvelle's project was to develop guidelines, design, and construct a pilot unit for two-stage dry waste AD technology at the Colorado Corrections Industry. Economic details of Dr. Sharvelle's project are also presented in this economic analysis report. The grant period for both projects was March 26, 2009-June 30, 2009. Final project reports were due August 29, 2009.

2.2 Project Purpose. The primary purpose of this project was to conduct an economic feasibility study and a review of economic policies and financial practices germane to agriculturally-based AD practices in the state of Colorado and in the Intermountain West. The sites reviewed during this project were either agricultural, food waste, or co-digestion projects. Municipal wastewater projects (with the exception of the AD unit at New Belgium Brewery) were beyond the scope of this study.

The secondary purpose of this project was to compile information relevant to regional U.S. AD projects into a centralized reference report. To date, most of the anaerobic digestion reports have been based upon studies conducted in the eastern United States. Environmental issues and farm/ranching practices relevant to the arid western United States necessitates a more narrow scope in order to improve the likelihood of success. While the list of active projects in the Intermountain West is short, this report aims to summarize, centralize, and organize information relevant to current regional projects.

Specific tasks fulfilled by this project included:

- Enterprise budget and sensitivity analysis for a Colorado co-digestion project.
- Summary of recommendations made by technology providers involved in Colorado AD projects for expanding the use of AD in Colorado.
- Identification and review of policies and practices relevant to establishing AD projects in Colorado.
- Review of six AD projects in Colorado and Wyoming, in stages ranging from pilot to full operation.

- Compilation of cost and revenue of project-specific data for regional AD projects.

2.3 <u>Data Collection Techniques</u>. Interviews with technology providers and agricultural operators were conducted in order to determine the scope of the project and the variables to be included in the economic analysis. Primary financial data used in the enterprise budget and sensitivity analysis were obtained from agricultural project managers and technology providers of Colorado and Wyoming AD projects. Non-financial data, including information on regional policies, were obtained through interviews with technology providers, state and federal agency professional, agricultural operations managers, subject matter experts, and legal database reviews.

Secondary data were used to augment the primary data, and to develop a more complete picture of AD practices in Colorado and the Intermountain West. Sources of secondary data included public websites like the United States Environmental Protection Agency Ag Star Program (U.S. EPA AgStar), and regional technical reports, such as the Stewart Environmental October 2008 dairy industry feasibility study prepared for the Colorado Department of Agriculture. Data from these and other reports are appropriately acknowledged and a complete list of sources is provided in the reference section. While a technical feasibility study was *not* the primary objective of this economic analysis and feasibility study, technical data from these and other reports are presented to support findings from the project.

There are some important limitations to this study, which should be noted. First, the study's short time horizon prevented further exploration of a few important topics and the inclusion of a few important data sources. For example, technology providers and operational managers both expressed a desire to have a better understanding of available financial instruments for carbon offsets. Although the Governor's Energy Office Colorado Carbon Fund does an excellent job of making information available to the public (and Ms. Susan Innis was particularly helpful in the preparation of this report), the public craves more information about this subject than could be summarized in this report. Second, it is also worth noting that future projects should include interviews with utilities companies to feature their perspectives on current and upcoming energy programs and potential policies that have the potential to expand alternative energy practices. Third, the budgeting and sensitivity analysis models are simply based upon data available. As more data emerge, these models can be refined and will become more exact.

3.0 Insights Provided by Colorado AD Technology Providers

3.1 Methodology and Summary. Ten industry professionals from eight companies were interviewed in order to identify the challenges and opportunities for AD in Colorado. These interviews helped to determine the scope of the study. This section summarizes their perspective of the policies that would improve the ease and success of conducting business within the state. For the purposes of this report, this group of professionals is referred to as "technology providers". Technology provider names were provided by GEO as individuals who were involved projects in the state, although to varying degrees. Project stages ranged from proposal/feasibility to completed AD systems. In order to provide more specificity, technology provider interviews were limited to companies and individuals with experience with AD projects in Colorado and Wyoming. The group includes industry business managers, CEOs consultants, and engineers. A summary of the technology providers interviewed, along with updated contact and web site information, is provided in the appendix.

Several of the policies suggested by technology providers (permitting, carbon credits, and nuisance lawsuits) prompted more in-depth review, resulting in dedicated sections in the report. When possible, data from producer interviews and other sources are integrated to validate technology provider observations.

Providers were interviewed by phone, with the exception of Symbios and Stewart Environmental, who were able to participate in an in-person meeting in the Symbios Ft. Collins office. Length of interview times ranged from 30 minutes to two hours. After being given a brief description of the project, technology providers were first interviewed using a closed question format of five questions:

- Tell me about your current experience with projects in Colorado and the Intermountain West.
- In your opinion, what are the challenges and opportunities for AD in Colorado?
- What could improve the rate of success for AD in Colorado?
- Specifically, what policies could Colorado take to make the use of AD technology more widespread?
- What economic considerations do you believe contribute to the success of an AD project?

In order to minimize response bias, the majority of discussion and follow-up questions took place after all five questions were asked. However, in order to facilitate the flow of conversation, follow-up questions were sometimes conducted between questions. The remainder of the discussion was open-ended to allow technology providers to share their insights and experiences with AD systems.

The providers were supportive of the GEO study, and they were open to answering questions and discussing their experiences with AD technology in the Intermountain West. Technology providers made positive suggestions for improving the ease of doing business within the state. Understandably, the providers were somewhat protective (although to varying degrees) of proprietary information, particularly cost data. In order to ensure open dialogue, references and quotes attributable to specific providers have been omitted from this report, at their request.

In general, technology providers were optimistic about the future of waste to energy projects, and felt that AD projects "had a place" among a variety of other environmentally-based solutions to waste management. All of the technology providers affirmed that economic feasibility was an important consideration for AD projects. AD projects are generally not recommended for operations with fewer than 3,500-5,000 dairy cows, and electrical generators presented potentially high repair costs.

Technology providers provided several suggestions about enhancements that could be made to current Colorado policies that would facilitate future alternative energy projects in general, including AD. Most notably, enhancements to utility policies and practices present opportunities for improvements to cost savings and revenue generation of AD systems. On a positive note, the technology providers stated that a few policy refinements could have a large impact on economic feasibility of AD technology and other sources of alternative energy. Technology providers were also optimistic that there is currently a favorable political climate to support policy changes that will favor future alternative energy practices in general, and that AD projects will benefit from such changes.

3.2 <u>AD Policy and Operational Issues Specific to Colorado.</u> As follows is a summary of the main issues identified by technology providers as relevant to AD in the state of Colorado:

3.2.1 Utility policies and practices: Technology providers were unanimous in their opinion that much could be gained by improving utility policies and practices. All stated these concerns without knowing that others reported similar experiences. These concerns were also echoed by operations that were either considering or currently using AD technology. Almost all of the technology providers stated that utility practices posed *the most significant barrier* to the economic feasibility of anaerobic digesters in Colorado. Concerns about utility practices fell into three categories:

A. Net Metering: Although implementation varies, net metering practices are defined as a mechanism to credit customers for energy that they generate on site in excess of their purchased energy consumption. In other words, the supply of energy to the pipeline/grid is used to offset operation demand and to allow producers the opportunity to supply utilities energy. Colorado has several net metering mandates, including updates that have taken place as recently as this year. However, for all practical purposes, it is the view of the technology providers that net metering programs in Colorado have been ineffective.

Practically speaking, there are several net metering programs that are available across the nation. Utility support of such programs varies by state. California-based RCM International noted that an organized meeting between the state energy office and the utilities can iron out expectations and consistent policies that are conductive to net metering, as not all practices are the same. For example, in California, some utilities may charge farms to install the meter for the net metering. In other cases, utilities may take the position that line quality and transformers are inadequate for net metering. Therefore, a net metering agreement between the utilities and the state can set the proper expectations and business practices, and may ultimately help managers of agricultural and co-digestion projects.

RCM International went on to note that states such as New York and Pennsylvania have implemented effective net metering programs, and that Vermont and Wisconsin also have also implemented effective energy programs. Information about the net metering program in Colorado and other states is summarized in the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by North Carolina State University: http://www.dsireusa.org/about/

B. *Inflexible purchasing plans and low demand thresholds*: Most, if not all, Colorado utilities offer producers only a limited number of energy plans and rate structures from which to choose. For most plans, the base demand threshold is low enough that producers incur demand charges each month when the AD unit goes offline for planned or unplanned maintenance. The technology provider concerns were validated by Mr. Doug Derouchey, Manager of Wyoming Premium Farms in Wheatland, Wyoming, whose facility has two AD units[1]. Mr. Derouchey reported that his facility consistently incurs $1,500-$3,000 in monthly base demand charges for electricity each month if the AD unit goes offline for as short as 15 minutes during that month. Mr. Derouchey also noted that his generator is commonly offline for at least

[1] Further details of Mr. Derouchey's operation are noted in his personal interview, and in the budget section of the report.

15 minutes each month for maintenance purposes. Frequently the unexpected maintenance problems occur during peak energy demand times.

Anecdotal experience presented by the technology providers is that Colorado, as an industry, is slow to provide supply/demand initiatives compared to other western states such as Oklahoma, Texas, and California. In contrast to Colorado utility company practices, which strictly inform producers of their rates, California PG&E enables operators to shift to different utility rate structures. Such "open door policies" foster a more favorable environment to generate energy onsite.

Demand-side utility policies that GEO could facilitate that may improve producer cost savings (and effectively lower energy demand charges) include:

- Higher demand thresholds (or tiered demand thresholds).
- Utility plans that specifically accommodate planned periods of AD shut down, even during peak energy times.
- More flexible or customized service plans to accommodate facilities that generate alternative energy. Several formats may be developed and may include options such as tiered demand thresholds, tiered pricing, and off-peak pricing.
- Consistent agreement and cooperation between utility providers and producers about net metering practices.
- Improved implementation of net metering practices.

C. Under-developed infrastructure and policies for supplying farm-based energy to the grid: Lack of infrastructure (such as gas supply pipelines), limited opportunities for net metering, and current utility practices do not foster the supply of energy to the utility companies. As summarized by one technology provider, "The energy industry in Colorado is simply not economically attractive compared to the energy industry in other states, both for electricity and supplying off-farm biogas."

Developing a favorable purchase agreement between alternative energy producers and utility companies has reportedly been difficult in the past in Colorado for both electricity and biogas. Furthermore, while states such as California are mandated to purchase renewable energy, there have only been voluntary alternative energy purchase agreements in Colorado.

Alternative energy mandates have been shown to have mixed economic effects—overall energy costs typically increase and environmental quality does not necessarily improve in early phases (Palmer and Burtraw, 2005). However, investments in infrastructure (particularly pipeline), at strategic locations conducive to cogeneration may have high marginal payoff. For example, in a 2008 report to the Colorado Department of Agriculture, Stewart Environmental identifies locations within both Weld and Morgan counties that have a high enough concentration of dairy cows (greater than 5,000) within a 2-mile radius to support regional anaerobic digesters. Although the Stewart Environmental model was based upon data from a Texas-based operation currently using AD systems, the company is presently working on an economic feasibility study with Symbios for a centralized AD system in the City of Greeley.

Technology providers felt that there was opportunity for research enhancements to improve the efficiency and effectiveness of AD systems. Research to improve the feasibility of dry digestion presents a great deal of opportunity for the arid Intermountain West. This is discussed in greater detail below. Furthermore, as noted by Bill Williams of Altresco International, enhancements to storage capacity and design of an autonomous release system may allow operations to generate power during peak load conditions, opening opportunities to increase facility income by providing peaking generation to the electricity grid. Timed gas release presents the potential to earn producers a much higher energy price, because they are able to supply energy when public energy demand is at its peak (Zimmerle, Keske, and Sharvelle, 2008).

On a final note, if utility companies are willing to market biogas as "green energy generation", it is possible that voluntary consumer support may be able to fund project costs and present profitability. Voluntary payment for on-farm AD is already in place in Vermont with the Central Vermont Public Service's "Cow Power" program (http://www.cvps.com/cowpower/)

In summary, recommended supply policies include:

- Infrastructure development at strategic locations to facilitate cogeneration or community digesters.
- Funding of additional research into energy modeling and engineering design that will improve the volume, timing, and quality of energy supplied to public utilities.

- Promotion of energy as a source of "green energy" to generate voluntary private payments that may fund the necessary infrastructure and program administration for AD technology.

- Improved implementation of net metering practices.

3.2.2 Permitting: The Colorado AD permitting process was noted by many technology providers as another significant barrier to AD projects, in terms of time and expense. Technology providers also reported inconsistencies in the application of rules towards different technology designs. However, compared to other western states, providers described Colorado has having a "mid-range" level of difficulty, and felt that improvements could be made to expedite the permitting process. Because the state permitting process is a regulation that GEO may be able to directly influence, more time was spent on researching how Colorado permitting practices compared to other neighboring states. A comparison between Colorado and other western states is provided in a dedicated "permitting" in Section 4.0. Two specific concerns that technology providers voiced about the Colorado permitting process are:

- The perception is that the permitting process is difficult in Colorado for co-digestion. This is particularly problematic since co-digestion is a key approach to improve AD feasibility.

- There is a stigma associated with being labeled a "waste energy facility" on permitting applications. This stigma could result in a "NIMBY" perception with the general population.

3.2.3 *Operational and Technical Feasibility:* A great deal of useful information about the technical feasibility of AD systems is available at the EPA AgStar website. In addition to these technical feasibility reports, technology providers identified areas that posed specific, timely operational issues for Colorado and suggestions of policies that could improve the operational feasibility of AD. These issues can be categorized into four general areas:

A. Development of Technology to Overcome High Solids Content Waste: High solids content waste is a major barrier that has been identified as unique to Colorado and the arid western United States. Technology providers consistently noted that research dollars spent to study methods for overcoming high solids content waste may provide considerable payback for future implementation of AD technology in the state of Colorado. At the moment, private funding for high solids content research may not yield economic returns for industry, but research conducted at the university level may spark future private sector activity and future use of the technology.

The need to address high solids content waste stems from the fact that, due to limited water supply, dairy producers do not typically flush barns to remove waste and minimize on-site water use. Therefore, the waste generated by typical dairy operations in Colorado has much lower solids content (dirt, rocks, grit) than that generated in other parts of the United States where anaerobic digestion projects have been met with great success. AD technology requires that the waste solids content be at maximum 12% while dairy waste produced in Colorado has been found to contain near 50% solids, even when combined with on-site wastewater. To dilute waste containing 50% solids to 10% solids at a typical dairy with 1000 milking cows would require 20,000 gallons per day of added water. Given water quality and quantity constraints in the state of Colorado, this is not a viable option.

One promising concept for digestion of low moisture waste materials is a two-stage digester (Figure 3.1). Here, hydrolysis takes place in one reactor and methane generation takes place in a second reactor. A small amount of water is percolated over a bed containing low moisture manure and other waste organics. Organics present in the waste leach into the liquid phase and are hydrolyzed by microbial activity. The hydrolyzed organic liquid waste can then be processed through a high rate anaerobic digester, such as a fixed film digester, to generate methane. Some preliminary work conducted by other researchers has shown promise for this technology. According to Sharvelle (2009), researchers have demonstrated that this process can yield up to 125% and 293% methane compared to that of a conventional process. Water can be re-circulated through the hydrolysis reactor until maximum possible organic content is leached into the liquid. Onsite wastewaters would be a sufficient water supply. One problem encountered with the leachate bed is porosity of the waste material and inefficient water flow and distribution throughout the system. Sharvelle reports that in one study, researchers have been able to overcome this problem by the addition of pistachio hulls. Recent work by Sharvelle and Loetscher, funded by the Colorado Governor's Energy Office (2009), used hay, corn stalks, and straw to improve process efficiency.

A full report of Dr. Sharvelle and Loetscher's work was submitted to the Colorado Governor's Energy Office on August 17, 2009. Results from this study will likely be of great interest to technology providers, who are eager to work on a solution to overcome high solids waste that is inherent to Colorado dairy practices.

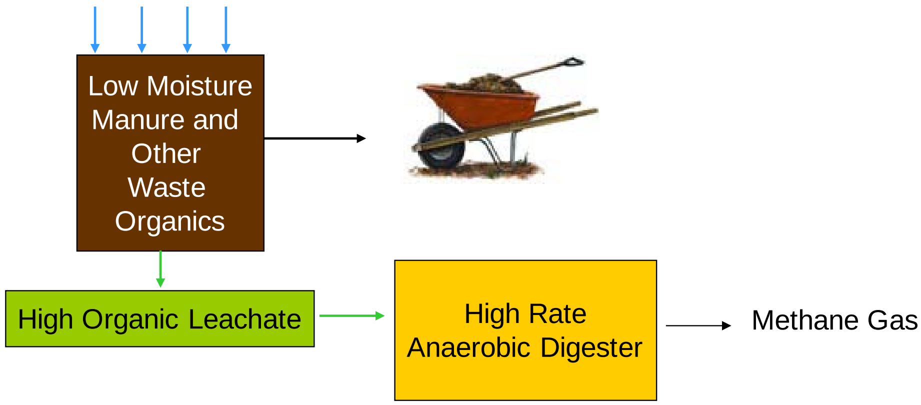

Figure 3.1 Two-Stage Anaerobic Digestion Process

B. Appropriate Volume and Mix of Feedstock: Interviews with both technology providers and producers affirmed that a consistent, chemically balanced level of feedstock is necessary in order to sustain the chemical reaction required to produce bio-methane over time and to reduce AD system maintenance [2]. Several technology providers noted that volume and mix of feedstock is one of the most important factors in determining whether or not an AD project will be successful. Furthermore, technology providers noted that feedstock issues make it challenge to maintain a properly functioning digester at a single farm. One technology provider estimated that a scale of 4,000-5,000 tons of feedstock is required in order to create a sophisticated AD system with industrial controls capable of ensuring smooth operation. Stated the provider, "Single-farm based systems are not sophisticated enough to guarantee consistent operation." Cooperatives, community digesters, and co-digestion offer greater promise for consistent feedstock than independent, farm-level systems, and suggestions for optimal Colorado locations have recently been identified by Stewart Environmental (2008).

C. Reducing the Administrative Burden of Cogeneration: Nearly all technology providers noted that co-digestion and relationships with other industries (such as food processing facilities), are critical make projects profitable and ensure a consistent level of feedstock. This is particularly when an AD operator is able to collect a tipping fee from feedstock providers. Other industries can also benefit from the low odor, reduced emissions, and environmental benefits that can be facilitated

[2] One technology provider, reluctant to provide proprietary financial data, provided the threshold of "3,500 dairy cows" as the minimum level required to justify installation of a system in the state of Colorado. The technology provider estimated that feedlot levels should be a 25,000-30,000 head, considerably higher due to animal dietary needs. Another reference, the 2008 Stewart Environmental report, uses 5,000 dairy cows as an estimated threshold for profitability.

by AD technology. However, energy market volatility has contributed to unstable gasoline, coal, and diesel prices, making the economics of co-digestion challenging, particularly with respect to transportation cost.

For example, high gasoline prices in 2008 discouraged some industries in Texas from transporting waste to AD systems, resulting in disruptions to both feedstock and revenues from tipping fees. In the case of one AD system in Texas, at the conclusion of a 6-month transportation subsidy, the technology provider now pays 50% of transport costs, which breaks down to $40/truckload of manure. In another example, the state of Texas uses $1.35 per gallon of gas as the basis for transportation costs. The state then subsidizes a percentage of the transportation costs when the cost exceeds $2.25 per gallon of gas.

To frame the challenges posed by energy volatility differently, another technology provider estimated that $4.50/gallon diesel would limit feedstock availability to under a 35 mile radius from the digester. In contrast, $2.20/gallon diesel could attract feedstock availability from a 100-mile radius.

In short, the state may be able to minimize AD operator risk by offsetting fuel prices (either per mile or per load) after a pre-determined threshold is reached.

D. Development of Alternative Technologies to Accommodate Waste: Technology providers suggested that research into other waste to energy projects may also reveal effective waste to energy solutions. Technology providers suggested that more research should be conducted on ammonia release/capture techniques with filters, gasification techniques, and methane burn-off.

3.2.4 Economic Opportunities: Technology providers noted that economic viability is a critical factor in the long-term success of AD projects. Although grants, loans, and other forms of assistance are available to producers (and are well-documented by EPA AgStar), technology providers noted that operations that have achieved economic returns on an AD system have achieved success in several of the following areas:

A. Use of AD systems to effectively offset costs: Technology providers noted that the most significant financial opportunity lies not in revenue generation from selling electricity to the grid, but in the ability to offset costs. This observation was echoed by producers and validated in the sensitivity analysis. Examples of significant cost offset include avoidance of legal costs from lawsuits involving nuisance claims and on-site use of biogas for boilers, water, heat recovery, and injections into the pipeline. Those interviewed had mixed reactions of whether or not electricity generation was a net benefit when generator maintenance costs were considered.

Examples of revenue generation and cost offset are presented in the agricultural operation interviews, and are further reviewed in the enterprise budget and sensitivity analysis.

B. Use of AD to leverage future operational expansion: Installation of an AD system can open the door to grow the operation, because controls are already in place to accommodate environmental quality concerns, including odor control. Mike Casper of Microgy noted a case in Wisconsin where a 4,000 head dairy producer with an existing digester was able to more easily double the size of his operation to 8,000 because the technology was in place. Doug Derouchey of Wyoming Premium Farms and Adam Barka of Christensen Farms LLC both acknowledged that part of the intent behind installation of two AD systems was to accommodate expansion. While AD units may accommodate operational expansion, it is important to consider that inappropriately low feedstock availability may make the digester malfunction. When installing a digester, it is important to maintain a balance between expansion goals and current and short-term availability of feedstock.

C. Markets for effluents and environmental goods: Compost, fertilizer, and carbon markets all provide opportunities for revenue generation. Use of an AD system may also help the products become branded as a renewable energy systems, or c*arbon neutral systems*—a title that may provide increasing benefit as eco-labeling becomes more prominent in the food labeling industry.

3.2.5 Capital Financing: All technology providers noted that recent disruptions to the financial markets have affected their ability to secure capital financing for large projects. Economic recession, the collapse of national financial institutions, and the closing of regional banks (such as Greeley's New Frontier Bank), have yielded complex macroeconomic results. Among the macroeconomic effects are high interest rates and difficulty for technology providers and agricultural operations to secure financial capital. Furthermore, the effects of proposed reforms to the financial system are unknown, making it difficult to predict when and to what extent the capital market will rebound. Technology providers report that the most relevant financial impacts on the industry are:

A. Rapid changes in interest rates. For example, two technology providers reported that in mid-2008, tax exempt municipal bonds for $50-$60 million projects were at 7% in Texas and at 9% in California. In November 2008, the interest rate rose to 14%, where it has essentially remained since that time.

B. High interest rates by historical standards.

C. Collapse of New Frontier Bank. The insolvency of New Frontier Bank in Greeley has also had an impact on the ability of producers to secure capital for their operations, as well as large AD projects. The effect of the bank's collapse on northern Colorado is profound, since New Frontier Bank of Greeley bank-rolled many dairies. With significant declines in the price of milk, dairies have had difficulty securing capital to cover operating costs, and many dairies (who might benefit from AD technology) currently face significant financial trouble. Tom Haren, Executive Consultant of Longmont-based AgProfessionals, LLC sees the impact of the New Frontier Bank failure as far-reaching, with the brunt of the negative impacts still on the horizon. States Heron, "There is simply no capital to be had for $10-45 million projects." Although smaller USDA operating loans (typically in the range of $30,000-$40,000 may assist some producers, large agricultural projects that provide a revenue and job base for many communities will be hard to come by in the near future. More information about the collapse of New Frontier bank can be found at: http://www.fdic.gov/BANK/INDIVIDUAL/FAILED/newfrontier.html

Technology provider suggestions for GEO assistance that may help to secure capital for agricultural projects:

- Directing TARP funds into agricultural projects.
- Assist with sources of loan guarantees for the agricultural community.
- State-backed financial bonds for energy projects (lower interest rates or public bond financing of green energy projects).
- Streamlined process by the state for securing private equity

4.0 <u>Permitting, Carbon Markets, and Nuisance Claims</u>.

<u>4.1 Summary</u>. This section summarizes three issues identified by technology providers and producers as having high impact on AD projects: permitting, carbon credits, and nuisance claims. These three issues were mentioned during every interview as areas of concern or opportunity for improving Colorado AD policies; so further time was invested to provide information about these areas. However, an expanded policy summary was beyond the scope of this project. The information in this section merely scratches the surface of each topic, and there is clearly more room for study in each of the three areas. A review of the Colorado utility industry and capital financing solutions would also appropriately round out this type of policy overview.

Additional feedback from technology providers and producers suggested that GEO should continue to update its website with information specific to the state of Colorado. It was also emphasized that key words typed into Google, such as "Colorado, anaerobic digester" should always pull up the GEO website.

<u>4.2 Permitting</u>. Permitting was identified by technology providers to be a considerable barrier to implementing AD systems in the West. In particular, the California and Texas permitting systems were noted by technology providers to be the most cumbersome. This report reviews the permitting process in six states. States other than Colorado were selected for similarities in climate and production practices. In all of these states, the AgStar website indicated that there was either an operating agricultural AD system at one time or high potential for an agricultural AD system in the future.

Without exception, agency professionals involved with AD permitting were ***extremely*** courteous and willing to provide information for the purposes of this study. Agency professionals also had an interest in hearing about the practices in other states. However, the greatest difficulty was in finding the appropriate individual with whom to speak. The typical inquiry required four phone transfers to different individuals within an agency before finding the individual who knew how to handle AD. When multiple offices or agencies were involved with AD permitting within a state (e.g. often times both the air quality permitting division and the water quality permitting division), it was not uncommon for one division to *not* know with whom to speak in the other division about the permitting process.

There is a large variation in the permitting application process between states, and little information about AD is provided on state agency websites, making it difficult for technology providers and producers to seek information. It is clear that there is a large learning curve for the producers, as well as the agencies. While the helpful attitude and professionalism of agency professionals was clear (and a very positive aspect of this project), the time and number of transfers required to locate the "person in the know" could discourage technology providers and producers from pursuing the important information required in order to pursue a system. The general theme from most states was that AD permits for agricultural facilities were much more direct and streamlined compared to the AD permitting process for co-digestion projects. Several states have provided supportive documents to provide insight into their AD permitting process. These documents have been included in the appendix.

With respect to Colorado, Ms. Phyllis Woodford, Manager of the Office of Environmental Integration & Sustainability at the Colorado Department of Public Health & Environment, was very responsive to provide insight into the permitting process. In a matter of two days, she and her staff prepared a summary of the Colorado permitting process for agricultural digestion and co-digestion projects. A copy of this three-page summary is in the appendix. However, despite the staff's helpfulness, in comparison to several other states, the formula for determining permitting fees is complex, and a streamlined permitting/fee process should be considered to encourage AD permitting applications, particularly for co-digestion projects. Nebraska's "Fast Track Program" provides one example of an efficient permitting program. As follows is a brief summary of the permitting practices of six other western states:

4.2.1 California: The AD permitting process in California is unique, because the process essentially begins at the local level. Each county operates somewhat differently, and AD permitting must comply with the local zoning and board requirements. The permitting fees are also dictated at the local level. For example, permitting fees are notably high in Los Angeles County, but are substantially lower in Lassen County. For an AD unit, three separate applications are required: air, water, and environmental/public health. After approval is achieved in all of these areas, the state reviews the permits for final approval. The state typically does not become involved in the process until local approval takes place. Local variability results in differences in approval times. The California Integrated Waste Management Board has provided a guiding document, authored by Mr. Watson Ginn, which outlines the permitting process. This is provided in the appendix.

Contacts at the California Integrated Waste Management Board: Mr. Mark de Bie, Permitting and Enforcement Division Project Manager, MdeBie@ciwmb.ca.gov, 916-341-6300.

4.2.2 Nebraska: Three permits are required in Nebraska for agricultural AD systems: air, water, and waste. However, there are no associated permitting fees. For co-digestion, an industrial water quality permit is required under Title 119. The industrial water quality permit involves an "inconsequential" charge. The Nebraska Department of Environmental Quality (NDEQ) is reviewing a process for streamlining the agricultural waste process to accommodate other co-digestion, including meat packing waste.

The entire permit processing time is estimated to be 180 days, but the process may be more efficient with the recommended "Fast Track Program", which involves the NDEQ early in the process. The Fast Track Program was instituted when ethanol plants were being built at a rapid pace during 2007-2008. The NDEQ urges prospective sources to "contact us early, and contact us often."

NDEQ contacts: Peggy Berlowitz, 402-271-6974; Joe Francis, 402-471-6087.

4.2.3 Texas: Several transfers led to a discussion with the Texas Department of Water Quality Assessment, within the Texas Commission of Environmental Quality. Like Colorado, the permitting process in Texas is complex. The permitting process varies greatly upon the size and type of operation, as well as compliance history. Regional co-digestion projects require an "industrial permit" process. Contact information is as follows:

Office of Permitting and Registration, Main Line: 512-239-2104

Contacts for agricultural AD permitting: Jamie Salaviner/James Moore, 512-239-0171. Contact for co-digestion AD permits: Kelly Holligan, 512-239-2369. Texas Commission on Environmental Quality http://www.tceq.state.tx.us/

4.2.4 Utah: The state of Utah has experience permitting a co-digestion AD unit (Smithfield Bioenergy) and two agricultural operations using AD systems. The Smithfield Farms operation is no longer operational. The Utah AD application process involved obtaining a construction permit and a groundwater discharge permit from the Utah Department of Environmental Quality Division of Water Quality. Although specific details about the permitting process were not provided, Ed Hickey, Environmental Science, Water Quality Division, provided several documents outlining the co-digestion process at Smithfield Bioenergy. These documents, which provide graphical detail of the co-digestion unit, have been included in the appendix. Contact for Utah Department of Environmental Quality, Division of Water Quality: Ed Hickey, 801-536-4400, ehickey@utah.gov

4.4.5 Wyoming: AD units are subjected to permitting for waste water treatment and air quality. There are no fees for the waste water permitting process. Contact: Wyoming Dept. of Environmental Quality, Lou Harmon, Program Manager, 307-777-7088 email: lharmo@wyo.gov.

4.3 Carbon Markets. Carbon markets, and specifically carbon credits traded on the Chicago Climate Exchange, have gained attention for providing revenue opportunities to AD projects. This was particularly the case when the CCX price peaked at a high greater than $7/tonne in May 2008. Recent volatility in the market has now brought prices below $1/tonne. In general, agricultural operators interviewed for this project articulated that they believe that carbon prices will rise over time, but they are trying to "time the market" to receive a consistently high price. The volatility of the carbon market affects net income and is considered in the enterprise budget and sensitivity analysis, where carbon prices are assumed at $5.50/tonne in the baseline scenario.

A full review of carbon policies was started, but the effort proved to be more involved than could be successfully accomplished in the time available. A more thorough analysis and review is recommended for a future phase of study. In the interviews, several agricultural operators and some technology providers expressed puzzlement and viewed accounting process for the credits as "mysterious". This prompted a call to Susan Innis, GEO's Colorado Carbon Fund Program Manager. Ms. Innis was very helpful and provided several informative website links that provided insight into the accounting practices. It is clear that the Colorado Carbon Fund is a valuable resource to the Colorado public and GEO may wish to expand upon services provided by this department. Based upon interviews, there is a desire for additional readable "fact sheets" on carbon policies, particularly with regards to the accounting practices. These outreach documents could be easily posted on the GEO website.

4.4 <u>Legal Costs of Nuisance Claims</u>. During interviews, both technology providers and agricultural operators affirmed that AD units effectively reduce agricultural odors that often prompt nuisance lawsuits. Work by Martin (2003) also notes that AD units can provide a measurable reduction in odor, in addition to playing a role in the management air emissions, water quality, and waste management. Proper management of all of these environmental quality aspects can help to improve neighbor relations and mitigate nuisance lawsuits on agricultural operations. However, when faced with high AD capital investment costs, it can be difficult to determine whether the large investment justifies potential future legal expenses.

While legal costs are frequently calculated in the cost of doing business, the risk associated with an odor-related nuisance lawsuit can be difficult to estimate. The majority of cases are settled outside of court and insurance companies typically subsidize the settlements. Furthermore, when nuisance verdicts are handed down by courts, documentation of the damage awards (which include punitive damages) can be challenging to find. Not all verdicts and settlements are reported. Also, opinions from appellate judges don't routinely mention awards. However, in-depth searches on Westlaw and LexisNexis (two legal databases) provided some insight into nuisance lawsuits related (at least in part) to agricultural odors.

A summary of recent nuisance lawsuit awards and settlements can be found in Figure 4.1, shown below. The cases are ordered by year. Also listed are the states where the lawsuit was filed, case or plaintiff as available, and type of operation. The settlement and damage values (which include punitive damages) have not been corrected for inflation. The type of agricultural operation is listed on the right hand column.

Figure 4.1 Summary of Financial Awards from Agricultural Nuisance Suits

Claims Awarded in Nuisance Suits				
Year	**State**	**Award**	**Plaintiff/Case**	**Operation**
1991	NE	$375,600	Kopecky v. National Farms, Inc.	Swine
1996	KS	$12,100	Settlement—plaintiff/respondent both undisclosed in news article.	Swine
1998	KS	> $15,000	Twietmeyer v. Blocker	Beef feedlot
1999	MO	$5,200,000	Vernon Hanes et al. v. Continental Grain Company	Swine
2001	OH	$19,182,483	Seelke et al. v. Buckeye Egg Farm, LLC and Pohlman	Egg/Poultry
2002	IA	$33,065,000	Blass, McKnight, Henrickson, and Langbein v. Iowa Select Farms	Swine
2004	OH	$50,000,000	Bear et al. v. Buckeye Egg Farm, Anton Pohlman and Croton Farms, LLC	Egg/Poultry
2006	AL	$100,000	Sierra Club, Jones, and Ivey v. Whitaker and Sons LLC	Swine
2006	MO	$4,500,000	Turner v. Premium Standard Farms Inc.; Contigroup Co., Inc.	Swine
2007	IL	$27,000	State of Illinois (Plaintiff). Respondent undisclosed.	Swine

The awards ranged from $12,100-$50,000,000. Seven of the ten reported cases involved swine operations. Two cases involving large awards were against the same owner of two Ohio egg production facilities. There was one example of a settlement to a Kansas cattle feedlot. Six of the documented cases occurred west of the Mississippi.

Blass et al. v. Iowa Select Farms presents the most unusual case, because a high punitive damage award ($32,065,000) was distributed to only four neighboring farm couples. Most large awards of that magnitude involve class action lawsuits. To quote the order, the couples reported having been subject to: "noxious gases, offensive odors and excessive amounts of flies. The couples sued Iowa Select Farms complaining that improperly-disposed-of swine carcasses and unsanitary conditions created health risks. The couples also alleged that Iowa Select willfully and recklessly located the 30,000-hog facility on the

640-acre farm without regard to its impact on neighbors. An expert at trial testified that the farm produced as much excrement as 90,000 to 150,000 people.

In addition to information gathered from legal databases, Mr. Doug Derouchey of Wyoming Premium Farms states that his operation spent approximately $200,000 in legal fees fighting two lawsuits, in which plaintiffs were seeking approximately $2,000,000 in punitive damages.

Although specific conclusions cannot be drawn from this information, the summary of legal information gives insight into general trends that may guide the installation of AD units. First, evidence of large legal awards provides context for the enterprise budget shown in Section 6.0. An imminent lawsuit that could result in more than $5.9 million in damages (including punitive damages) or fines in one year would overcome the maximum losses projected by the "worst case scenario" presented in the enterprise budget. In other words, preventing legal conflict can justify the net losses from an AD project. This finding is consistent with the anecdotal information presented by technology providers and agricultural operators.

Second, many of the nuisance claims on record involve swine operations. Cases with high punitive damage awards also involve swine operations. Furthermore, not all of the nuisance suits occurred in regions with high population pressures, including Mr. Derouchey's operation. Therefore, trend of nuisance suits involving swine operations could persuade swine operations to consider adoption of AD units as a management practice, even when the operation is not located in an urban-rural interface.

5.0 AD Projects in Colorado and Wyoming.

5.1 Summary. The purpose of this section is to provide an update of the current and proposed AD agricultural or co-generation projects in the region. Contacts were obtained from the Colorado Governor's Energy Office, the EPA AgStar website, and technology providers. Interviews with project directors lasted from 30 minutes to four hours. Two project directors (Colorado Correctional Industries and Wyoming Premium Farms) encouraged site visits, and the report contains photos of these visits to provide insight into their operation.

All project directors interviewed were supportive of the GEO study and were willing to provide various levels of financial data. While structured interview questions were attempted, the interviews evolved into an open-ended format, to accommodate the high variation in the level of cost/energy production information that producers were willing to share. Others who have been involved with previous AD feasibility studies were either unavailable or chose not to participate in the project. Of the six projects reviewed, three have operational AD units that employ an electrical generator. Two projects have been involved in recent pilot technical feasibility studies. One project is currently undergoing a technical and economic feasibility study for co-generation.

Rather than restate information found in published reports, the objective of this section is to summarize relevant financial and technical project data and to provide relevant project updates. One downside is that it was difficult to obtain consistent and specific financial and operational data. The values presented merely reflect what project managers were willing to share, and the boundaries that they set for privacy and proprietary information were respected. For example, project managers were more willing to provide cost, rather than revenue, information. Although this appears somewhat imbalanced, this information is valuable and a big picture can be painted when the data are integrated into the sensitivity analysis found in Section 6.0. A list of references that refer to previously published reports can be found in Section 9.0.

As follows is a review of the projects (in alphabetical order):

5.2 Aurora Organic Dairy (Platteville, CO). In 2008, the Colorado Governor's Energy Office supported a technical and economic feasibility study for a plug flow AD project at this site. While installation of an anaerobic digester at the dairy facility was determined to be technically feasible, an economic analysis conducted by showed that installation would not be economically viable. Due to the recent publication date of this technical and economic feasibility report, the operational managers of the Aurora Organic Dairy were not interviewed and no additional analysis was conducted.

The technical feasibility review for the Aurora Organic Dairy project was conducted by Dr. Sybil Sharvelle and Mr. Luke Loetscher of Colorado State University. The economic review and final report were conducted by ActNeutral LLC in Boulder, Colorado. The rate of return (IRR) and net present value (NPV) in the ActNeutral model were both negative (-12.9% and -$1.26 Million, respectively), even with "aggressively beneficial" assumptions for systems costs, energy inflation, and O&M costs. Green house gas reduction market incentives were not applied in this particular case. The report notes that poor economic viability of this particular digester system results from low energy potential of substrates at the dairy and inefficient methane production of plug flow digesters. Co-digestion was also not an option for this particular system, thus limiting future potential revenue streams. A copy of his financial summary taken directly from the final report can be found in the appendix.

In the context of furthering AD projects in Colorado, the Aurora Dairy feasibility study provides a rudimentary protocol and paves the way for future feasibility studies on AD installation at animal feeding operations in Colorado. This report provides insight to guide producers and their advisers entering into the preliminary steps of a feasibility study, and assists with informed decision making.

<u>5.3 Colorado Correctional Industries</u>. Colorado Correctional Industries (CCI) is the entrepreneurial division of the Colorado Department of Corrections. According to the CCI website and CCI Manager of Life Safety Willie Viljoen, CCI has two key objectives. First, train inmates in a trade to improve their likelihood of success upon release. Second, produce high quality products that will support CCI as self sustaining business and cut prison operating costs. While better known as a furniture supplier for state contracts, CCI also has several agricultural industries on its 5,000 acre prison campus in Cañon City, including cow and goat dairies, a horse training program, a canine training program and a tilapia farm. The agricultural focus helps CCI to meet both of its objectives. In contrast to other work environments that are unwilling to hire employees with a criminal history, released inmates may be able to find employment in agriculture upon their release. The agricultural products feed the inmates at several campuses, and some of the industries (such as the he tilapia farm) have proven to be of high commercial value.

CCI is also in a unique position to implement AD technology. High volumes of waste are produced from the diverse agricultural operations. The campus, which includes inmate housing, also requires high volumes of energy. There is also financial incentive for CCI to reduce its energy costs. Although cost and usage data are considered sensitive matters (and were not revealed by CCI) Viljoen believes that waste to energy technology would work effectively at CCI. He states, "We could use every drop of gas and heat onsite. We could use the gas for the boilers in our tilapia plants—which require high temperature. We could even use the gas to heat the boiler water at the prison next to dairy."

CCI was the subject of a GEO-funded pilot plant design for a multiple-stage AD project to handle dry digestion technology. This project was implemented by Dr. Sybil Sharvelle and Mr. Luke Loetscher at Colorado State University. Their final report, submitted to GEO on August 17, 2009, describes the technical feasibility of this type of project at CCI. In their report, Sharvelle and Loetscher note that, "…the ability to generate energy from waste products already requiring post treatment is a key advantage of this system. From a research and technology development standpoint the CCI facility at Cannon [sic] City is the perfect location to model a regional co-digestion energy system" (p. 6).

For the Economic Feasibility Study, Mr. Viljoen, Ms. Diana Dean (CDOC Energy Management Engineer), two managers from the dairy, and a manager from the horse corral participated in a teleconference call to describe their project site and interest in an economic feasibility study of the project. A July 29, 2009 site visit was also conducted for the purposes of understanding the spatial aspects of the operation.

Although little cost and revenue data could be obtained, the site visit was useful to understand the size of the operation and the potential for availability of feedstock from 1,200-2,000 dairy cows, 3,000 horses, 2,000 goats, and other agricultural by-products. From the visit, it was clear that, with some strategic planning, the campus could directly utilize all of the biogas for boiler heat. An electrical generator, revealed to be the source of contention for many other operations, may not be necessary for CCI to offset costs.

Given the size of the facility, the diverse feedstock available, and the ability for CCI to use all of the AD energy generated, much could be learned from an economic feasibility study of CCI. A dedicated economic feasibility study on dry digestion technology may ultimately lead to the expansion of this technology in the arid West. As follows are photos that illustrate several of the agricultural operations at the Cañon City facility.

Photo 5.3.1 CCI Dairy Herd. The CCI dairy herd consists of 1200-2000 cows. Viljoen describes the herd as "one of the purest closed herds" in the United States. Established in 1951, the herd has been contained entirely within the campus, and only receives outside semen for breeding purposes.

Viljoen states that the typical milk production is approximately 12,000 gallons per week. Three-fourths of the milk is sent to a co-op and one quarter of the milk is served to inmates at several facilities. 75,000 ½-pint cartons of milk are typically packaged each month for inmate use.

Photo 5.3.2 and Photo 5.3.3 CCI Horse Training Facility (at left and on next page). These photos show the expansiveness of the 3,000 head horse training facility. The majority of the horses are part of the Wild Horse Inmate Program (WHIP), which teaches inmates to train wild horses that are removed from Bureau of Land Management lands. CCI also offers boarding and training services to the private sector.

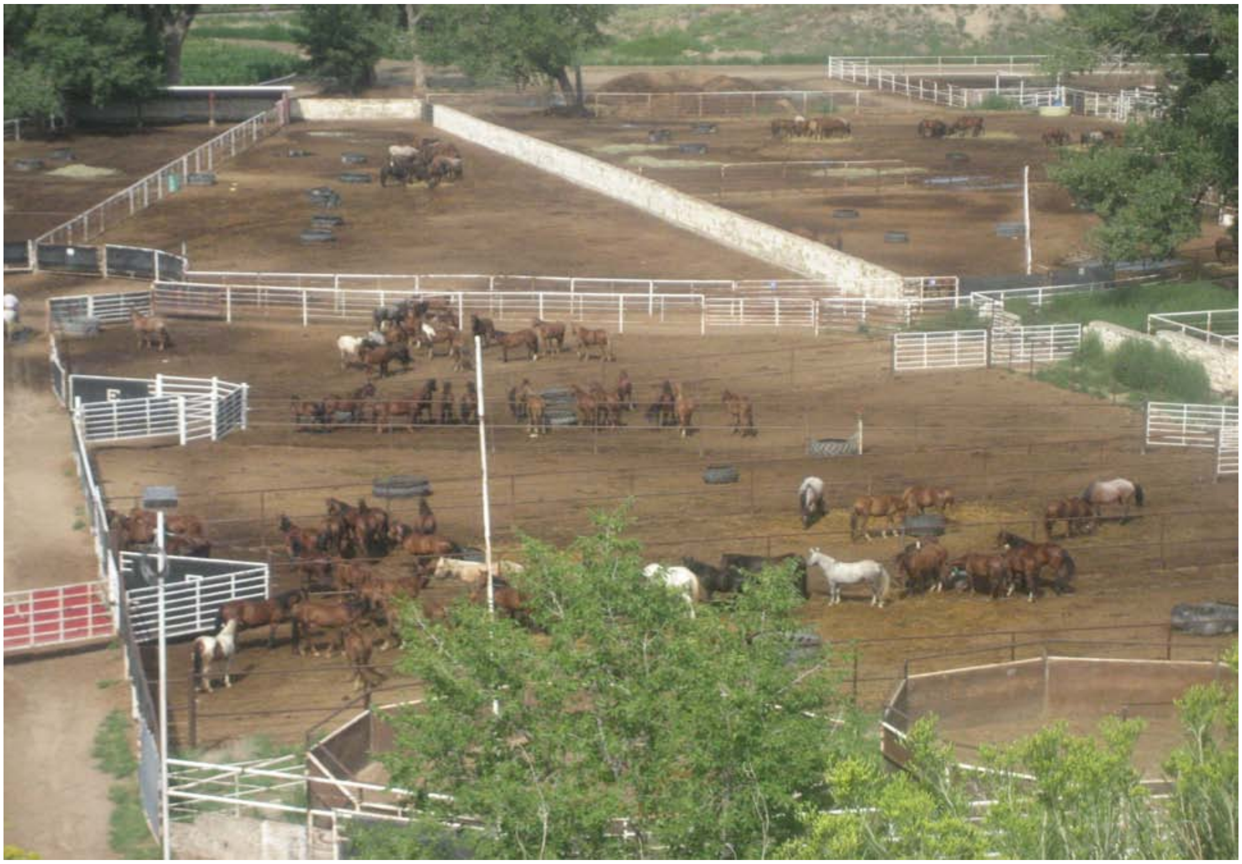

Photo 5.3.4 Road View of the CCI Tilapia Farm and Goat Nursery (immediate left)

Photo 5.3.5 Close Up Photo of the CCI Tilapia Barns (bottom)

Photo 5.3.6 Tilapia Breeding Tank
Two large, fiberglass cisterns serve as biofilters to cultivate tilapia, which are held in the rectangular holding tank. The plastic media creates surface area for bacteria growth, and the bacteria helps to maintain water balance for growing the tilapia. Once the tilapia are of a viable size, they are transferred to a larger fish run located within the same building.

Additional contact information:

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5.4 Christensen Farms Midwest LLC (Formerly Known as Colorado Pork, LLC). When Minnesota-based Christensen Farms LLC purchased the Colorado Pork LLC operation in 2006, they inherited the complete-mix digester installed by RCM International in 1999. The EPA AgStar database currently lists the operational status of the Lamar, Colorado AD unit as being "shut down". A July 22 interview with Christensen Farms Environmental Manager Adam Barka revealed that the unit has been "operating consistently" since a new cover was installed in fall 2008. However, the operation now flares off the biogas, rather than converting the energy to electricity.

The Christensen Farms AD has had chronic operational problems, and has not been shown to be an economically viable investment. Considered an early model of a modern era AD, the project installation and maintenance has been reportedly been subsidized by numerous federal grants during the past decade. The project has also served as a pilot study for the Environmental Protection Agency. A one-year technical study was conducted by Dr. John H. Martin beginning in April 2000. The final report submitted to the EPA in 2003. Dr. Martin's technical report also included an economic analysis, which noted an *annual loss* in farm income at $931/year or $0.19 per unit of sow capacity per year. The rate of return with internal financing, which was the method of financing the CP system, was slightly less than seven percent. This was calculated as follows:

- Interest rate of 7% over 20 years for borrowed capital.
- Annual cost of the capital invested in the CP anaerobic digestion system is $34,736 per year.
- Annual gross and net revenues of $39,264and $33,805, respectively.
- Return on $368,000 capital investment of 10.9 years (ignoring time value of money).
- Annual principal and interest payments of $34,736 per year.
- 342,414 kWh of electricity generated.
- The values were based upon the following assumptions:
    - Seven percent interest rate.
    - Assumed revenues of biogas derived electricity generated and utilized onsite at $22,907/year at a rate of $.07/kWh.
    - Assumption of an average $5,459 per year for operation and maintenance.

Unfortunately, the negative farm income has been even larger than estimated in Martin's report, due to long periods of generator down-time. During Martin's study, the engine-generator set was out of service for 32 days and for extended periods of time. However, the generator down-time was treated as an anomaly, and Dr. Martin revised his revenue values upwards slightly to assume improved efficiency and operation. According Christensen Farms, the downtime during the feasibility study was an unfortunate foreshadowing of problems yet to come, resulting in even greater losses to farm income than estimated in Martin's report.

Mr. Barka was unable to provide specific cost or down time information prior to the purchase by his company in 2006. However, he described the system as "problematic" from the time his company purchased the unit until the cover was replaced in fall 2008. He attributes the operational problems to "design flaws" such as the pairing of a square holding tank with a complete mix digester. He also attributes the operational difficulties to an inadequate volume of feedstock. The unit was built in anticipation of expanded farm capacity and manure at three times the size of the 5,000 sow-farrow-to-wean-operation. The relatively low amount of feedstock affects the holding time of the waste, the composition of the biogas emitted, and the system function. Furthermore, Mr. Barka reiterated that the corrosiveness of biogas on electrical generators resulted in a "vicious cycle" of generator repair costs, while electricity costs continued during engine shut-down time.

Mr. Barka stated that the primary motivation for maintaining the AD system was to remain within compliance with state air emissions regulation standards. In 2007-2008, the electrical generator was converted from biogas to natural gas. This involved considerable expense, although data were not available for costs incurred. Waste heat is used to maintain the digester and the farm flares off the remainder of the gas. The company is not interested in returning to electrical generation, but acknowledges benefits to odor control and future potential for energy independence.

Up to this point, Christensen Farms has been focused on stabilizing the AD system function. Mr. Barka provided the following insights into cost containment and areas of future revenue generation:

- In fall 2008, approximately $180,000 was spent to replace the system's cover.
- The site employs a maintenance worker (at approximately $15-$20/hr.) who spends approximately 20-25 hours per week to ensure accurate digester operation.
- The company qualifies for and eventually intends to obtain carbon credits.
- The company is not currently using the effluent, but is considering this to be a future opportunity.

Additional contact information:
Christensen Farms Midwest, LLC: 23971 County Road 10 Sleepy Eye, MN 56085
Main point of contact: Mr. Adam Barka (Environmental Resource Manager—MN):
507-794-5310 ABarka@christensenfarms.com
Mr. Dave Nord, Operations Maintenance Supervisor
Lamar, Colorado contact: Mr. Kritch Stokey, Maintenance Specialist: 719-940-0087

5.5 City of Greeley. Bruce Biggi, the Economic Development Manager for the City of Greeley, is directing a large-scale effort to develop a "Greeley Clean Energy Park" on land within the Western Sugar Tax Increment Financing District. Biggi requested—and received—NEED grant funds to conduct a Phase 1 engineering and economic feasibility analysis for a co-digestion project. The City of Greeley contracted with the technology provider Symbios and Stewart Environmental Consultants to conduct the first phase of the study. The economic feasibility study began April 1 and the first draft of the report is expected by September 29. The final report will be due to the City of Greeley and GEO by October 30.

Mr. Biggi (City of Greeley), Mr. Justin Bzdek (Symbios), Mr. Rick Jones (Symbios), and Mr. Forbes Guthrie (Stewart Environmental Consultants) attended an in-person meeting in the Symbois Ft. Collins office. Other discussions with Mr. Biggi pertaining to the project took place over the phone and email. Since the City of Greeley study coincides in parallel with the Economic Feasibility Project, data sharing was a difficult task. However, the meeting revealed that information from both projects will contribute to a synergy of knowledge that could serve to move forward AD projects by the end of the year. Those in attendance agreed to provide support and data sharing to as much extent as possible.

The group identified that the insolvency of New Frontier Bank has made it difficult for local industries and agricultural producers to secure capital. Those in attendance also agreed that state policy changes could be made in the areas of permitting, net metering, and carbon monetization programs to ignite interest in co-digestion projects.

5.6 New Belgium Brewery: New Belgium Brewery (NBB) is a well-known Ft. Collins microbrewery that has branded itself as a leader in sustainable operational practices. NBB has used AD technology since 2002 to pre-treat left over wastewater from its beer production processing. The company replaced its original AD unit with a larger capacity unit in 2006, to accommodate production growth and increased demand for its products. The company is now in the midst of a feasibility study to expand its use of AD technology to accommodate high solids waste, including up to 700,000 cubic meters of spent grain. NBB is involved in several alternative energy initiatives, including wind and solar energy. A recent NBB news release (Simpson, 2009) states that the manufacturer is able to produce, "up to 15% of its electrical needs by capturing methane from its process water treatment plant to fire a co-generation engine which produces heat and electricity on site."

Sustainability Director Jenn Orgolini and Brandon Weaver, Head Treatment Plant Technician, met in person to discuss the context of their previous and current AD projects. The decision to install an AD unit was made when the company was faced with paying the City of Fort Collins upwards of $4-$5 million in plant investment fees to increase the City's infrastructure capacity to process NBB's waste water. The company also reduced their wastewater surcharge fee approximately $15,000/month for the 225,000 gallons of water processed each day.

NBB estimates that it saved $6300 in electricity costs each month from January 2009 through April 2009 with its 290 kW digester. Orgolini and Weaver state that the company optimizes their biogas storage capacity to run the AD unit at peak demand times, effectively reducing 10.68% of the facility's overall energy, 23% of their peak energy demand and 30-40% of their energy bill. Energy prices paid by NBB (Intermountain CHP Center, 2009) are as follows:

- Coincident peak demand rate (when Platter River Power Authority hits system-wide peak demand) is $13.3722/kW.
- Fixed demand charges are $4.399 per kW for the first 750 kW and $3.012 thereafter.
- Energy use rate is $0.03/kW during non-demand times.

Weaver explains that the unit is run in two 4-hour blocks (a morning block and a late afternoon block) to optimize biogas storage during peak times. Maintenance is conducted during times of planned shut-down. Roughly two extra staff people are required to maintain the system. NBB currently does not qualify for carbon credits. Orgolini states that even with the energy cost savings, the $13 million upfront capital investment (including upgrades) "breaks about even". However, much of the company's philosophy and professional reputation has been built on the concept of sustainability. She believes that the AD system contributes to this theme, which been responsibility, in part, for the increasing demand for their products.

5.7 Wyoming Premium Farm, LLC (Wyoming). Wyoming Premium Farms is a 6,000 acre swine operation located in Wheatland, Wyoming. The operation is primarily owned by Japanese investors. Mr. Doug Derouchey, the operations manager, is the minority business owner. There are approximately 5,000 sows and 18,000 other swine in various stages of development, ranging from nursery to finishing. The operation owns two complete mix AD units that service four separately located barns. Approximately 20,000 gallons of waste are generated from the four collective barns. The AD units run 24 hours per day, seven days per week. AD #1, installed in 2003 at the sow barn for $1 million, presents 80kW capacity. AD#2, with 160kW capacity, was installed in 2004 to accommodate the other swine. The operation has a methane gas line tap, but the infrastructure is not feasible to support a gas line. Unused gas is flared.

In contrast to most projects, the Wyoming Premium Farms digesters were purchased in cash and received no government financial support. This is an important principle for Mr. Derouchey, who suggested the installation of the digesters to the majority owners. Mr. Derouchey believes that, "These are probably the only two digesters in the nation that were built with not one government dollar." Derouchey is forthright that the main purpose for the installation of the AD units was to mitigate costs stemming from nuisance lawsuits, and that the projects would otherwise not be economically viable. He attributes the poor economic returns to periods of long shut down, high maintenance costs due to the corrosiveness of the biogas, and low supply prices for selling electricity to the grid.

Mr. Derouchey was interviewed during two telephone calls and a July 22, 2009 site visit. He is accustomed to providing tours to visitors who have an interest in learning more about the digesters. Mr. Derouchey allowed photos to be taken of one of the digester units and he was willing to share some financial information, which has been integrated into the sensitivity analysis. Photographs of the operation are presented below, and electronic copies of the photos are available upon request.

Photo 5.7.1 Electrical generator at Wyoming Premium Farms. Photo reflects the generator for AD Unit #2, an 80kWH unit installed in 2003. Generator is contained within a storage facility located next to the complete mix digester. Mr. Doug Derouchey, operations manager and minority owner, is adjusting the system controls in the left hand side of the screen

Close up views of the generator's digital read-out screen (seen on left side of Photo 5.1) and pipelines are presented on the next page.

Photo 5.7.2 Close-up of generator controls (at right)

Photo 5.7.3 Inset of digital meter (below)

Photo 5.7.4 Water and gas lines in storage shed (below left)

Photo 5.7.5 Gas line located outside of shed (below right)

Photo 5.7.6. AD Unit #2, view from the south, looking north. The blue tower is an inactive holding tank. (at right)

Photo 5.7.7 AD Unit #2, view from the east, facing west. (below)

Photo 5.7.8 Influent/effluent mechanism (at right)

Photo 5.7.9 "Bubbling" indicates "good bugs" (inset)

Photo 5.7.10 Effluent water and electricity used to operate nearby irrigation unit (below)

Photo 5.7.11 Wyoming Premium Farms swine barn east of AD #2. Photo is taken while facing southeast. "Flare off" unit for biogas burn off is located on the right hand side of the photo. In the background is a school bus that has been adapted for use as a loading chute. Derouchey finds that the school bus design allows the vehicle to more effectively back in to the barns.

As follows is a summary of the financial data provided by Mr. Derouchey:

5.7.1 General Industry Information: Like the dairy industry, the swine industry is struggling. After years of running a profitable business, Mr. Derouchey reports that Wyoming Premium Farms operated $434,000 in the red last year and has lost $8 million over the past two years. He states that he does not believe that it is an appropriate time for agricultural producers to consider AD projects, because they are already struggling with shortages in cash, tightened credit markets, and short payment timeframes to keep accounts current. Operational costs of running an AD unit (such as maintenance costs) would only contribute to problems with tight cash flow.

5.7.2 Cost Information:

A. *Peak demand charges*: Mr. Derouchey reports that at least one time/month, the generator is forced to shut down during peak demand. Even when it is down for as short as 15 minutes during peak demand, Derouchey estimates that the operation is forced to pay $1,500-$3,000 in monthly charges to Wheatland Rural Electric.

B. *Annual maintenance costs:* Mr. Derouchey estimates that he pays approximately $20,000 per year for maintenance. Included in these estimates are:

   - Replacement generator parts from RCM International.
   - Routine oil maintenance (which takes places approximately once every 10 days).
   - Engine maintenance and repair specialists (e.g. $60/hr. for a specialized engine operator trained in tractor maintenance and repair from Caterpillar). At one time, Wyoming Premium Farms needed to contract with AD repair specialists from Missouri for digester maintenance and repair, but this need has been reduced since local labor have accumulated more experience in this specialized work.

C. *Major engine repairs:* In addition to annual maintenance fees, Derouchey states that he has "overhauled" and conducted major repairs to both engines on two separate occasions during the past five years. This involved replacement of valves, pistons, etc. Direct costs were estimated at approximately $20,000 (approximately $5,000 per incident, with two incidents observed for each digester). In addition to this expense, the operation was forced to purchase electricity during the times of generator shut down.

D. *On-farm labor for routine maintenance:* Mr. Derouchey currently employs the equivalency of one full-time laborer to maintain the AD units. Although AD review is required seven days per week, the estimated time of dedicated labor necessary to run the digesters is approximately 40 hours a week. The farm pays workers $8.76/hr. as part of a government sponsored agricultural work program. Housing, included in the worker's compensation, is not calculated in this expense. Thus, costs for routine labor are $350 each week and $18,221 every year.

5.7.3 Revenue and Cost Offsets:

A. Legal fee mitigation: As previously stated, Derouchey reports that the farm's single most important consideration for purchasing an AD unit mitigation of nuisance lawsuits. He estimates that earlier this decade, Wyoming Premium Farms paid roughly $200,000 in legal costs to fight two nuisance lawsuits, where the plaintiffs were seeking a total of approximately $2 million in punitive damages. The digesters were built as part of this negotiated settlement agreement. The Wyoming Premium Farms case illustrates two interesting rural western issues. One is that agricultural operations are susceptible to legal action, even in areas that are not experiencing rapid population growth, like Wheatland, Wyoming. Second, the topography of high elevation land results in cross-winds, and odor problems may be more difficult to predict than the mere presence of a "downwind" housing development. Derouchey's anecdotal advice is to build an operation at a *lower elevation* than the neighbor, if at all possible, as elevation changes can cause cross winds that blow from east to west.

B. Cost offset of irrigation system: The company is able to offset electricity and water costs by using electricity and effluent water to power a 125 horse power motor irrigation system. The irrigation system pumps 200/gallons per minute of effluent water onto irrigated silage corn (used to feed the swine and beef cattle). Additional irrigation water is also used and pumped at a rate of 600 gallons from a well. Based upon operational costs from four irrigation units, Derouchey estimates that he saves roughly $4,500/month for the 4 months of irrigation season ($18,000 annually). The other four irrigators are not located close enough to the generator infrastructure to utilize the energy.

C. Cost offset for lighting/fans: Mr. Derouchey reports saving approximately $2,000-$3000 each year from using on-farm electricity for lighting and fans.

D. Net Metered Electricity: Mr. Derouchey supplies excess electricity to Tri-State at a rate of $0.02/kWh. He is unsure of the average volume that he sells to Tri-State each month.

E. *Fertilizer:* The solids separators enable Mr. Derouchey to uses the remaining solids as fertilizer for silage corn, which is used to offset feeding costs for the 900 head cow-calf operation. Corn is also occasionally fed to the swine during the finishing process. Derouchey estimates that the operation produces 750 acres of corn each year and that he saves $150/acre in fertilizer costs for an annual savings of $112,500.

F. Carbon credits: Mr. Derouchey reports that he has sold carbon credits through 2007, although has not reported the volume sold or the revenues collected. He believes that the operation was able to sell the credits at a price of roughly $5/tonne, close to the market peak of $7/tonne.

Additional contact information:

Wyoming Premium Farms: 912 North Wheatland Highway Wheatland, Wyoming

Main contact: Mr. Doug Derouchey, Operations Manager and Minority Owner

Phone: 307-322-2266

http://www.wpfllc.com/

6.0 Economic Analysis: Budgeting and Sensitivity Analysis.

6.1 Summary. This section presents an economic analysis of AD projects in Colorado. The economic analysis is comprised of an enterprise budget, a sensitivity analysis, and a summary/interpretation of findings.

In summary, there is potential for a positive rate of return on co-digestion projects in the state of Colorado. Values used in the enterprise budget reflect a 3.66% annual return on investment. However, in order to achieve a positive return on investment, several key assumptions must be met, including $5.50/tonne carbon credits and controlled production costs. At present, conditions required for a positive AD project return are not favorable. Furthermore, due to the very small number of AD projects in the region, variations in the data may be observed when more AD units have been installed. To address this, three budgetary conditions have been proposed:

- A baseline of "expected" economic conditions, showing a positive annual return on investment.
- A budget modeling an approximate 20% reduction in each of the variables (unless otherwise specified) and a negative annual return on investment of -30.78%.
- A budget modeling a 20% increase in each of the variables (unless otherwise specified) and a 46.45% return on investment.

The enterprise budget and the accompanying financial assumptions for each of the conditions are discussed in Section 6.2.

The sensitivity analysis measures the responsiveness of income to a 1% change in operational variables. In other words, the sensitivity analysis effectively accounts for price volatility and models how these price changes affect the viability of a project. Operational variables selected for the sensitivity analysis were identified through interviews with technology providers, agricultural operations managers, and academic and trade publications. In summary, operational income was most sensitive to changes in production costs. A 1% change in production costs resulted in a 14.54% change in income. Examples of production costs might include unplanned AD maintenance and increases in labor. Operational income was also sensitive to energy production. A 1% change in energy production capacity (which is a function of engine efficiency and energy prices) yielded an 11.14% change in operational income. The results of the sensitivity analysis are consistent with anecdotal reports from agricultural producers, who report that changes in costs and energy production have a significant impact on project returns. An in-depth discussion of the sensitivity analysis is presented in Section 6.3

It is important to note that the enterprise budget and sensitivity analysis specifically address economic feasibility of AD in Colorado. Although data are available from other projects across the country, the decision was made to use regional-specific data in order to account for Intermountain West policies and practices. For example, published reports reflecting electricity use charges ranging from $0.08-$.12/kWh in New York or Pennsylvania (Leuer, Hyde, and Richard, 2008) yield a different budget compared to the typical $0.03-$0.07kWh prices seen in Colorado. However, the models account for the effect on producer revenues, should prices rise to levels seen in the eastern United States.

It is also important to consider the effect of high legal costs on operation profitability. An imminent lawsuit resulting in more than $5.9 million in damages (including punitive damages or fines in one year) would overcome the maximum losses projected by the "worst case scenario" presented in the enterprise budget. In other words, preventing legal conflict justifies the net losses from an AD project. This finding is consistent with the anecdotal information presented by technology providers and agricultural operators. This finding may be particularly relevant to areas facing high population growth pressures, such as Weld County, where nuisance lawsuits are a realistic concern as urban-rural boundaries are increasingly blurred.

Models are based upon technical assumptions for co-digestion, as a consistent level of diverse feedstock is required to ensure engine efficiency. Interviews with technology providers and agricultural operation managers (as well as preliminary data analysis of the Aurora Organic Dairy) indicate AD systems for a Colorado single farm project are not economically viable at this time, unless there is a key cost savings from lawsuit mitigation. Ignoring operational differences such as feedstock availability and energy content (which would presumably yield lower "typical" results for agricultural producers), a return of 3.66% is too low of a return for agricultural producers to implement a capital investment (Hoag, 2009). Future improvements in technology to accommodate high solids manure may lead to solutions for overcoming these farm-level technical and economic issues.

6.2 Enterprise Budget. The enterprise budget is presented in Figure 6.1. The middle column reflects "expected" financial and operation conditions, which will generate an annual return equal to $700,205. Much of the data for the "expected condition" enterprise budget is drawn from a proposal submitted to Tri-State Energy in 2008 for a co-digestion project involving an AD system and an ethanol plant in Fort Morgan, Colorado. This financial information was supplied by Mr. Bill Williams, CEO of Altresco International, an energy solutions company based in Parker, Colorado. Mr. Williams name was provided by GEO as a reference. However, citing confidentiality reasons, Mr. Williams was only able to provide limited information about the data collection and basis for the values. According to Mr. Williams, the proposed project was not funded, in part, because of uncertainty in feedstock availability. It is likely that the project reflected a plug flow reactor, but Mr. Williams was not able to verify the technology proposed.

Figure 6.1 Enterprise Budget for Colorado Co-Digestion Project

			Economic and Production Conditions		
	Unit	**Amount**	**Poor**	**Expected**	**Favorable**
Revenue					
Sale of electrical power					
Energy and VOM Payment	kVA	68,657,404	$1,098,518	$4,394,074	$6,327,466
Capacity Payment	kW	94,069	$571,938	$893,656	$1,286,864
Sale or use of Carbon Credits	CO_2	22197	$186,459	$2,563,754	$7,831,102
Total			$1,856,915	$7,851,483	$15,445,432
Production Costs					
Utilities			$94,765	$78,971	$63,177
Feedstock Procurement			$1,246,836	$1,039,030	$831,224
Bio-mass waste licensing fee			$180,000	$150,000	$120,000
Waste Disposition Operating Cost			$146,400	$122,000	$97,600
Water utilization			$554,072	$461,727	$369,381
Compensation & Benefits			$410,400	$342,000	$273,600
Feedstock Management			$198,000	$165,000	$132,000
Operational Mgmt & Suprv.			$300,000	$250,000	$200,000
Maintenance and Upgrades			$480,000	$400,000	$320,000
General and Administrative					
Lease Agreement for Land			$100,000	$100,000	$100,000
Insurance (General Liability)			$50,000	$50,000	$50,000
Legal and Accounting			$20,000	$20,000	$20,000
Total			$3,780,473	$3,178,728	$2,576,982
Earnings Before Interest Taxes & Amortization			**-$1,923,558**	**$4,672,755**	**$12,868,450**
Interest			$1,037,350	$1,037,350	$1,037,350
Amortization			$263,368	$263,368	$263,368
Depreciation			$2,671,832	$2,671,832	$2,671,832
Taxable Income			-$5,896,108	$700,205	$8,895,899
Income Tax (40%)			$0	-$280,082	-$3,558,360
Producers Tax Credit ($0.019/kWH)			$0	$280,082	$3,558,360
Net Income			**-$5,896,108**	**$700,205**	**$8,895,899**

As previously stated, the net income for the expected economic condition is positive ($700,205). However, a review of published reports and interviews with agricultural producers and technology providers implied downward variability in production revenues (e.g. tipping fees, energy production, energy prices per kWh) and costs (e.g. maintenance fees, unexpected downtime). Based upon this collection of information, it was estimated that there could be as much as a 20% decrease from the "expected" condition. Variable costs were reduced by 20% approximately from the "expected" condition to reflect "poor" economic conditions. The 20% threshold is a general statement, as some variables were changed by more than 20%, as noted in the spreadsheet. The "poor" economic conditions result in a negative net income (-$5,896,108). For the sake of argument, a 20% possible increase from the "expected" profile (or a "favorable" economic condition) could yield a greater annual net income ($8,895,899). The 20% upper boundary threshold is also approximated, and values outside of the 20% range are appropriately noted. As follows is description of the assumptions built into the enterprise budget model:

6.2.1 Gross Revenue. Gross revenue can be further explained as follows:

Gross Revenue = Energy and VOM Payment + Capacity Repayment + Carbon Credit

(1) *Energy +VOM Payment* = Energy Produced *.064 (expected price per kWh)

(2) *Capacity Repayment* = Capacity Rate (assumed at 9.55) * Billing Capacity

Billing Capacity=Energy Produced/Hours of operation per month (average of 744)

(3) *Carbon Credit*=Methane produced*5.5 (carbon price per ton)*21 (gas conversion rate)

Methane produced=

[Energy produced per month/ Sum of energy produced] *

[Annual methane produced in metric tonnes]

6.2.2 Feedstock conversion to energy. Feedstock is converted to "energy produced". This is determined as follows:

(1) Volume of slurry (lbs./day) converts to lbs of solids: % solids in feedstock=8%.

(2) Conversion to methane produced: 5.6 ft.^{3}/lbs. of solids.

This is the estimated conversion rate of feedstock from lbs. of solids to gas

(3) Biogas produced=methane produced/molecular ratio (.7) of methane to biogas

(4) Energy produced in BTUs =biogas produced*Heat content (65) BTU/ft.[3]

6.2.3 Production Costs. Production costs for the "typical" scenario were taken directly from estimates provided by Mr. Williams. Because production costs reported by those interviewed were substantially lower, the total costs were reduced by 20% to reflect a scenario of "poor" economic conditions.

6.2.4 General and Administrative Costs. This information was provided directly by Mr. Williams. These values are not likely to vary across economic scenarios.

6.2.5 Interest, Amortization/Depreciation, Taxes. This data was also provided directly by Mr. Williams. Values are based upon fixed capital costs and are not expected to vary across economic conditions.

6.3 Sensitivity Analysis. While the enterprise budget estimates that a co-digestion AD project in the state of Colorado can be profitable, changes in only a few key variables can affect project profitability significantly. The sensitivity analysis models the change in operation income (essentially in either the positive or negative direction) when key operational variables change by 1%. A sensitivity analysis was performed on six operational variables. The variables included in the analysis were identified by the literature, technology providers, and agricultural producers as variables that affected revenues or were subject to frequent or rapid volatility. Results are demonstrated in Figure 6.2, and are discussed below. Estimated changes to operational variables in "typical", "poor", and "favorable" economic conditions are also presented in Figure 6.2. These sensitivity estimates are based on the entire set of indentified variables changing at once, as compared to only one variable changing at a time as described in the second column of figure 6.2. The poor and favorable economic conditions reflected an approximate 20% change in the expected conditions. The 20% value was estimated similarly to the enterprise budget, and reflected technology provider and project manager reports. Upper and lower bound values that are cited from the literature are appropriately referenced.

Production costs and energy production showed the greatest impact on net income. A 1% change in production costs will change net income by 14.54%. Examples of production costs are maintenance/repairs, and labor. A 1% change in energy production (a function of billing capacity and methane production) will change income by 11.14%. Generator downtime and inefficient feedstock conversion both affect energy production. The high degree of impact on net income shown by changes in production costs and changes in energy production is consistent with the anecdotal observation shared by producers and technology providers, and the values obtained provide validation to these reports.

Figure 6.2 Results of Sensitivity Analysis

	% Change in Income for 1% Change in Variable[a]	Economic and Production Conditions		
		Poor[b]	Expected[c]	Favorable[d]
Capacity Payment Rate	1.25%	$7.60	$9.50	$11.40
Energy/VOM Payment Rate	6.15%	$0.02[e]	$0.06	$0.08
CCX rate/ton	4%	$0.5[f]	$5.50	$14[g]
Water Cost	1.21%	$600.00	$600.00	25[h]
Energy Production	11.14%	54,925,923	68,657,404	82,388,885
(billing capacity)	NA	75255	94069	112883
(methane produced)	NA	17758	22197	26636
Production Costs	14.54%	$3,780,473	$3,178,727	$2,576,982
Net Income	**NA**	**-$5,896,108**	**$700,205**	**$8,895,899**
Annual Return on Investment[i]	NA	-30.78%	3.66%	46.45%

a- Based on expected values, except for the variable indicated.

b - Assumes a 20 percent change in the variable, in the direction of reducing income, unless otherwise indicated.

c - Values expected in Tri-State Digester Proposal.

d - Assumes a 20 percent change in the variable, in the direction of increasing income, unless otherwise indicated.

e - Based on values reported in personal interviews with operators.

f - Based on low prices posted by U.S. Chicago Climate Exchange in 2009.

g - Based on estimated willingness to pay by: Tol, Richard SJ. 2004. The marginal damage costs of carbon dioxide emissions: an assessment of the uncertainties. Energy Policy 33: 2064-2074.

h - Value for leasing agricultural water, personal communication with Dr. Chris Goemans, water economist at Colorado State University.

Other variables included in the sensitivity analysis, along with their respective changes on net income were: capacity payment (1.25%), water—measured in cost per acre-foot (1.21%), energy purchase payment from net metering (6.15%), and carbon credits per tonne (4.0%).

The cost per acre price of water provided in the "expected" condition ($600) appeared high by agricultural water standards ($25 to lease agricultural water), validated by Dr.

Christopher Goemens, Colorado State University water economist. However, parameters associated with the water price (municipal prices) were not available, and the price was not adjusted. Instead, the same price was applied to the "poor" economic scenario, and the typical agricultural per acre-foot water cost (25) was applied to the "good" condition. However, net income was not as sensitive to water costs or capacity payment, as other variables. Net income was more highly sensitive to changes in electricity pricing for net metering. The low value for the energy price was provided by Mr. Derouchey of Wyoming Premium Farms.

An interesting result is the affect of price changes per metric tonne of carbon credits on net income (4.0%). Anecdotal advice and published academic studies (Leuer, Hyde, and Richard, 2008) suggest that positive net income of an AD project often hinges on carbon credits. If net income were to show high sensitivity to carbon credit price changes, producers may show rapid reductions in profit, considering the rapid change in carbon credit prices from over $7/tonne in May 2008 to below $1/tonne in June 2009. However, the sensitivity analysis shows that there is a more substantial reduction in net income with an increase in costs or reduction in generator energy production. Therefore, an operation should focus its efforts on cost reduction and ensuring efficient operation of the AD unit, and less on the price of carbon.

It is worth noting that emerging research is showing that the environmental benefits provided by carbon credits considerably exceed the market value. Tol (2004) summarized the environmental literature for the non-market and environmental values from CO_2 reduction. Of the 28 studies he reviewed, the *median* value (50^{th} percentile) of estimated environmental benefits reflected a $14/tonne price. The mode (most common), mean, and 95^{th} percentile values were $2/tonne, $93/tonne, and $350/tonne, respectively. Tol concluded that the true environmental benefits of a tonne carbon likely were substantially lower than $50/tonne. Therefore, the median value was used to estimate the "good" economic condition in the sensitivity analysis.

Several policy implications can be drawn from the sensitivity analysis. First, given the volatility around certain variables, it can be concluded that a regional digester project in Colorado is a risky venture. In order to increase the likelihood of success in co-digestion projects (which have the potential to yield environmental benefits), the state may wish to subsidize the difference between "typical" prices and a more extreme, unfavorable prices. Second, in a related policy, the state may be able to facilitate discussions with energy companies to negotiate a more favorable rate for net metering, or reduction of energy costs for alternative energy projects. Third, the state may choose to pay the difference between "typical" carbon offset prices with values based on estimated true environmental cost of methane reduction.

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8.0 Appendices.

8.1 Technology Providers Interviewed (in alphabetical order)

Ag Professionals, LLC: Tom Haren (Executive Consultant)

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Office: 970-535-9318 Fax: 970-535-9854

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Email: tharen@agpros.com

Altresco International, LLC: Bill Williams (CEO)

12925 North Sierra Circle Parker, CO

Office: 303-841-7788 Fax: 303-632-2401 Mobile: 303-909-1960

Email: Bill.Williams@wbill.com

Website:http://www.wbill.com/index.html

Heartland Renewable Energy, LLC: George Howard (President/Managing Director)

2400 Trade Center Ave, Suite 201 Longmont, CO 80503

Office: 303-485-0600

Website: http://www.heartlandrenew.com/

High Plains Renewable Energy, LLC:

Dan Feilmeyer (CEO/President) and Paul Parungo (Vice President, Operations and Finance)

33801 WCR 19 Windsor, CO 80550

Phone: 970.219.3564 Fax: 970.674.1732

Dan Direct Phone: 970-686-0366

Email: info@hprenewable.com
Website: http://www.hprenewable.com/team/index.html

Microgy, Inc.: Mike Casper, Market Development Manager

P.O. Box 309 Kenosha, WI 53141

Office: 262-654-7577; Fax: 847-589-8557

Email: MCasper@microgy.com

Website: http://www.environmentalpower.com/companies/microgy/

RCM International (Angela McEliece, Grant and Feasibility Writer/Manager)

PO Box 4716 Berkeley, CA 94704

Office: 510-834-4568 Fax: 510-834-4529

Email: amceliece@rcmdigesters.com

Website: www.rcminternationalllc.com

Stewart Environmental Consultants (R. Forbes Guthrie, Director of Business Development)

3801 Automation Way, Suite 200 Fort Collins, CO 80525

Office: 970-226-5500 X224 Fax: 970-226-4946 Cell: 970-222-2792

Email: Forbes.Guthrie@stewartenv.com

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Sybios: Justin Bzdek (President) and Rick Jones (Vice President, Business Development)

1219 Brumal Court Fort Collins, CO 80525

Bzdek Cell: 970-222-9178 Jones Cell: 970-222-0452

Email: Justin@SymbiosTechnologies.com

Website: www.SymbiosTechnologies.com

8.2 Summary of Colorado AD Permitting Process

PERMITTING FEES ASSOCIATED WITH AN ANAEROBIC DIGESTER FACILITY

Colorado Department of Public Health and Environment

July 2009

Per Catherine Keske's e-mail request dated June 29, 2009, permitting information addresses the following three scenarios:

1) Animal operations (ag only)

2) Mixed stream (self-contained ag site or co-location on ag site)

3) Mixed stream with imported waste stream (where tipping fees are collected).

Solid Waste

Regulatory requirements related to solid waste are administered by the Solid Waste Unit of the Hazardous Materials and Waste Management Division (HMWMD).

Solid Waste has the following applicable fees:

1. $125/hr for review of technical documents. There are ceilings for documents/ plans depending on the type of submittal. In scenario 1 and 2 it appears that a certificate of designation (CD) would not be needed but "one's own waste" requirements would apply. The document review cap for "one's own waste is $35,000. For scenario #3, where importation of solid waste is occurring, a CD is required. The review cap for a CD is $35,000. There are statutory review times for a CD (30 day completeness and 150 day technical review = 180 total days) there are no time review deadlines for one's own waste, however, the Solid Waste Unit's goal is to follow the same time lines and process as a CD.

2. In addition to the review fee there is an annual operating fee of $1000 which would apply to all three scenarios.

Local fees may also be applicable to these scenarios.

Air Quality

Permitting requirements for the protection of air quality are administered by the department's Air Pollution Control Division (APCD).

The following permit fees are applicable to regulated sources of air pollution:

1. Air Pollutant Emissions Notice (APEN) Filing Fee of $152.90 per APEN - As part of the permit application, the applicant must submit an APEN for every non-exempt emission point. For example, if a facility has three APEN-required emission points, they would submit filing fees of 3 x $152.90 = $458.70.

2. In addition to the filing fees, a Permit Processing Fee of $76.45/hour applies. This fee is paid just prior to issuance of the permit. It is difficult to predict a number of hours for an anaerobic digester permit since the air division is not familiar with this type of source, but it might be somewhere in the range of 40 to 80 hours. The estimated length of time to complete the air quality permitting process is generally four to six months (if complete information is submitted).

3. Separate from the filing/permitting fees, APCD also charges an ongoing Annual Emission Fee of: $22.90/ton of criteria pollutant, and $152.90/ton of hazardous air pollutant

Water Quality

Permitting requirements for the protection of surface and groundwater in Colorado is administered by the Water Quality Control Division (WQCD).

Annual permits fees could include the following, depending on applicability:

(1) Individual Discharge Permit (fees based on flow)

Category 12 Manufacturing and other industry

Subcategory 1 Cooling water only $1,140

Subcategory 2 Process water from 0 up to 49,999 gallons per day $2,150

Subcategory 3 Process water from 50,000 up to 999,999 gallons per day $3,280

Subcategory 4 Process water from 1,000,000 up to 4,999,999 gallons per day $9,880

Subcategory 5 Process water from 5,000,000 up to 19,999,999 gallons per day $12,140

Subcategory 6 Process water 20,000,000 gallons per day or over $19,760

Subcategory 7 No discharge $1,480

(2) Stormwater permit (Required if more than one acre of land is disturbed.)

Construction $245

Industrial about $400

The estimated time to complete water quality permitting is at least 180 days, and more likely one year. Stormwater permits, however, can be obtained within 30 days.

Animal Feeding Operations

Requirements related to Colorado's concentrated animal feeding operations are administered by the Department of Public Health and Environment's Environmental

Agriculture Program. If an anaerobic digestion facility co-locates at a concentrated animal feeding operation (CAFO) or a housed commercial swine feeding operation (HCSFO) (Scenario 1), the fees listed below may apply -- dependent to the extent the two operations are interconnected (i.e., utilize the same impoundments, locate on the production area, etc.) The period of time for permit processing is 180 days dependent on completeness of the application, but could take up to one year.

- Animal Feeding Operation (AFO) - no fee
- Non-permitted Concentrated Animal Feeding Operation (CAFO) - $0.06/animal unit
- Permitted CAFO (general permit) - $0.09/animal unit + $750 base fee
- Permitted CAFO (individual permit) - $0.09/animal unit + $1,500 base fee
- Housed Commercial Swine Feeding Operation (HCSFO) - $0.26/animal for water permit (only option is individual permit); additional $0.07/animal for air permit.

An animal unit is defined as the corresponding number of animals that produce the manure and wastewater equivalent to one steer (i.e., slaughter & feed cattle - 1.0, mature dairy cattle - 1.43, swine over 55 pounds - 0.40, swine less than 55 pounds - 0.10, sheep or lambs - 0.10, horses - 2.0, laying hens 0.01).

Permit processing fees for amendments to existing CAFO and HCSFO permits are as follows:

1. Minor permit amendments – an amount equal to 25% of the annual fee for the permit being amended, not to exceed $2,810.
2. Major permit amendments – an amount equal to 55% of the annual fee for the permit being amended, not to exceed $5,950.

Contact: Phyllis I. Woodford, Manager
Office of Environmental Integration & Sustainability
Colorado Department of Public Health & Environment
4300 Cherry Creek Drive South
Denver, CO 80246-1530
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8.3 Overview *of the* California Environmental Review *and* Permit Approval Process

The California Environmental Quality Act (CEQA) was enacted in 1970 as a system of checks and balances for land-use development and management decisions in California.

Environmental review is characterized by an Environmental Impact Report (EIR). The EIR records the scope of the applicant's proposal and analyzes all its known environmental effects. Project information is used by state and local permitting agencies in their evaluation of the proposed project

In 1977, the California Legislature passed the **California Permit Streamlining Act** (PSA) and established the **Office of Permit Assistance** (OPA). The creation of both OPA and PSA sought to remedy a complicated and often unresponsive permitting processes. The Permit Streamlining Act addressed some of CEQA's shortcomings: namely, that it lacked a calendar by which applicants and the public could expect the prompt review of a given project. The PSA added time-lines and deadlines to expedite government review of proposals. While this did not guarantee the approval of projects or their favorable review, it did give applicants and the public an orderly, standardized process for filing reports and actions.

California's environmental review is rigorous by anyone's standards. In most cases it extends beyond federal statutes established under the National Environmental Policy Act (NEPA).

- **Cities and counties regulate land use by way of planning, zoning, and subdivision controls.** There are currently 58 counties and over 470 incorporated cities in California, each with the same authority for land use regulation. Local government authority is granted by State law. Cities and counties have legislative power to adopt local ordinances and rules consistent with state law.
- **State agencies regulate the private use of state land, resources and certain activities of statewide significance.** There are at least 21 state agencies which are or may be directly involved in the approval of development projects. The permitting authority of each state agency is established by statute, usually with additional administrative rules promulgated by the agency.
- **Federal agencies have permit authority over activities on federal lands and over certain resources** which have been the subject of congressional legislation: i.e., air and water quality, wildlife, and navigable waters. The U.S. Environmental Protection Agency generally oversees the federal agencies. In addition, the EPA regulates activities such as the disposal of toxic wastes and

the use of pesticides. The responsibility for implementing some federal regulatory programs, such as those for air and water quality and toxics management, has been delegated to specific state agencies.

The Development Permit Process

In California, the development permit process is coordinated with the environmental review process under CEQA. Every development project which is not exempt from CEQA must be analyzed by the lead agency to determine the potential environmental effects of the project. This analysis is required by state law. It must be completed within specified time periods which are concurrent with the time periods in which an agency is required to approve or deny the project.

Once the lead agency is identified, all other involved agencies, whether state or local, become responsible or trustee agencies. Responsible and trustee agencies *must* consider the environmental document prepared by the lead agency and *do not*, except in rare instances, prepare their own environmental documents. The procedure for issuing each particular development permit is governed by the particular law which establishes the permit authority and by the California Permit Streamlining Act.

Summary of the CEQA and Permit Application Process

There are three major phases in the development process as provided by CEQA and the PSA:

- ***The Pre-Application Phase,***
- ***The Application Phase, and***
- ***The Review Phase.***

I. Pre-Application Phase:

The Pre-Application Phase begins when the developerapplicant has completed the conceptual and preliminary design work for a project and is ready to prepare a project proposal. At this point, enough information should be available to describe project activities and to identify the project's proposed location. The primary objective of this phase is to identify the appropriate permitting agencies and to collect as much relevant background information possible.

Many proposals (projects) will require special studies either before or during the formal processing of the application. All state and local agencies are required to list the type of information and the criteria they will use in evaluating a project application. DeveloperApplicants may request preapplication conferences or "scoping" meetings with the permitting agencies to discuss how agencies' specific rules will apply to their proposed projects.

By the end of the preapplication phase, the developer-applicant should have a good understanding of the detailed project information required, a list of probable permitting agencies, and an indication of the degree of environmental analysis required by the agencies.

At this point, the applicant will learn which agency (if there will be more than one permitting agency) will be the "lead agency." The lead agency is the single agency responsible for determining the type of environmental analysis CEQA requires. In addition, the lead agency must prepare the environmental review document it calls for. The agency with the greatest authority over the project will usually assume the lead agency role. Criteria for determining the lead agency are provided in the CEQA Guidelines at Section 15051. In the event of a dispute over the lead agency status between or among agencies, the Office of Planning and Research may designate the lead. However, once the lead agency is identified, all other involved agencies, whether state or local, become responsible or trustee agencies.

II. The Application Phase:

The Application Phase begins with the filing of the necessary permit application forms along with a detailed project description. Supporting documents must also be filed, where CEQA requires, with the respective agencies. Unless otherwise specified, the sequence of filing applications is left up to the applicant. It must be noted, however, that the failure of some agencies to accept an application until certain other permit approvals have been granted does not in any way impact the time limits under which the agency must act.

During this phase, each receiving agency must review the submitted application to determine if the individual filing is complete. The lead agency must make its determination in writing within 30 days. Should the agency fail to make its determination within 30 days, the application will be deemed accepted as complete by operation of law. If the application is determined to be incomplete, the agency *must* specify the deficiencies and the manner in which the deficiencies may be corrected. The developerapplicant may then refile the corrected application. Upon refiling, the agency has another 30 days to review for completeness. If the application is again determined to be incomplete, the agency must provide a process for an appeal of the determination and reach a decision within 60 days. Further dispute may be adjudicated. This step is critical to the process. A permit may not be denied for failure to provide information not requested.

Once an application is accepted as complete, the lead agency has six months to approve or disapprove a project for which an Environmental Impact Report (EIR) has been certified. The time limit in all other cases is three months after a negative declaration is adopted or an exemption issued.

III. Review Phase:

The Review Process begins immediately with the completion of the specific application. In recognition of §65941 of Chapter 4.5 of the Permit Streamlining Act, the lead agency will simultaneously review the project under the applicable permit rules and conduct the necessary environmental analysis. Permit rules vary depending on the particular permit authority in question, but the process generally involves comparing the proposed project with existing statutes. The procedure usually results in a public hearing followed by a written decision by the agency or its designated officer. Typically, a project may be approved, denied, or approved subject to specified conditions.

The CEQA procedure involves a number of steps which produce an environmental document examining the lead agency's as well as the responsible and/or trustee agencies' permit decisions.

The first step in the CEQA process is to determine whether the proposed project is subject to CEQA. There are a number of statutory and categorical exemptions. If the proposal is not covered by CEQA, the lead agency may file a *Notice of Exemption*. If the project is covered by CEQA, the lead agency must prepare an *Initial Study* to determine whether the project may have a significant adverse impact on the environment. The initial study must be completed within 30 days after an application is accepted as complete.

If the Initial Study shows that the project will not have a significant effect on the environment, the lead agency must prepare and circulate a *Negative Declaration.* Where potential significant effects are shown, but the project is modified such that the effects are rendered insignificant, the lead agency must prepare and circulate a mitigated Negative Declaration. In either case, the Negative Declaration must be circulated for review for 30 days and must be ready for adoption by the lead agency within 105 days after a completed application is accepted.

If, on the other hand, the Initial Study shows that the project may have one or more significant effects, the lead agency must circulate a *Notice of Preparation (NOP)* in anticipation of preparing an environmental impact report (EIR) and must consult with responsible and trustee agencies as to the content of the environmental analysis. Responsible agencies must respond to the NOP within 30 days. If a responsible or trustee agency fails to respond, the lead agency may assume that the responsible agency has no response to make. Further, if a responsible agency fails to respond or responds incompletely, the responsible agency may not subsequently raise issues or objections regarding the adequacy of the environmental review.

At the close of this period, the lead agency must prepare and circulate a *Draft Environmental Impact Report (DEIR)*. All concerned agencies and the public may review the DEIR. All comments on the DEIR must be made within the 45 day review period.

At the close of the review and comment period, the lead agency must respond to the comments received. Comments from responsible or trustee agencies shall be limited to those project activities which are within the agency's area of expertise, are required to be carried out or approved by the agency, or will be subject to the exercise of powers by the agency.

The lead agency prepares and certifies a *Final Environmental Impact Report (FEIR)*. If the lead agency approves the project, it must find that each significant impact will be mitigated below the level of significance where feasible, and that overriding social or economic concerns merit the approval of the project in the face of unavoidable effects.

With the CEQA and permit review process completed, the lead agency must approve or deny the permit within 6 months of certifying the EIR or within 3 months of adopting the Negative Declaration and file a *Notice of Determination (NOD)*. Responsible agencies must then act within six months after the lead agency's action or, if the developerapplicant has not already filed an application with a responsible agency, within six months from the time the application is filed (except as modified under Health and Safety Code §25199.6).

Environmental documents for projects involving one or more state agencies or involving issues of areawide or statewide significance must be sent to the State Clearinghouse for distribution to interested state agencies. The State Clearinghouse will link the lead agency with the responsible state agencies.

Special Concerns in the CEQA/Permit Process

There are several key points that agencies, developer-applicants and the public must be aware of in order to avoid misunderstandings and delays:

- The time limits for completing the requirements of CEQA and acting on a permit are concurrent and not consecutive. The Permit Streamlining Act discourages a government agency from requiring a completed EIR before accepting a permit application.

- CEQA can help resolve public policy disputes relating to development projects. Technical issues that find their way into policy disputes, no matter how dependent on scientific considerations, are inherently value-laden. CEQA specifically addresses the potential for conflicting expert discussions and mandates that all sides of an issue are considered.
- Under the Permit Streamlining Act, if a public agency does not approve or deny a project within the statutory time limit, the project may be deemed approved. The proponent must give notice to invoke the Permit Streamlining Act.
- The Permit Streamlining Act time limits are not applicable to all permit applications. Time limits only apply to development projects as defined in the PSA. The Streamlining Act specifically excludes ministerial permits such as certain building permits. The time limits do not apply to legislative actions such as the adoption or amendment of zoning ordinances. The time limits do not operate where a federal law specifies a longer or shorter period for action and, *with* the consent of the developer-applicant, the lead agency may waive the time limit if a joint environmental document is being prepared with a federal permitting agency.
- Where a public agency (or series of agencies) will issue more than one permit for a project, the agency(ies) makes each approval separately, but must still act upon the entire project within the statutory time limit.
- All Permit Streamlining Act time limits are maximum. Public agencies should act in a shorter time whenever possible.
- Members of the public may challenge, in court, a wide variety of public agency action and inaction, but only if they first present those challenges to the agency itself within 30 to 180 days after the occurrence of the challenged action, depending upon whether an NOD was filed or not by the agency.

Assistance for Developer-Applicants

The permit and environmental review processes are complicated. There are often several agencies and many persons involved. Hundreds of laws and rules may apply to a particular project. Agencies are constantly revising their procedures and changing personnel. The Legislature and the Governor created the Office of Permit Assistance (OPA) within the Trade and Commerce Agency to help project applicants, localities and the public to understand CEQA and the permitting process. The primary mission of the Office of Permit Assistance is to provide assistance and information to parties interested in the permit process.

- A single point of contact for state agency permits is available at the Office of Permit Assistance. Any questions about the permit process will be answered promptly.
- All state or local permits required for any project can be identified. The Office can convene all state agencies at one time to identify and explain which permits are required for a project.
- Scoping meetings can be arranged through the Office. The Office convenes meetings of the environmental staff of state and local agencies who will be involved in the CEQA review of projects. These meetings provide developer-applicants and environmental consultants with a chance to discuss all environmental issues and concerns early in the process in order to avoid wasted effort and unwarranted surprises in the EIR process.
- The Office of Permit Assistance has authority to convene meetings to resolve questions or mediate disputes. When uncertainties or disagreements among agencies stall the permit process, the Office may be called upon to provide a forum for resolving the problem. Not every problem can be dealt with in this manner, but when appropriate, the process can be very useful.

The Office of Permit Assistance can be contacted by telephone at 916/322-4245 (ATSS 473-4245). Its FAX number is (916) 322-3524. The mailing address is 801 K Street, Suite 1700, Sacramento, CA 95814.

8.4 Utah Department of Environmental Quality Supplemental Documents

Notes from Utah DEQ meeting Feb8, 2007

Attendance: CFF & Smithfield, Warren Petersen attorneys, DEQ pollution prevention, DSHW, USU, DWQ (Paul K, EPH), energy policy coordinator from governor's office

Sonja Wallace convened meeting at request of Dianne Nielsen to brainstorm ideas to make the BioEnergy plant a viable concern. Attendees introduced themselves and briefly described their knowledge of the manure to methanol process.

Intro discussion from CFF (Jim Webb and Prince Dugba). Original concept was to build the plant to use waste products where there was a large amount of manure available. At the design time, biodiesel economics were good. Electrical generation was not. Currently, methanol economics are not so good. Plant product has to be trucked to Texas to a biodiesel plant.

Process basics: there are two 4 million gallon anaerobic digesters; methane gas is collected after residence time in the digester, pressurized, sent to a 7,500 gpd methanol conversion plant. To be functional, the plant needs 1.5 MMCFD methane to make 3- 4,000 gpd methanol. Currently, after heating the digesters, there is 0.4 MMCFD methane available. There is a loss of manure energy between the barns and introduction into the digester. Supplemental organic feedstocks (SOF) can improve the gas generation. Glycerin (a byproduct of biodiesel production) is the best SOF found so far. Glycerin used to be 0.20 cents per gallon, now over $1 per gallon and in high demand by other users.

CFF has 144,000 finisher animals to provide manure, more than enough. Outdated NRCS research numbers may have been used to design the collection system. Manure energy level at barns is about 80% of the NRCS values, is about 65% at introduction to digester. Several theories discussed as to why numbers are different: different hog feed used today than 20 years ago, barn flush system is old technology. USU maintains reusing the grey water is bad idea, more fresh water should be used for flushing (bacteria).

<u>6 Technical challenges identified by the process engineer</u> (Prince Dugba)

#1 loss of manure energy before arrival at digester. Manure input volume is too low. This is 90% of the challenge.

#2 hydraulic retention time (this is resolvable)

#3 Gas stripping. From the AD, methane gas goes to a Stretford system that strips the H_2S to clean the gas down to 10 ppm. Want 0 ppm, so then gas goes through an "iron system". The Stretford tower was purchased used, and the metal is breaking down. May need replacement.

#4 Gas then goes to a steam reformer process that makes synthesis gas. Steam reformer was bought off of the shelf and is powered by propane, not natural gas. It uses a huge amount of propane and is costly. Natural gas fuel source would be better but nearest trunk line connection is 6 miles away and would cost $900K to tap it. Powering on waste natural gas would be best option if enough supply were available.

#5 Synthesis gas goes to a "Fisher Trough", which converts synthesis gas to methanol. Will need to upgrade the F.T. in a couple of years.

#6 Getting methanol economically to the market

Summary, as-built plant is not functioning. Everything has been studied to figure out improvements. Some maintenance, improvement, or replacement costs are looming, economics are not there because of cost of moving and heating manure, getting methanol to market and SOFs to the digester. Plant could be for sale based on internal review and economics.

USU – Conly Hansen

Said he toll CFF a long time ago that this system would not work. He had a review paper soon to be released that said anaerobic digesters in the U.S. are failing, not making any money. He says new farms should use and IBR (induced blanket reactor) to capture gas at the barns rather than the manure. Says the pit flush systems that recycle the water, while they work, are old technology. Volatiles are lost in the flushing. Electrical generation is not a viable payout. Conly did not offer suggestions, just mostly railed at all the "free" work he did for Smithfield that was not compensated.

SOFs discussion of SOFs that may be available to Smithfield, including whey from ice cream plants like Bluebell in St. George that is currently land applied.

End of meeting with no consensus of better ideas or preferred alternatives. Economics is the number 1 factor, as technological challenges can be overcome if enough money thrown at the plant.

<u>Pre-meeting background DWQ's file review of Smithfield BioEnergy project status and timeline</u>

July 2003

Issued original construction and groundwater discharge permits specifically for a Collection System and Central Treatment Plant, including an anaerobic digester system for all finisher farms in the Skyline Complex (UGW0100012). This changed the original anaerobic lagoon collection system design somewhat. New collection basins (buffer basins) were built at centralized points on farms to collect manure. Conveyance pipelines were installed to take manure and wastewater to and from the central treatment plant.

The Central Treatment Plant consists of influent pipes, gravity thickeners, four anaerobic digesters, effluent equalization basins, and return pump stations. The underflow from the gravity thickeners is conveyed to the digesters for treatment and biogas production. The biogas is collected from the digesters and conveyed to the biomethanol conversion plant. Effluent from the treatment plant is diverted back to the primary lagoons on the farms.

Each new basin adds a level of environmental monitoring and compliance, as it represents a potential leak source.

The Smithfield BioEnergy plant is built in 2003-04.

December 2004

Circle Four proposes a pilot study to introduce food waste into the anaerobic digester (needs additional volatile organic solids). DWQ approves a 90-day trial period. DWQ concerns about additional sludge going into lagoons and diminishing overall capacity and storage volume.

During plant start-up, excess RO water is generated. DWQ approves emergency disposal onto ground in an unlined pit. Elevated TDS now showing up in monitoring wells in 2006.

May 2005

Permit UGW0100012 is modified to incorporate the introduction of supplemental organic feedstock (SOF) and update compliance levels. SOF is supposed to enhance biogas production in the digester system. Approved on-farm concentration of solids.

Adding leftover sludge from off site processes represents an added environmental risk, as the residual waste products that are not converted will eventually be sent to the primary lagoons with the wastewater.

December 2005

Permit UGW0100012 is modified to change groundwater monitoring frequency to semi-annual.

April 2006

DWQ denied a request to dump more wastewater into an unlined digester pit. We requested an alternative engineering solution.

May 2006

Permit UGW0100012 is modified to incorporate construction of a wastewater containment basin.

August 2006

DWQ approves use of glycerin derived from biodiesel production as a SOF in the digesters to enhance biogas production. Said to be totally digestible leaving no sludge residue. Bench tests indicate it to be an ideal additive to pig manure for anaerobic digesters.

Annual Administrative fees collected by DWQ

UGW010012	total acres <15	$ 2,100 per year BioEnergy plant collector system
UGW010002	total acres 254	$29,050 per year
UGW010008	total acres 88	$ 5,600 per year
UGW210005	total acres 95	$ 6,300 per year
		$43,050 total annual admin fee

Web Notes

The Smithfield Foods Utah Project: From Hog Manure to Biodiesel

A recent example of an animal-manure-to-methanol project is one proposed by Smithfield Foods in Utah. A subsidiary firm, Best Fuels LLC, announced an ambitious $20-million project that would convert the manure from 23 hog farms (with a total of 257,000 finisher pigs) first to biogas and then to methanol for biodiesel production (Figure C-1). The farms were all within a 5-mile radius and the impetus for the project was the difficulty of marketing electricity from biogas produced from the animal manure. As shown in Figure C-1, manure (about 40,000 tons dry matter/year) collected from swine houses is pumped to a central location, thickened by gravity to about 4.5% solids and digested in ground, heated (95 °F), in floating cover digesters. The facility would produce about 1.2 million ft$_3$/day of biogas.

Project of Best Fuels LLC/Smithfield Foods for Converting Hog Manure to Methanol

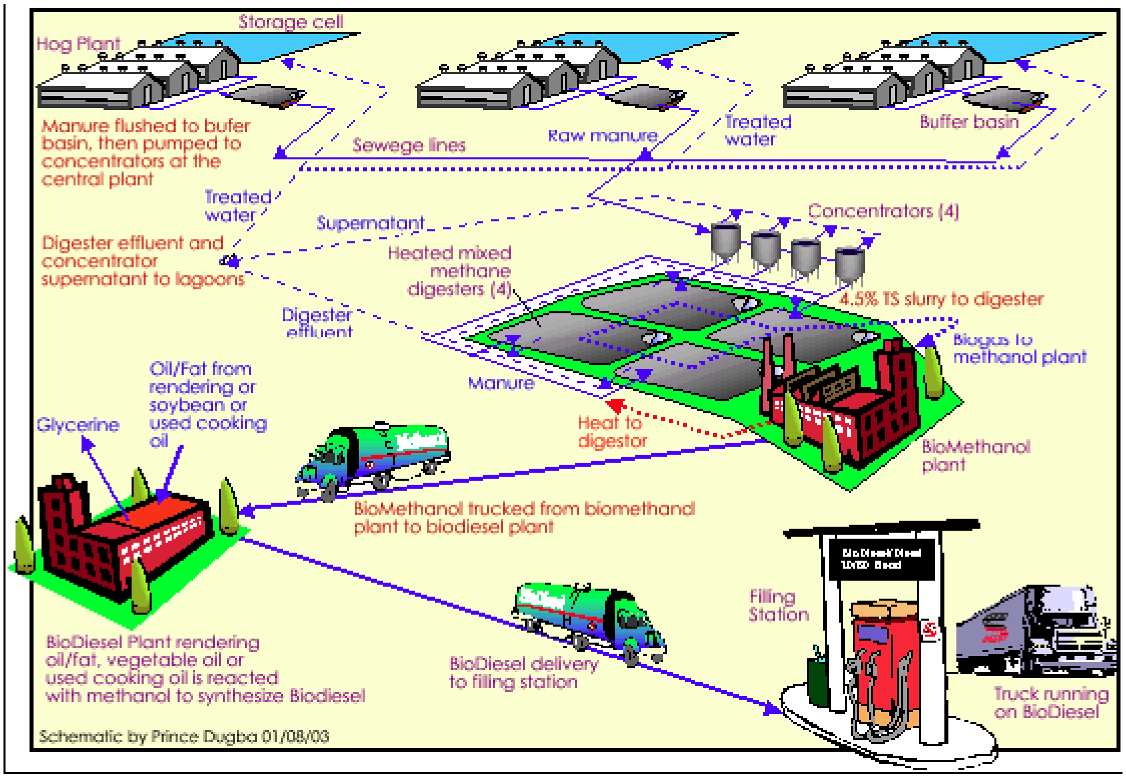
The biogas is next pumped to a central plant, where H_2S is removed with sodium hydroxide (NaOH). The gas is converted to methanol in a conventional steam-reforming/water-gas shift reaction followed by high-pressure catalytic methanol synthesis:

$CH_4 + H_2O \dashrightarrow CO + 3H_2$ and $CO + H_2O \dashrightarrow CO_2 + H_2$ gasification/shift reaction (1)

Methane + water Carbon dioxide + hydrogen

$CO + 2H_2 \dashrightarrow CH_3OH$ or $CO_2 + 3H_2 \dashrightarrow CH_3OH + H_2O$ methanol synthesis reactions (2)

The process at the Smithfield site is expected to yield 7,000 gallons of methanol per day. The methanol is used off-site for biodiesel production, expected to yield 40,000 gallons of biodiesel per day. The project literature states, "These processes should be considered industrial-scale processes, thus requiring a highly trained staff and high-tech equipment." However, after the initial much publicized announcement of the project no further information has become available. It is the opinion of the authors that if such an approach were even modestly economically attractive, it would have already been implemented under the much more favorable (from an engineering standpoint) opportunities made possible at stranded high-CO 2 natural gas wells. There the quality, quantity, pressure of the gas would much better justify their upgrading and conversion to methanol. It remains to be seen if this project actually moves forward.



Storage cell
Hog Plant
Manure flushed to bufer basin, then pumped to concentrators at the central plant
Sewege lines
Raw manure
Treated water
Buffer basin
Treated water
Supernatant
Concentrators (4)
Digester effluent and concentrator supernatant to lagoons
Heated mixed methane digesters (4)
4.5% TS slurry to digester
Digester effluent
Biogas to methanol plant
Oil/Fat from rendering or soybean or used cooking oil
Manure
Glycerine
Heat to digestor
BioMethanol plant
BioMethanol trucked from biomethanol plant to biodiesel plant
Filling Station
BioDiesel Plant rendering oil/fat, vegetable oil or used cooking oil is reacted with methanol to synthesize Biodiesel
BioDiesel delivery to filling station
Truck running on BioDiesel
Schematic by Prince Dugba 01/08/03

Status of Smithfield BioEnergy, Utah Plant June 13, 2006

Presently, the Smithfield BioEnergy Plant is operating as a self-heating facility. That is, biogas produced from the digesters is used to fire the boiler which produces steam to heat the manure and digesters. Enough biogas is presently produced to heat the digesters, but there is insufficient biogas being produced above the manure heating demand to fire the methanol production facility. The methanol production and refinement area is presently idle and has been since August 2005.

At present Smithfield BioEnergy is in the process of preparing a permit application that is a modification to the design originally permitted by the DEQ. This will be considered Phase 2 of the project, wherein we will collect manure from the additional 11 farms originally permitted. The first "phase" of the project included extending manure collection facilities to 12 of the 23 sites that were in the original permit. Presently manure is pumped into the plant from 12 farms consisting of 144,000 pig spaces.

We have learned several things from operation of our Phase 1 Operation. First, that we have a difficult time harvesting the available energy in the manure on an economical basis. Much of the energy in the manure is in dissolved form, does not fall out in the thickener underflow, and leaves the plant in the form of thickener overflow. We have attempted to run all of the manure that comes to the plant through the digesters, and see a significant biogas production increase. Unfortunately, operating in this mode, the digesters operated less efficiently, with only 40% VS destruction, due to reduced HRT to less than 10 days. In addition, there is a high amount of energy required to heat all of the water that comes to the plant with the liquid manure.

At present, our plan in phase 2 is to concentrate the manure at the farm level, truck this to the plant, and to also bring in supplemental organic feedstocks (SOF's) and to combine and introduce these organic feedstocks at the existing plant headworks.

The principal idea is to increase biogas production. All of the manure from the existing farms connected to the system would be ran through the digesters without thickener overflow and combined with trucked in concentrated manure and SOF's. Phase 2 would add an additional 4 digesters to the existing 2 phase 1 digesters, to increase overall HRT and digestion efficiency. In this manner biogas production can be increased to a level where the plant could operate within economic feasibility.

The technology has proven to be technically feasible, wherein methanol production from digested pig manure produced biogas can produce Methanol. In a 6 month production run, approximately 250,000 gallons of methanol was produced.

It is our intent to submit the permit application for Phase 2 construction to the DEQ by the end of this summer. Much of the design work is complete. We have been working on different technologies to concentrate the manure at the farm level and are having some success in that area to where we believe trucking in concentrated manure to the plant is viable. There are also modifications to the digester design to account for problems we have had with mixing and decanting of the digesters. We have gained significant experience over the first 2 years of operation, and are changing looking forward to the improvements Phase 2 construction will bring to the plant.

At present earthwork construction for the sludge containment and evaporation basin is near complete. This unit should be ready to be placed in service sometime around the end of August. Additionally, we are in the process of preparing a Notice of Intent on an Air Quality Permit to the Division of Air Quality. This should be submitted no later than June 20, 2006.

If you have more questions, please feel free to contact me. We would be delighted if the DEQ were to schedule a tour of our facility. A better understanding of how our facility operates can be gained on an on-site visit, where we can discuss our issues and challenges face to face. Let us know if you would like to schedule such a meeting.

Sincerely,

BJ Moore, General Manager (435) 386-8401

8.5 ActNeutral Project Financial Summary for Aurora Organic Dairy Project

Performance factors

Project life (years) 20
System biogas energy potential (kw) 315
Electricity generator conversion efficiency 35.0%
System electricity, usable output (kw) 101
Parasitic load, electricity (kW) 9
System electricity generation (kWh/a) 811,078
Heat parasitic load (kW) 47
System heat output, useable (kw) 108
System biogas output (kw) 0
System carbon offset output (ton/a) 0
Revenue Factors
Electricity value, grid cost to AOD ($/kWh) 0.0937
Heat sales value, grid cost to AOD ($/MMBtu) 19.406
OpEx Assumptions
O&M expenses ($/a) 80,000
G&A ($/a) 0
CapEx Assumptions
Digestor system ($) 300,000
Generation equipment ($) 300,000
Site preparation 400,000
Other ($) 131,440
Construction insurance ($) 8,800
Construction ($) 200,000
Total project cost ($) 1,340,240
System salvage value ($) 0
Leverage (% of EPC) 0.0%
Return on Investment
Project internal rate of return -12.9%
Project net present value (20 years @ 10%) -1,260,570