July 14, 2010

Subject: Transmittal to ISEA Council of the Biogas Resources Report

Dear Council Members:

The Board of Directors (Board) of the Idaho Strategic Energy Alliance (ISEA) recognizes and thanks the Biogas Resources Task Force for their development of this report. The Task Force is comprised of volunteer experts, including energy engineers, developers, private and academic researchers, regulators, and policy experts, who have worked together in the interest of Idaho citizens to suggest actions that will help develop this (biogas) important Idaho energy resource.

The primary objective of the biogas analysis and report is the identification of barriers and challenges to expanding the production of electricity using Idaho-based biogas resources, and policy and other actions that could reduce the barriers and speed deployment of these systems. The conclusions and recommended options are not intended to be exhaustive, but rather form a starting point for an informed dialogue regarding the way-forward in developing this Idaho energy resource.

It is the ISEA Board's responsibility to evaluate recommended options and to articulate to you and other Idaho policy leaders and lawmakers our opinion regarding whether the potential benefits and costs associated with the suggested options create a favorable opportunity for Idaho citizens given the available data. Our initial review comments are summarized in this transmittal. The Board believes that a complete assessment of individual reports cannot be made, however, until all of the Task Force reports and options have been evaluated, including considerations of Economic Development & Finance, Energy Transmission, and Communications. In this respect, both this report and the Board's comments should be viewed as "living documents" that will be updated as significant new information and/or perspectives develop.

Summary of Task Force Recommendations

The actions recommended in the Report, and the ISEA Board's assessment, include:

1. Establishing a statewide renewable energy portfolio standard or carbon emission cap. The Board's assessment was either to oppose or provide support conditioned on substantial modification/clarification. The concern is that while this option would possibly improve the economics of biogas projects (as well as other renewable energy developments), it could lead to inefficient investment by utilities, creating higher costs for all consumers that outweighed the benefits of biogas production.
2. Amend the state tax code to include all renewable energy production in the property tax exemption. This proposal also received mixed review. The recommendation was seen as generally positive; however, amending the code must ensure that the exemption is limited to that property primarily used for renewable energy production.
3. Reduce the threshold for tax rebates to qualifying equipment and machinery to below the current 25 kW level. While supportive of the recommendation, the Board urged the same caution as expressed above that tax code amendment be thoughtfully crafted.

4. Legislation should be enacted to authorize the designation of Renewable Energy Enterprise Zones (REEZ). The Board was fully supportive of this recommendation.
5. Enable grant programs that will support critical technology advancements. The recommendation was generally supported. However, the Board recommended that any grant program be appropriately sized to the potential for biogas development in Idaho.
6. Establish active outreach and education programs. The Board was fully supportive of this recommendation. It was recognized that this action can be tied to the above recommendation regarding technology enhancements.
7. Expanded / more focused collaboration between biogas stakeholders and Idaho universities to remove technological roadblocks and enhance economic performance of resource utilization. The Board fully supported this recommendation. This recommendation is also related to 5) and 6) above.
8. Incentivize / enhance industrial partnerships (e.g. between resource producers, technology suppliers, and users). The Board fully supports this recommendation.
9. Increase State assistance in capturing federal funds for technology deployment assistance. The Board fully supports this recommendation.
10. Encourage / incentivize a community (or cooperative) approach to digesters for small dairies. The Board fully supports this recommendation.

<u>Proposed Action Items</u>

In addition to these comments, the Board recommends the following State agencies as those responsible for evaluating and, if in agreement, implementing the recommended options. The Board requests that the Council have the following units of government evaluate and decide on the assigned recommended options:

- ***Office of Energy Resources***
  1. Evaluate statewide renewable energy portfolio standard and carbon emissions cap.
  2. Consider amending state tax code to include all renewable energy.
  3. Consider reducing the threshold for tax rebates to below the current 25 kW level.
  4. Develop legislation to authorize the designation of Renewable Energy Enterprise Zones (REEZ).
  8. Consider options to enhance industrial partnerships.
  9. Assess federal funding opportunities.

- ***Center for Advanced Energy Studies***
  5. Develop options / suggestions for expanded grant programs.
  6. Develop / implement related outreach and education programs.
  7. Enhance collaboration among Idaho universities to reduce technology gaps.

- ***Idaho Farm Bureau and Idaho Department of Environmental Quality***
  10. Develop / assess a “community” approach to digesters for small dairies.

The Board requests the Council have these organizations develop a plan for evaluation and, if appropriate, implementation of these recommended options, including a timeline, for Board review. The ISEA Board and Biogas Task Force are available to assist in this endeavor.

Again, the ISEA Board is pleased to commend the work of the Biogas Resources Task Force and is pleased to submit their report to Council members for review.

Steven E. Aumeier,

Chair, ISEA Board of Directors

Biogas Task Force Options: Pros and Cons

Recommendation	*Page*		*Explanation*
Establishing a statewide renewable energy portfolio standard or carbon emission cap	6,30	Pro:	*Will promote non-traditional revenue streams such as tradable Renewable Energy Credits (RECs) and carbon credits, causing the market to value these credits at a higher rate, improving returns on developer investment. Greater returns allow the developers to invest in smaller projects.*
		Con:	*While this would possibly help the economics of biogas projects, it could lead to inefficient investment by utuilities that would create higher costs for all consumers far in excess of the benefits of biogas production*
		Con:	*Could increase the cost without realizing benefits - look at lower carbon standards so DSM can compete with renewables.*
Amending the state tax code to include all renewable energy production in the property tax exemption	6,30	Pro:	*Would help off-set the cost associated with installing and operating anaerobic digesters*
		Pro:	All renewables should be treated equally
		Note:	*While the concept of amending the tax code is laudable, it must be done with care to ensure that the exemption is limited to that property that is primarily used for renewable energy production and not subject to abuse.*
Reduction the threshold for tax rebates to qualifying equipment and machinery to below the current 25 KW level	6,31	Pro:	*Would allow small dairies to develop anaerobic digesters and benefit from the economies of scale in joining together*
		Note:	*While the concept of amending the tax code is laudable, it must be done with care to ensure that the exemption is limited to that property that is primarily used for renewable energy production and not subject to abuse.*
Legislation should be enacted to authorize the designation of Renewable Energy Enterprise Zones (REEZ)	6,30	Pro:	*Would encourage the perpetuation of anaerobic digestion in Idaho - could spur a new industry in Idaho while managing waste and odor of dairies.*
Enable grant programs that will support the needed technology advancements,	6,30	Pro:	*Establish active outreach and education programs*
Establish active outreach and education programs	6,30	Pro:	*Would help the public understand the environmental benefits of anaerobic digestors, create interest in potential students to study this technology, provide community support, and may encourage a willingness to pay for higher renewable energy costs in order to benefit the environment.*

Biogas Task Force Options: Pros and Cons

Collaborate with Idaho universities	6,30	Pro:	*Enables them to share research and development and design appropriate curriculum; expertise will be needed to maintain digesters as well as improvements to current technology.*
Create industrial partnerships	6	Pro:	*Enables sharing of technology and potential development of new business models.*
The state should pursue all options for federal funding	6,30	Pro:	*Supports work to develop needed technology advancements.*
Encourage a community approach to digester for small dairies	5	Pro:	*Would allow small dairies to develop anaerobic digesters and benefit from the economies of scale in joining together*
		Pro:	*The role of the state should be to enable such approaches and to eliminate any barriers to their use. Policies that allow sharing of deductions and credits, also enhance the feasibility of such approaches.*

Biogas Generation and Use in Idaho: A Report by the Idaho Strategic Energy Alliance Biogas Task Force December 2009

Typical Mixed Flow Anaerobic Digester

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Executive Summary

The Biogas Task Force was charged with evaluating the potential, benefits, barriers, and options for utilizing biogas or biomethane production as a source of renewable energy in the State of Idaho.

Biogas (a mixture of methane and other trace constituents) is produced microbially from organic material. This may occur naturally, in which case technology is required to capture and utilize the biogas, or the process can be accomplished with an engineered anaerobic digester.

Current Situation

Three sources of biogas production were identified as viable resources in Idaho: biogas generation from landfills; biogas generation via anaerobic digestion of dairy waste; and biogas generation by anaerobic digestion of wastewater streams for industrial sources, primarily food processing plants.

There are currently only 2 operational dairy anaerobic digesters in Idaho and both are using the generated energy on site with little impact on Idaho energy use. Idaho has two landfill gas-to-energy sites currently in operation, one in Kootenai County and one in Ada County. The Kootenai County operation utilizes the energy directly and was placed in operation primarily for leachate evaporation, therefore no estimates of energy production are provided. The Ada County operation generates electricity for use and estimates a 3.2 MW capacity. Of the food and beverage industry candidates for anaerobic digestion in Idaho, only 8 facilities currently use anaerobic digestion to treat process wastewater which yields an annual total energy production value of 542 billion BTU. Four of those facilities utilize the biogas in boilers on-site and 4 of the facilities simply flare the waste gas in burners.

Potential

The greatest potential for biogas production in Idaho comes from dairy farm operations. Idaho is home to over 600,000 dairy animals. Approximately 70% of the animals and 126 of the largest dairies (those with over 1,000 animals) reside in the Magic Valley. It is estimated that the Magic Valley has the potential to generate 34,430,199,300 BTUs per day or 10,087,957 kWh per day from dairy waste (assumptions for this estimate are presented in the body of this report).

Idaho has two landfill gas-to-energy sites currently in operation. Approximately 28 other landfill sites have exhibited the potential to generate energy from landfill gas. The estimated amount of municipal solid waste generated per day in Idaho in 2006 was approximately 1,083,270 pounds. Using the EPA's "Method A" to calculate energy potential, assuming that the energy content of the landfill gas is 500 BTU/cf, and the heat rate of a reciprocating engine is 12,000 BTU/kWh, the gas flow can produce 188 kilowatts of electricity. The annual output of 188 kilowatts is approximately 1,482 Megawatts per year, assuming a 90% capacity factor. This electrical generation is enough to power approximately 120 homes and provides a reduction of 1,106 tons of carbon dioxide per year. Forty nine food and beverage facilities in Idaho were considered feasible candidates for anaerobic digestion and biogas use based on their chemical oxygen demand (COD) loads and wastewater flow (Appendix C). Of those 49 facilities, 8 currently use anaerobic digestion to treat process wastewater. This yields an annual total energy production

value of 542 billion BTU which is approximately 39% of the total biogas that could be generated from the 49 candidate facilities.

Benefits to Biogas Generation and Use

Biogas generation, capture and energy production depend entirely on the utilization of organic material. For this reason, viable options for generation of biogas have some potential, often large, for treatment or elimination of waste streams. Use of dairy waste specifically reduces or eliminates odor generation, and can substantially reduce nitrogen loading to the ground water. Anaerobic digestion of wastewater streams from food and beverage production facilities is already used as an efficient method of wastewater treatment. Capitalizing on the energy production benefits may encourage more facilities to employ this effective treatment option. With landfill biogas capture, the treatment of landfill waste is the source of methane, and capture of that methane, as with the other options, provides a significant reduction in greenhouse gas emissions.

Barriers and Challenges to Development

Uses for biogas production from dairies, landfills, and industrial wastewater include direct on site use through boilers or generators, conditioning the gas and providing pipeline quality natural gas through utilities, and electrical generation for grid use. A summary matrix comparing the relative risks and benefits of each alternative is presented in Appendix A, Table 2.

Digesters owned and operated by a single dairy for direct use have environmental and nutrient management benefits, little to no job impacts and a small impact on replacement of energy use with a renewable energy source. The largest obstacle to direct use is the high capital investment to build the digester and the operating costs. Currently dairy owners have little incentive to assume the risk. A community digester approach could reduce or eliminate the cost burden on any individual dairy as long as the ownership model was designed to financially benefit the developer who finances and/or operates the digester as well as the dairies who participate.

Capital costs, interconnect costs and costs to purchase and maintain generators (even for on-site electricity use) are large economic barriers to electricity generation from dairy waste digestion. In addition, reliability of gas quality and flow make selling the electricity difficult. Therefore individual dairies are not inclined to adopt this practice. A community digester approach may improve cost management issues; however, the interconnect costs and reliability issues remain. The costs associated with the technology needed to clean the biogas to pipeline quality biomethane to sell to gas companies is also an obstacle, although investment into this technology is increasing.

Direct use of digestion of food processing waste can be attractive to the food processor when the cost of natural gas or electricity that can be replaced with biomethane in boilers is high. However, job impacts and renewable energy replacement is minimal. Electricity generation from food processing waste digestion appears viable if co-digestion of multiple waste streams can be accomplished, especially if these other waste streams are easily accessible with minimal transportation costs and have reliable feedstock sources. The high cost of interconnection to the utilities is the largest barrier to electricity generation as with the other resources. Cleaning the food processing biogas produced into pipeline quality biomethane is problematic given the costs

of the cleaning and the difficulties associated and linking the geographically disperse operations to the pipeline infrastructure.

Direct use of landfill gas captured and burned on-site presents a high development cost and risk that may be prohibitive unless attractive contracts with the electric companies and incentives are available. However, the technical issues associated with specific landfill construction limitations prohibit many landfills from pursuing this option. Landfills that are already engaged in capturing and flaring biogas are more likely to be able to use the gas for electricity generation, although this use has similar interconnection issues. Public acceptance issues are also present.

Options for Development

Ten options that include different combinations of biogas production, use, and business models were evaluated against criteria (Appendix A, Table 2) that reflect the State's goals to: (1) ensure a secure, reliable, and stable energy system for the citizens and businesses of Idaho, (2) maintain Idaho's low-cost energy supply and ensure access to affordable energy for all Idahoans, (3) protect Idaho's public health, safety, and natural environment and conserve Idaho's natural resources, and (4) promote sustainable economic growth, job creation, and rural economic development.

Based on this evaluation, the Task Force concludes that at this time, full scale deployment of anaerobic digestion at landfills is probably not feasible, although with time landfills may be better positioned to employ these technologies. The food and beverage industry will continue to pursue wastewater processing through anaerobic digestion as the costs begin to decrease. The option with the most likelihood of success in the immediate future is anaerobic digestion of dairy waste. Of the options for operating anaerobic digesters on diaries, the most viable option is a community digester where the waste from several dairies is used to generate electricity that can be sold to the utility companies. As the technology needed to clean the biogas continues to improve and costs go down, the option of selling the biogas to the natural gas utilities will become more attractive.

It should be noted that compared to other potential renewable energy resources being evaluated by the Idaho Strategic Energy Alliance, the potential energy offset, economic return, and job creation by development of biogas is relatively small. This Task Force therefore recommends that strategies that will enable renewable energy development across resources should be given priority consideration. Digester use and biogas capture combined with other renewable energy generation technologies in a renewable energy zone approach would enable the state to realize the benefits of odor reduction and environmental protection combined with greater renewable energy production.

In the near term, legislative actions that will promote use of biogas for energy in Idaho include: implementing and complying with anticipated federal renewable energy portfolio standards or carbon emission caps; amending the state tax code to include all renewable energy production in the property tax exemption rather than just wind and geothermal; and reduction the threshold for tax rebates to qualifying equipment and machinery that produce energy below the current 25 KW level.

Longer term strategies that will promote biogas utilization include: working with granting agencies and federal agencies to enable grant programs that will support the needed technology advancements, especially for gas conditioning; establishing active outreach and education programs that encourage community support; and collaboration efforts with Idaho universities and industrial partnerships.

1 BIOGAS AND BIO-METHANE GENERATION- AN OVERVIEW

1.1 Anaerobic Digestion

Anaerobic digestion (AD) is the process of microbial conversion of organic residues into "biogas" in a reactor or digester. AD is widely used in Europe and development continues to improve on existing technologies. The most commonly utilized AD technologies use animal waste as a source of organic material. Municipal solid waste and food processing wastes may also serve as feedstocks for the AD process. Environmental benefits include the reduction of greenhouse gas emissions, odor control and reduced nutrient loading into ground water. AD is also valuable because it provides new markets for waste material.

The AD process coverts waste material to biogas via a consortium of hydrolytic, fermentative, acid forming and methane producing bacteria. The resulting products are carbon dioxide, methane, and various trace elements depending on the initial feed material. Maintaining the symbiotic activity of the complex mix of organisms is essential to the process, which must be oxygen free and is temperature and humidity dependent.

There are numerous types of digesters in operation around the world, including stirred tank reactors, up-flow anaerobic sludge blankets, slurry digesters, and batch digesters. Only three types are currently recognized by the USDA's Natural Resource Conservation Service: complete mix digesters, plug-flow digesters, and covered lagoons. Each has its advantages and disadvantages. The National Renewable Energy Laboratory published a casebook on methane recovery from animal manures that describes the pros and cons in detail.[1]

Complete mix digesters are usually cylindrical tanks of steel or concrete that are able to handle very large quantities of manure. Mixing and heating of the manure prior to pumping into the tank is generally required and mixing is maintained in the tank. The process may be mesophillic or thermophillic, therefore reducing the hydraulic residence time (HRT) to 10-20 days. Capital costs are generally high. Complete mix digesters are best suited to large farm operations and total solids (TS) in the waste feed stream between 3% and 10%.

Plug-flow digesters are trough style reactors in which the manure is fed into one end in "plugs" and the digested waste material "flows" out the other end. They are often below ground. The manure is held in a mixing pit prior to being fed into the reactor and the pit is often designed to hold one day's manure production. The methane generated is captured along the trough with an impermeable cover. Plug-flow digesters were designed primarily for cooler environments where heating is not practical and therefore operate at mesophillic temperatures. The HRT is usually 20-30 days, and digester operates best with TS of 11%-13%.

Covered lagoons are designed for farms where hydraulic flushing is used to collect the manure into large ponds or lagoons that are then covered with a floating, impermeable material to capture the biogas. They are generally simple to construct and operate and are not heated,

[1] NREL/SR-580-25145, September, 1998

thereby reducing capital and operating costs. Covered lagoons are best suited for TS less than 3% and have HRT of greater than 60 days once they reach steady state. However, lagoons may take as long as 1-2 years to reach steady state and are subject to wide variations in efficiency with seasonal changes in temperature. In addition, lagoons must be lined to protect the ground water from contamination and they are not suited for areas where the water table is high.

1.2 Energy from Biogas

The methane recovered from AD can be used in a variety of ways. Medium Btu gas can be generated by removing the condensate and particulates from the recovered methane, and transporting the gas through pipelines as fuel for boilers and burners to generate steam. An alternative is to use the gas at the farm where it is generated in an onsite boiler. With more robust cleaning of the methane to remove the carbon dioxide and impurities, high BTU gas (no less than 985 BTU) can be produced and introduced into existing natural gas pipelines for use. This requires significant compression that, combined with the gas cleaning, usually results in high cost to generate. By removing the condensate and particulate and compressing the methane, it can also be used to run engines to generate electricity. However, again this is generally expensive and engine running time is limited. Methane may also be used as an alternative feedstock for production of chemicals such as methanol. This requires removal of water vapor and carbon dioxide, compression under high pressure, reforming and catalytic conversion and it results in a loss of 67% of the available energy.

2 Biogas Potential in Idaho

2.1 Dairies

Idaho is home to nearly 700 dairy farm operations and over 600,000 dairy animals.[2] The potential for producing biogas from the manure generated on these operations is promising, although certain issues must be solved to maximize this potential.

Estimating the biogas generation potential of a diary is a nuanced process that factors in the conditions at the given site to determine the amount of "wet cow equivalents" at the site. A "wet cow equivalent" is an amount of collectible manure equivalent to the manure production of one wet (i.e. lactating) dairy cow in one day. The most important factors to calculating the number of wet cow equivalents on a potential site are type of housing/confinement, manure collection protocols, and herd size, age, and breed. The following two examples demonstrate the effects of these factors on the calculation:

1. One wet cow in an open lot is equal to 0.2 to 0.7 wet cow equivalents. The only manure that can be efficiently collected from an animal in an open lot is that which is deposited in the parlor and the feedlanes. The manure deposited on the ground in the lot is contaminated with sand and hard to collect mechanically.

[2] United Dairymen of Idaho, "Idaho Fast Facts," http://www.idahodairycouncil.com/generaldairyinfo.asp (Last updated Sept. 21, 2008).

2. One dry cow in a free stall is equal to 0.5 to 0.9 wet cow equivalents. Due to differences in the feeding of dry and wet cows, the manure output of dry cows is lower. In addition, dry cows are not housed in free stalls because the space is too valuable. Instead, dry cows are found outside in open lots, resulting in the problems with sand contamination discussed above. A similar, yet more severe effect occurs with heifers and calves.

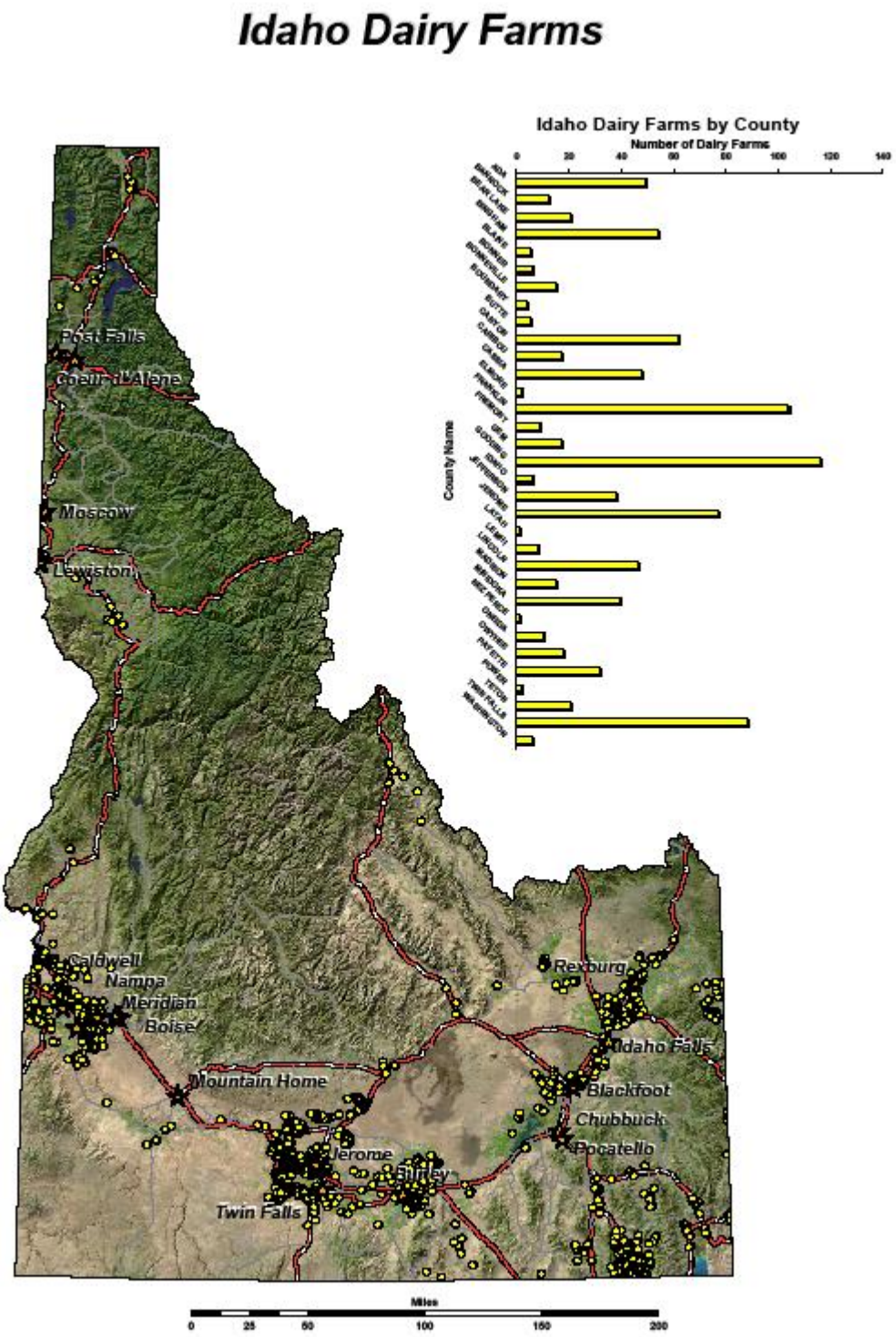
Digester providers, particularly those with projects on dairies with less than 6,000 wet cow equivalents, have found it difficult to generate sufficient returns on their investments. In general, a dairy usually requires at least 7,000-10,000 head in order to generate 6,000 wet cow manure equivalents. Less than fifty dairies in Idaho meet this criterion. In Idaho there are currently only two operational anaerobic digesters associated with dairies, one that is constructed but not currently in operation, and several in development.

The Magic Valley, which consists of the counties of Twin Falls, Jerome, Gooding, Cassia, Minidoka, and Lincoln, has the largest geographical concentration of mature dairy animals in Idaho (see Figure 1). Approximately 70% of the animals and 126 of the largest dairies (those with over 1000 animals) reside in the Magic Valley.[3] The Magic Valley's approximate 388,515 mature cows each produce approximately 120 pounds of manure per day. The amount of energy available per pound of manure varies depending on the type of feed and the collection methods used at the dairy, but can range from 2,000 to 5,000 BTUs. Assuming the Magic Valley manure contains 2,110 BTUs per pound, 98,371,998,000 BTUs are produced per day. Assuming that biogas generation from digesters has about a 35% efficiency rate, the Magic Valley has the potential to generate 34,430,199,300 BTUs per day or 10,087,957 kWh per day from dairy waste.

These numbers suggest that the Magic Valley could be an ideal location for a Renewable Energy Enterprise Zone ("REEZ"). Establishing a biogas REEZ in the Magic Valley has great potential to spur a new industry in Idaho while managing waste and odor. In addition, the Idaho Center for Livestock and Environmental Studies is anticipated to be located in the Magic Valley, which would be a real asset to a biogas REEZ in the area.

[3] Idaho Department. of Agriculture, Bureau of Dairying, *Waste Inspection—Animal Summary* (July 2006), *available at* http://www.agri.state.id.us/Categories/Animals/Dairy/Documents/animalSummaryJuly2006.pdf.

Figure 1: Dairy Farm Concentrations in Idaho



2.2 Landfills

Idaho has two landfill gas-to-energy sites currently in operation, one in Kootenai County and one in Ada County. The Kootenai County operation utilizes the energy directly and was placed in operation primarily for leachate evaporation. Therefore no estimates of energy production are provided. The Ada County operation generates electricity for use and estimates a 3.2 MW capacity. Approximately 28 other landfill sites have exhibited the potential to generate energy from landfill gas. Table 1 contains a list developed by the U.S. Environmental Protection Agency (EPA) of the landfill sites identified as having biogas generation potential.[4]

To be economically viable, a landfill gas-to-energy project requires very specific conditions. First, the landfill must have low plastic and construction waste because wood and plastic products decay very slowly. Second, either an average rain fall of greater then twenty-five inches is required, or the landfill must recycle the leachate (i.e. the liquid that drains or leaches from a landfill). Third, the viability of a landfill gas-to-energy project improves when landfills are over forty feet deep and have over one million tons of waste in place. Fourth, landfill gas production is maximized when the landfills are operating or have been recently closed. Landfills that are already flaring landfill gas are obviously viable candidates.

Ada County landfill met many of these criteria and therefore is able to generate enough methane to operate the generators on site. This situation, combined with acceptable agreements with local utilities for the generated electricity made this a viable energy operation.

2.2.1 Methane-to-energy calculation

Information about Idaho landfills is limited because neither the EPA nor the Idaho Department of Environmental Quality (DEQ) maintains a public database of current landfills. Therefore, the Biogas Task Force developed the "waste generated per capita" method to determine Idaho's potential landfill gas generation (see Appendix B, Landfill Gas Estimation Procedures). This method is suitable for information purposes only and should not be interpreted as actual generation potential.[5]

2.2.2 Methodology for determining waste generated per capita

According to the EPA, the per capita generation of municipal solid waste in 2006 was 0.74 pounds per day. The United States Census Bureau estimated that the population of Idaho in 2006 was 1,463,878. Using the formula $W_{D\ (\text{waste generated per day})} = P_{I\ (\text{population of Idaho})} \times W_{PC\ (\text{per capita waste generated})}$, the estimated amount of municipal solid waste generated per day in Idaho in 2006 was approximately 1,083,270 pounds.

[4] United States Environmental Protection Agency, *LMOP Database, available at* http://www.epa.gov/lmop/proj/index.html.

[5] United States Environmental Protection Agency, *Turning a Liability into an Asset: A Landfill Gas to Energy Project Development Handbook* (September 1996).

The potential to generate landfill gas can be estimated using the amount of municipal solid waste generated per day. The EPA's "Method A" equation[6] states,

Annual Landfill Gas Generation (cf) = 0.10 cf/lb x 2000 lb/ton x Waste-in-Place (tons)

To determine the cubic feet per day of landfill gas generated, the equation was modified to state,

Landfill Gas Generation per day (cf/d) = 0.10 cf/lb x Waste generated per day (lbs/day)

Using this formula, an approximate 1,083,270 pounds of waste generated per day can generate approximately 108,327 cubic feet of landfill gas per day. The amount of electricity that can be generated from 108,327 cubic feet of landfill gas is calculated using the formula,

Output (kW) = Landfill gas (cf/d) x Energy Content (BTU/cf) x 1/Heat Rate (BTU/kWh) x 1d/24 h

Assuming that the energy content of the landfill gas is 500 BTU/cf, and the heat rate of a reciprocating engine is 12,000 BTU/kWh, the gas flow can produce 188 kilowatts of electricity.

The annual output of 188 kilowatts is approximately 1,482 Megawatts per year, assuming a 90% capacity factor. This electrical generation is enough to power approximately 120 homes and provides a reduction of 1,106 tons of carbon dioxide per year. Using the EPA's Landfill Methane Outreach Program Emission Reduction and Energy Benefits Matrix,[7] the benefits of 188 kilowatts of electricity generated from landfill gas would be equivalent to:

- Removing emissions equivalent to 1,574 vehicles per year;
- Planting 2,243 acres of forest;
- Offsetting the use of 40 railcars of coal; or
- Averting electricity usage of 14,706 light bulbs.

[6] Method A is described in Appendix B.
[7] U.S. Environmental Protection Agency, *Landfill Methane Outreach Program*, http://www.epa.gov/lmop/index.htm

Table 1: Potential Landfills for Landfill Gas-to-Energy Projects in Idaho

Landfill ID No.*	Name	City	County	Waste In Place (tons)	Year Landfill Opened *	Landfill Closure Year	Landfill Owner Organization	Project Start Date	Utilization Type (Direct-Use vs. Electricity)	LFGE Project Type	MW Capacity
2067	Fighting Creek Farm Landfill	Coeur d' Alene	Kootenai	1,000,000	1993	2016	County of Kootenai	2/26/1999	Direct	Leachate Evaporation	
2165	Hidden Hollow Landfill	Boise	Ada		1972	2010	Ada County	7/31/2006	Electricity	Reciprocating Engine	3.2
1988	Fort Hall Mine Landfill	Pocatello	Bannock	2,000,000	1945	2008	Bannock County				
2178	Franklin County Sanitary Landfill	Preston	Franklin		1968	2007	Franklin County				
2166	Aitco, Inc. Non / Msw Site	Weippe	Clearwater				Aitco, Inc.				
2167	Bennet Road Landfill	Mountain Home	Elmore		1988	2070	Elmore County				
2168	Bingham County / Fielding / Goshen Landfill	Shelley	Bingham			2000	Bingham County				
2169	Bingham County Landfill-Ridge Road	Blackfoot	Bingham		1987	2002	Bingham County				
2170	Boise County Warm Springs Municipal Landfill	Idaho City	Boise				Garden Valley Non-Municipal Landfill				
2171	Bonneville County Landfill	Idaho Falls	Bonneville		1993		Bonneville County				
2172	Boundary County Landfill	Bonners Ferry	Boundary		1971	2022	Boundary County				
2173	Butte County Arco Sanitary Landfill	Arco	Butte			2022	Butte County				
2174	Butte County Howe Landfill	Howe	Butte				Butte County				
2175	Canyon County / Pickle Butte SLF	Nampa	Canyon			2060	Canyon County				
2176	Circular Butte Landfill	Terreton	Jefferson		1996						
2177	Council Landfill	Council	Adams				Adams County				
2179	Garden Valley Non-Municipal Landfill	Boise	Ada				Garden Valley Non-Municipal Landfill				
2180	Glenns Ferry Landfill	Glenns Ferry	Elmore		1958	2050	Elmore County				
2181	Hub Butte Landfill	Twin Falls	Twin Falls				Twin Falls County				
2182	Island Park Sanitary Landfill	Island Park	Fremont		1980		Fremont County				
2183	Jefferson County / Circular Butte	Mud Lake	Jefferson		1995		Jefferson County				
2184	Latah Sanitary Landfill	Moscow	Latah		1966		Latah Sanitation Inc				
2185	Lemhi County Landfill	Salmon	Lemhi		1980		Lemhi County				
2187	Montpelier Canyon Landfill	Montpelier	Bear Lake		1973	2042	Bear Lake County				
2188	North Rifle Range Landfill	Salmon	Lemhi		1993	2015	Lemhi County				
2189	Oneida County Sanitary Landfill	Molad City	Oneida		1981	2002	Southern Idaho Regional Solid Waste				
2190	Payette / Clay Peaks Landfill	Payette	Payette			2002	Payette County				
2191	South Idaho Regional SW District LF (Milner)	Burley	Cassia				Southern Idaho Regional Solid Waste				
2192	St. Anthonys Landfill	St Anthony	Fremont		1965		Fremont County				
2193	Teton County Landfill	Driggs	Teton		1980	2005	Teton County				

* Source: U.S. Environmental Protection Agency, LMOP Database, available at http://www.epa.gov/lmop/proj/index.html

2.3 Food Processing

In November 2008, the Biogas Task Force commissioned the Boise consulting firm HDR, Inc. to assess the current state of anaerobic digestion and potential for biogas production in the food and beverage industry in Idaho. A full report from HDR, Inc. is included with this report at Appendix C and summarized here.

Wastewater generated by the food and beverage processing industry is characterized by high chemical oxygen demand (COD) which must be removed for waste disposal. High COD wastewaters are favorable for anaerobic digestion and therefore anaerobic digestion is already practiced by several Idaho food processors. Facilities with low COD loads (<1000 pounds per day) are not candidates for anaerobic digestion.

Forty nine facilities in Idaho were considered feasible candidates for anaerobic digestion and biogas use based on COD loads and wastewater flow. Of those 49 facilities, 8 currently use anaerobic digestion to treat process wastewater. This yields an annual total energy production value of 542 billion BTU which is approximately 39% of the total biogas that could be generated from the 49 candidate facilities. Four of those facilities that generate biogas utilize it in boilers and the remaining 4 facilities flare the biogas using waste gas burners.

The 49 facilities that were considered candidates for biogas generation and utilization were evaluated using the following assumptions:

- Anaerobic digestion would remove 80% COD
- One pound COD removal produces 5.8 standard cubic feet of methane
- Average biogas methane content is 65%

With these assumptions, the total amount of biogas that could be generated by the food and beverage industry in Idaho is approximately 1.37 trillion BTU per year which is equivalent to the energy use for a population of about 3,880, or about 0.3% of Idaho's total energy use.

3 Uses of Biogas

3.1 On-site use of biogas through boilers and steam generation

Historically, biogas has been used primarily for on-site electrical power generation and/or heating water and buildings. Presently, it is most economically feasible to offset any propane use with biogas because of the higher cost of propane. The costs associated with retrofitting existing equipment or purchase new boilers that can burn the biogas must be

weighed against the savings incurred from not using local natural gas, propane, and electricity. The digesters typically produce considerably more biogas than can be used for local consumption and the excess is generally flared.

3.2 Condition the biogas to pipeline quality to sell to utilities

Several proven technologies are available to provide the necessary conditioning to produce pipeline quality biogas, although the technologies are very capital-intensive and notoriously expensive to operate and maintain. Given the generally low price of natural gas, a huge volume of conditioned gas is necessary to generate a return that would be considered attractive. One way to deal with this dilemma is to collect biogas from several digesters and pipe it all to one central cleaning facility. However, the costs associated with the transfer of the biogas tend to be prohibitive.

Conditioning biogas to pipeline quality requires compliance with Northwest Pipeline's (NP) standards because NP operates the pipelines used by the utility companies, and NP is required by the Federal Energy Regulatory Commission (FERC) to have "high quality" gas in its pipelines. Because biogas contains excess moisture, siloxanes, hydrogen sulfides, microbes, and other impurities, a gas conditioning system is needed to turn the impure biogas into clean, "high quality" pipeline quality gas.

NP's Gas Quality Tariff contains specifications for all gas delivered to its receipt points.[8] These specifications are as follows:

1. Hydrocarbon liquids and liquefiables: the hydrocarbon dew point of the gas delivered shall not exceed 15 degrees F at any pressure between 100 psia and 1000 psia as calculated from the gas composition and shall be free from hydrocarbons in the liquefied state.
2. Hydrogen Sulfide and Total Sulfur: The gas shall contain not more than one quarter grain of hydrogen sulfide per one hundred cubic feet and not more than five grains total sulfur per one hundred cubic feet.
3. Carbon Dioxide and Total Nonhydrocarbons: the gas shall contain not more than two percent by volume of carbon dioxide and shall contain not more than three percent by volume of combined nonhydrocarbon gases including, but not limited to, carbon dioxide, nitrogen and oxygen (except as otherwise provided).
4. Dust, Gums, etc.: The gas shall be commercially free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which interferes with the intended purpose of merchantability of the gas, or causes interference with the proper and safe operation of the lines, meters, regulators, or other appliances through which it may flow.
5. Heating Value: The total gross heating value of the gas deliverable hereunder shall not be less than 985 BTU.

[8] Northwest Pipeline, *Tariff*, General Terms and Conditions Section 3, *available at* http://www.northwest.williams.com/NWP_Portal/ (follow link to Tariff, Entire Tariff, General Terms and Conditions, Section 3.1—Quality) (last visited April 29, 2009).

6. Oxygen: The gas shall not contain in excess of two-tenths of one percent by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.
7. Temperature: The temperature of the gas at the point of delivery shall not exceed 120 degrees F.
8. Water: The gas delivered shall be free from liquid water and shall not contain more than seven pounds of water in vapor phase per million cubic feet.
9. Mercury: The gas shall be free from any detectable mercury.
10. Toxic or Hazardous Substance: The gas shall not contain any toxic or hazardous substance in concentrations which, in the normal use of the gas, may be hazardous to health, injurious to pipeline facilities, or be a limit to merchantability or be contrary to applicable government standards.
11. Bacteria: The gas, including any associated liquids, shall not contain any microbiological organism, active bacteria or bacterial agent capable of causing or contributing to: (i) injury to Transporter's pipelines, meters, regulators, or other facilities and appliances through which such gas flows or (ii) interference with the proper operation of the Transporter's facilities. Microbiological organisms include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (ACB). When bacteria or microbiological organisms are considered a possibility, Shipper(s) desiring to nominate such gas, upon Transporter's request, shall cause such gas to be tested for bacteria or bacterial agents utilizing the American Petroleum Institute test method API-RP38 or other acceptable test method as determined by both parties.

3.3 Generate electric power and deliver the power to the electric grid

Generating electrical power from organic based biogas requires a power plant complex composed of four main processes: (1) the collection, delivery, and conditioning of the methane gas; (2) the generation of electricity; (3) the generation and delivery of steam/hot water back to the biogas operation, and (4) the delivery of power to the electrical grid.

First, methane gas is collected from the anaerobic digester or landfill and pumped to the engine or turbine through low pressure gas pipelines. Because biogas contains excess moisture, siloxanes, hydrogen sulfides, microbes, and other impurities, a gas conditioning system is needed to clean the gas, although this system need not be as comprehensive as that needed to integrate the gas into the Northwest Pipeline system.

Second, electricity is generated from gas fired electrical generators. The generators are either reciprocating engines or combustion microturbines, and they can be packaged with electrical generators, stacks and catalyst systems for clean emissions, heat recovery generators, system controls, and switchgear. These generators tend to be only 30% efficient and produce waste heat, so a co-generation facility that uses the waste heat to heat water is used to maintain the temperature of the anaerobic digester.

Third, hot water must be circulated back to the digester to maintain the required temperature of 100 degrees F. The hot water can be produced conventionally (with gas or electric water heaters), or it can be generated from the waste heat produced by the generators. Finally, the power is delivered to the electrical grid so it can be sold to an interconnected utility. The facilities needed to interconnect to the grid include: transformers to step up the power to the grid voltage; system controls that synchronize to the grid; instrumentation to provide generation protection; and isolation breakers and switches. Some upgrades to the transmission network may be required before the utility will accept generation from a power plant.

To summarize, a typical power plant facility should integrate the following features: (1) a gas conditioning system to provide clean methane fuel to the engine; (2) a minimum of two identical engine units to allow for system redundancy and ease of maintenance (additional units can be added to increase methane output); (3) a back-up fuel connection to a medium pressure natural gas distribution line; (4) a heat recovery system to convert excess waste heat from the engine exhaust and engine body into hot water to be piped back to the biogas facility; and (5) connection to the local grid for the export of power to a utility or alternative energy purchaser.

The cost of interconnection should be considered when siting a generation facility. The facility should be located as close as possible to the intermediate substations where the line terminates or connects to other lines. Bonneville Power Administration, Idaho Power Company, and PacifiCorp are all transmission constrained. Small but reliable biogas power plants could be distributed in a sub-transmission system and potentially help avoid transmission and distribution investment and upgrades in areas where the systems are operating at maximum capacity. This “distributed generation” can improve the reliability and stability of the power supply while reducing the cost of electricity and lowering emissions of air pollutants.

The EPA and Idaho DEQ regulate air emissions and discharges to water bodies. Thus, any biogas power plant will be subject to permitting requirements for at least the following: containment of liquid waste byproduct; land application of liquid waste byproduct; flaring of methane gas; control of airborne particulate; H2S and other gas emissions from effluent ponds or storage tanks; storage and handling solid waste byproduct; storm water runoff control from liquid and solid waste containment area; air permit for controlled emissions; use of catalysts to control emissions; handling of liquids stripped from gas conditioning systems; siting and zoning requirements for power plant facilities; approvals from local utility for electrical interconnection; and approvals from local utility for natural gas interconnection. Obtaining the approvals and permits for a biogas power plant may take 6-12 months. The procedure involves securing the site, drafting a development plan, filing for the permits, and then navigating the approval process.

4 Biogas generation business models:

Anaerobic digestion biogas projects can be implemented under several potential business models. The simplest way to differentiate these models is to look at who owns the main asset—the digester. The four most typical ownership models are developer owned, investor owned, dairy owned, or utility owned.

4.1 BOOT

BOOT is an acronym for the "Build, Own, Operate, Transfer" agreement. This terminology is used to describe a business model where the developer builds and owns a digester on an independently owned source of feedstock, such as a dairy. Through the course of the BOOT agreement (typically 10-20 years), the developer is entitled to the revenue generated by the asset, with some concessions to the dairy operator for allowing the project on the dairy. The developer also is responsible for operating and maintaining the digester throughout the term of the BOOT agreement. At the end of the BOOT agreement, the developer can either transfer the asset to the dairy or some other entity at the market value of the asset.

The BOOT model is very efficient business model for several reasons. Because the developer owns the asset and is responsible for its upkeep and operation, the developer has an incentive to design and operate the asset as cost effectively as possible. On the other hand, when a provider simply builds and sells an asset to a customer, the provider has an incentive to "go cheap" initially, which may actually increase the costs to the customer over the lifecycle. Also, since the developer is responsible for the operations and maintenance, specialized professionals tend to do this work.

4.2 Investor owned digester

In an investor owned model, private investors either work with a developer or a dairy operator to build and operate a digester. The assets are owned by the investors but are generally either operated by the dairy or the developer, who keep the remaining returns after paying the investors. The investors are usually banks, venture capitalist firms, or other entities looking to "green up" their investment portfolio. The investor provides the initial capital outlay and may provide money to fund operations and maintenance in exchange for a guaranteed rate of return on their investment. This model can be less efficient than a BOOT agreement mainly because it introduces another hand into the revenue pot and the control of the digester is rarely local.

4.3 Dairy owned digesters

4.3.1 Independent operator owned

In this model the dairy either hires a digester provider for a design and manages the construction in-house, or purchases a turnkey system from a developer. The asset is on the dairy's books and the dairy either pays a management fee to a developer or operates the asset personally. In this case all of the revenues go to the dairy and the dairy covers all of the costs. A drawback to this model is that having the digester on the dairy's books affects the dairy's ability to procure capital for investment into its core business, milk. In addition, if the dairy operates the digester itself, it may hamper digester performance due to operation by inexperienced personnel.

4.3.2 Co-op owned

Diaries that have less than 10,000 head find it virtually impossible to make the investment necessary to be successful in implementing biogas-to-energy technology. Thus, it can be advantageous for numerous dairies to invest in an entity that will own one digester that all the dairies use. However, in addition to the drawbacks discussed above, this model could cause strife in the management of the digester-owning entity. An alternative to the dairy-owned co-op is the developer owned digester that operates on a co-op model. In this model, the developer owns and operates the digester as described above, but several dairies contribute manure and receive the benefits.

4.4 Utility owned digesters

This model is very similar to the investor owned except the investor is the local utility. The utility is then, in essence, selling the power to itself. Operational responsibility can be with the utility, a developer, or the dairy.

5 Barriers to Biogas Development

5.1 Barriers faced by dairies

The primary barrier facing the dairies is economic: the initial capital cost and the fact that fluctuating energy prices subject the dairy operators to uncertain revenue streams. It was estimated in 2004 that a biogas facility (excluding power plant) requires approximately $400/cow.[9] In 2006, the Idaho Department of Water Resources conducted energy production measurements at an operating biogas plant[10].

[9] Idaho Dairy Waste Conversion to Electricity- A Pilot Project Feasibility Study- Final Report, October, 2004. Prepared for USDA, Bonneville Power Administration, Idaho Dairymen's Association by Mountain View Power, Inc. Boise, Idaho.

[10] Energy Production Measurement at the Whitesides Biogas Plant, August 2006. Prepared for the State of Idaho, Department of Water Resources, Energy Division, by Intrepid Technology and Resources, Inc. Contract #DWR-CON00719.

They calculated that for production of electricity from anaerobic digesters with reciprocating engines the production from 100 ft^3 of biogas is as follows:

- 65 % methane concentration; 65 ft^3 of methane
- 1,000 Btu per ft^3 methane combusted; 65,000 Btu energy content
- 3,413 Btu per kWh (handbook conversion of units); 19 kWh energy content
- Efficiency of typical Cat reciprocating combustion engine 22%; 4.2 kWh net electrical production
- Sale price of electricity: $0.061 per kWh
- Electricity sales from 100 ft^3 of biogas: $0.26
- Total sales with carbon credits: $0.35

Alternatively, if the gas is conditioned for pipeline quality, standards must be met for heating value (greater than 985 Btu per ft^3), hydrogen sulfide (less than 0.25 grains per 100 ft^3), total sulfur (less than 20 grains per 100 ft^3), and moisture (less than 7 lb per million ft^3). The sales of pipeline gas from 100 ft^3 of biogas are as follows:

- 65% methane concentration; 65 ft^3 of methane
- 1,000 Btu per ft^3 methane combusted; 65,000 Btu energy content
- 20% biogas loss for process heating needs; 52,000 Btu remaining
- 90% efficiency in gas conditioning; 46,800 Btu remaining
- Sale price of natural gas: $8.00 per million Btu
- Gas sales from 100 ft^3 of biogas: $0.37
- Total sales with carbon credits: $0.46

Workforce issues are also present; unless the diaries contractually agree to have another entity operate and maintain the digesters, the diaries must hire and/or train qualified people to maintain the digesters. In addition, the dairies may be unwilling or unable to navigate the permitting and regulatory process for installing and maintaining a digester.

5.2 Barriers faced by landfills

Landfill gas-to-energy projects encounter many barriers, but this section is limited to those that are expected to significantly impact to developing a successful project.[11] In general, landfill gas-to-energy projects are typically constrained by lower benefit-to-expense ratios.

The high capital expenditure for an engine-generator set is the most common barrier for a landfill gas-to-energy project. Landfills are typically low revenue generating facilities. In low revenue generating facility, high risk projects such as landfill gas to energy are only

[11] PacifiCorp Internal Landfill Gas to Energy Study (2006).

developed when the benefits are high and the risks can be sufficiently mitigated. Additionally a landfill's access to funding is limited due to low energy production incentives, low energy output, and environmental benefits that are not considered in funding applications.

High development costs are mainly attributed to the initial verification of the landfill's potential. Drilling test wells can cost tens of thousands of dollars per well. The landfills must commit large sums of money to drill test wells that may turn into sunken assets if the gas production is not suitable for energy generation. If the result of the wells is positive, other economic barriers remain, such as determining the number of production wells to drill, establishing an efficient gathering field design, and negotiating interconnection and power purchase agreements.

If the landfill or developer decides to construct a project, the project is subject to a high risk of not meeting the "realized revenue generation" estimated during the project's feasibility study, which is required for the negotiation of the interconnection and power purchase agreements. The lower revenue generation may be from higher than expected maintenance costs or lower generation output. If the landfill cannot meet its power purchase agreement energy output, the landfill gas to energy project will not be certified, which will result in the landfill receiving a lower dollar per kilowatt from the power purchase agreement, resulting in a lower revenue generation.

Inconsistent gas quality and flow can dramatically affect the output of a landfill gas-to-energy project. Seasonal temperature changes need to be taken into account when developing a project and when negotiating a power purchase agreement as weather can alter the landfill gas production. For instance, summer production can be over twice the amount realized during winter.

The type of waste previously and currently being disposed in the landfill needs to be taken into account when estimating the gas production. Failure to do so will cause a mismatch between the gas generation, generation equipment and energy output. A landfill's operation and configuration can lead to lower then expected gas production. Recycling the landfill's leachate increases the landfill gas production by speeding up the decomposition process. The type of waste also affects the rate of gas production. Organic waste is the best for landfill gas generation. Recycling green waste such as grass clipping and removing them from the landfill actually slows down the generation of gas, and construction wastes take up a large volume of the landfill and decompose slowly, thereby reducing the landfill's gas produced per cubic foot of space. However, the benefit of recycling organic waste far outweighs the gas generation potential, for recycling reduces the need to create new materials that require much more energy to produce.

Understanding all of the technical issues and developing a mitigation plan to each can help the landfill or developer avoid many technical hurdles. Reviewing the history of the landfill and understanding the landfills waste composition and design will eliminate most of the technical hurdles. The landfill and developer should also be reasonable in the

amount of energy output; by keeping it within that specific range, many landfills could have successful projects.

The environmental benefits of landfill gas-to-energy projects are not as clear as other renewable energy projects and therefore can encounter public opposition. While the benefit of generation electricity from a normally wasted energy source is unquestionable, many groups oppose landfill gas to energy projects because of the connection to a landfill. Groups that oppose the projects have many reasons in doing so ranging from noise and emissions to ideological philosophies about consumption.

The landfill's location can cause permitting issues that do not allow some landfills to develop a project. To implement a landfill gas to energy project the landfill's existing air permit must be revised. The revised air permitting process is the most common barrier encountered when in developing a landfill gas to energy projects. The typical revised air permit shows an increase in carbon-dioxide emission and lower methane emissions. Many public opposition groups see that increase in carbon-dioxide as the landfill increasing its emission. However, as a greenhouse gas, methane (the major component in landfill gas) is considered 21 times more potent than carbon dioxide[12]. Additionally, the air permit requirements are very different between a landfill that flares its gas to one that generates electricity from the gas. This is due to the higher nitrogen-oxides (NO_x) produced from the combustion process. The higher NOx levels cause tighter restrictions on other operations occurring at the landfill. The higher NOx levels are being addressed by newer engine technology that significantly reduces the emissions.

Noise emission is another hurdle the landfills must overcome. While the majority of landfills are located in non-residential areas, some have been enveloped by urban growth. These landfills, in an attempt to be a good neighbor, must continually reduce their noise emission. Landfill gas-to-energy projects have a higher noise emission than the normal flaring of the gas. To be permitted by local governments, landfills usually must install sound insulation. Educating the public on the installation and the actual noise emission must be part of the landfill's permitting process.

5.3 Barriers faced by food processers

While anaerobic digestion offers potential energy savings, the benefits often do not merit the cost of implementation of anaerobic digestion for food and beverage facilities.

Land application is still the least expensive disposal means available for wastewater treatment. However, the benefits to anaerobic digestion over land application of wastewater include reduction in odors generated and reduction in nitrogen land application rates and subsequent need for downstream nitrogen removal facilities. Of the

[12] United States Environmental Protection Agency, General Information on the Link Between Solid Waste and Greenhouse Gas Emissions, available at: www.epa.gov/climatechange/wycd/waste/generalinfo.html

food processers that have installed anaerobic digesters, most have done so to meet waste regulations.

In addition, the cost of energy over the last 15 years has not warranted the capital expenditure to install systems to use the produced methane. Thus, many of the digesters used by food processers are simple lagoon style with the outdated methane collections systems that are in poor maintenance. Usually, the methane is flared.

The most practical means of biogas recovery for food and beverage facilities is natural gas supplementation for facilities with gas fired boilers. Recovery in boilers can typically convert incoming fuel to steam with about 80% efficiency. As the costs of energy (and natural gas in particular) increase, many food processors are investing in on-site boilers to facilitate the use of biogas. The capital cost associated with the infrastructure to clean the biogas to pipeline quality is still prohibitive. However, as the need for mobility of biogas increases (i.e., to transport the biogas to onsite equipment), the economics may justify the cost to clean the gas. For example, Glanbia has a propane powered process that could substitute biogas for natural gas if it could be cleaned. Conversion of the biogas to electricity is less efficient. Cogeneration equipment normally converts about 30-40% of the incoming energy of the biogas to electricity.

With proper public education, there is little community resistance expected.

5.4 Barriers faced by digester developers

Economic barriers are the primary barriers for digester developers in Idaho; for the most part, the technology exists and the community has responded positively.

A major economic barrier to developing biogas fueled electrical generation projects in Idaho is the high cost of interconnection to the utilities. Because most of the biogas projects will be located in rural areas far away from the population centers that demand the most energy, the power has to cross significant utility infrastructure. Oftentimes, over 10% of the total project cost is allocated to interconnecting the generators to existing distribution lines and upgrading the infrastructure to enable power distribution. Under the current system, the digester provider bears the entire cost of interconnection even though the public, the utility, and the developer all benefit.

A typical analysis of a 10-year project lifecycle shows that a digester provider must invest 7-9 cents per kWh of power generated, with an initial capital investment of $3500-$5000 per kW of capacity. Selling the power under a PURPA contract typically yields 5.5 to 6.5 cents per kWh of power generated. This price structure loses money and therefore the investment tends to be unattractive without some form of incentive.

Digester technology itself is relatively robust and mature. However, digester providers face significant technical barriers in: (1) conditioning biogas to pipeline grade; (2) transporting the conditioned gas to existing pipelines; and (3) pretreating the feedstock,

such as manure, to remove sand and other inorganic materials before the manure is placed into the digester.

Community resistance to biogas digester projects is rare. If such resistance is present, it usually results from a lack of understanding of how these projects mitigate many existing environmental issues and odor problems and facilitate effective nutrient management for the host dairies.

5.5 Barriers faced by utilities

As with any energy project developed by the utility companies, economies of scale play a significant role. The larger the project the greater the economic benefit. For small projects, such as landfill gas to energy, cost over runs can quickly eliminate the project benefits.

As discussed above, the cost of interconnection is great. Idaho Power Company generally requires power producing facilities to upgrade the transmission network and/or the distribution system before entering into an interconnection agreement. In Idaho, the transmission lines are typically categorized as major transmission lines (>115 kV line voltage), sub-transmission lines (35-115 kV line voltage), and distribution lines (12 kV line voltage and lower). The biogas facilities adjacent to dairies would interconnect with the 12 kV distribution lines.

The interconnection agreement process is regulated by the Federal Energy Regulatory Commission (FERC). To determine actual interconnection requirements a party desiring to interconnect and sell electricity must:

- File a Request to Interconnect with Idaho Power Company for Generators of < 20 MW,
- Complete a Feasibility Study,
- Complete a System Impact Study,
- Complete a Facilities Study, and
- Sign a Generator Interconnection Agreement

In general, the proposed seller, i.e. the biogas power facility, pays for the FERC interconnection process. The total process time to achieve execution of an interconnection agreement for a 2 MW generator may take a minimum 6-8 months to complete and cost over $50,000[13].

The FERC process involves three studies before an interconnection agreement is signed. The studies involve determining the feasibility, the system impact and the facility requirements to ensure that the project does not adversely affect the grid system.

[13] Idaho Dairy Waste Conversion to Electricity- A Pilot Project Feasibility Study- Final Report, October, 2004. Prepared for USDA, Bonneville Power Administration, Idaho Dairymen's Association by Mountain View Power, Inc. Boise, Idaho.

Performance of these studies is the main factor in the length of time required to obtain an interconnection agreement. The time from which an interconnection application is received to the physical interconnection can take between 12 to 18 months, depending on the amount of system upgrades required. In addition to the studies, interconnection equipment must be paid for. Such equipment includes: 3 way 12 kV switch on a new transmission pole to tie into the existing line; a 12 kv switch and breaker for protection; protective relays and meters; 12-5kV transformer, installed with foundation and oil containment; and a 5 kV generator breaker for each engine unit.

Utilities generally choose between two ownership structures: (1) the utility owns and operates the project, while the owner of the resource is paid a contract amount for the resource used; or (2) the utility enters into a power purchase and sale agreement (PPSA) with the project's owner where the utility and the project owner agree on a payment structure to purchase the output from the owner.

The utility must first demonstrate to the Public Utilities Commission (PUC) that the project is economically viable. The energy produced from the project must be of lower cost then the open market purchase. Failure of the project to produce this lower cost will result in the utility not recovering its cost from the PUC. Proving the economic benefit of the project is difficult, as environmental benefits are not major factors in the project approval. Additionally, biogas-to-energy projects have significantly higher dollar-per-kilowatt costs than other energy projects. Projects often are not economically viable unless production incentives exist. Examples include the renewable energy production tax credit, sales from green certificates, and customer participation programs (such as Rocky Mountain Power's Blue Sky Program).

Utilities face reduced liability when the utility enters into a PPSA with the project owner. However, several economic barriers remain. The power purchase cost must be competitive with the open market. The PUC allows utilities to pass the power purchase cost to the customers only if the cost is reasonable and then only through a regulated rate increases.

Utilities face a financial risk if the owner fails to provide reliable power. To meet load demand, a utility must be able to depend on the output from the biogas to energy project. The project's availability and capacity must be met for the power to be dispatched properly. As most biogas projects are the not the main source of revenue for the owner, maintenance may be insufficient to maintain reliable production. If the owner cannot reliably supply the output, the utility must purchase the balance on the open market, which tends to have higher rates than the rates negotiated in a PPA. This higher market rate cost is typically not recoverable from the PUC. Contracts between the owner and the utility that include reliability/output guarantee clauses are a possible avenue to address this concern.

<u>Example: Idaho Power's PPSA requirements</u>

Idaho Power Company's PPSAs usually contains the following basic conditions: (1) proof of "qualified facility" (QF) status; (2) an opinion from the seller's legal counsel that all required permits and QF status are valid and legal; (3) an engineer's certification of design and construction adequacy and operations and maintenance policy; (4) insurance; and (5) compliance with the Company's (and FERC's) interconnection requirements.

On July 30, 2008, the Idaho Public Utilities Commission ("PUC") approved a Firm Energy Sales Agreement ("Agreement) between Idaho Power Company and DF-AP#1 LLC (aka Big Sky West Dairy). [14] The 20-year Agreement sets the terms for the dairy to design, construct, own, maintain and operate an electric generation facility adjacent to the Dairy and sell 1.5 MW of firm electric energy to Idaho Power. The facility will be located approximately 7 miles southwest of Gooding, Idaho and was scheduled to begin delivering energy to Idaho Power in November 2008 with a Scheduled Operation Date of February 14, 2009.

According to the terms of the agreement, the dairy must maintain its status as "qualifying small power production facility" under PURPA, secure all necessary permits, and satisfy all interconnection requirements. The Agreement also included unique provisions that allowed adjustments of the published avoided cost rates to distinguish between heavy load and light load hour rates.

The PUC closely scrutinized the Agreement's requirement that the dairy post liquid security for online delay damages, which are equal to the estimated difference between the contract rates and market energy costs, multiplied by the project's expected monthly energy generation. This issue is very important to the smaller dairies in Idaho, for the Agreement required the Dairy to post between $10,000 and $200,000 as delay security. The PUC was concerned that operators of qualified small power production facilities do not have ready access to the necessary amount of security this Agreement requested. The security amount was ultimately deemed reasonable by the PUC, but the approval order stated that deposit amounts must be a fair and reasonable offset of the utility's costs and not be punitive in nature.

The majority of biogas to energy projects is small in output but have huge impact on infrastructure operation. Thus, grid imbalance is a major technical barrier for biogas to energy projects. Grid availability and capacity are related barriers. Upgrades to the system are critical in maintaining balance on the grid. Without proper upgrades, the system would become unbalanced and customer service would become unreliable. Upgrades such as protection relay, generator and substation breakers, and transformers all require planning and procurement of new equipment. The barrier to the system upgrade is the short planning performed on many small projects in which on-line dates are critical to project economics.

Community/service barriers exist due to the poor public awareness of issues around power purchasing, interconnection, and grid management. Interconnect agreements and regulations are complex. Without a better understanding of these processes and

[14] All documents are available at http://www.puc.idaho.gov/internet/cases/summary/IPCE0809.html.

associated issues, the public tends toward a low willingness to pay for higher renewable energy costs. Education and outreach efforts that also explain the benefits associated with renewable energy utilization will be needed to overcome this lack of support.

These barriers pertain to natural gas utilities as well as the electric utilities. Biomethane must be cleaned and certified to be pipeline quality as outlined by the FERC before it can be accepted into the utilities system. Constant and consistent monitoring must be done to ensure this quality is maintained. Transportation to the utility can either be accomplished by trucking the biomethane under pressure to be off-loaded to the utility or by building a gathering system and/or pipeline which could interconnect with the utility. Both options are expensive and the pipeline option could bring up further questions as to which governmental agencies jurisdictions the dairy or co-op might fall under.

6 Recommendations:

This report considered and analyzed ten different options for pursuing biogas development in Idaho: (1) single dairy digester with direct use; (2) community dairy digester with direct use; (3) single dairy digester to clean to pipeline quality gas; (4) community dairy digester to clean to pipeline quality gas; (5) single dairy digester to generate electricity; (6) community dairy digester to generate electricity; (7) food/beverage industry wastewater digestion with direct use; (8) food/beverage industry co digestion with other waste streams to generate electricity; (9) landfill gas to energy with direct use; and (10) landfill gas to energy to generate electricity.

These ten options were compared to each other based on several factors: (1) cost and economics, including production cost, tax base enhancement, development risk, deployment time, transmission requirements, business friendly environment, and capital intensity; (2) preservation of natural environment, including water use, footprint, greenhouse gas emissions, and health and safety; (3) reliability and security, inducing electricity grid, resource/fuel security, dispatchability, and adaptability; and (4) sustainable growth, including positive or negative job impacts, public acceptance, and national energy security. The results of this comparison are displayed in Appendix A, Table 1.

The Biogas Task Force believes that all ten of these options would benefit the state of Idaho if the economics pencil out. At this time, full scale deployment of anaerobic digestion at landfills is probably not feasible, although with time landfills may be better positioned to employ these technologies. The food and beverage industry will continue to pursue wastewater processing through anaerobic digestion as the costs begin to decrease. The option with the most likelihood of success in the immediate future is anaerobic digestion of dairy waste.

Of the six separate options for operating anaerobic digesters on diaries, the most viable option is a community digester where the waste from several dairies is used to generate electricity that can be sold to the utility companies. Various ownership structures are possible, and the needs of the dairies and communities involved should determine which

ownership structure will be employed in each community. Single dairies that have the capital and a risk portfolio that would enable the dairy to have its own digester should be encouraged to pursue such investment, given the environmental benefits and profit potential. In general, onsite use of the biogas or generating electricity from the gas is recommended over cleaning the gas to pipeline quality. As the technology needed to clean the biogas continues to improve and costs go down, the option of selling the biogas to the natural gas utilities will become more attractive.

6.1 Strategies to enhance success of anaerobic digestion

Strategies that would enable or encourage development of biogas resources and use of biogas generated energy are considered below. It should be noted however, that compared to other potential renewable energy resources being evaluated by the Idaho Strategic Energy Alliance, the potential energy offset, economic return, and job creation by development of biogas is relatively small. This task force, therefore, recommends that strategies that will enable renewable energy development across resources should be given priority consideration. Strategies that specifically enable biogas to the exclusion of development of other resources are not practical. In addition, the Biogas Task Force recommends that the actual costs of implementation of these strategies be quantified/evaluated by the Economic Development Task Force. Potential environmental benefits associated with biogas generation, as well as with other renewable resource utilization, should be quantified to the extent possible by the Economic Development Task Force.

6.1.1 Renewable Energy Enterprise Zones

Renewable Energy Enterprise Zones are regions where local units of government develop long-term strategies to support renewable energy enterprises within their jurisdictions. The strategies include local tax incentives, infrastructure such as roads, educational support, zoning and permit considerations, and other aid. These can be particular effective where units of government combine to offer consistent strategies throughout the area where the renewable resources are located.

Biogas development in the south central part of Idaho could benefit from application of this concept. For example, it will take local assistance and cooperation to create centralized methane purification facilities and the road and pipelines to link them to dairies. Local tax incentives and road enhancement and maintenance would help more digesters to be built and properly maintained. Educational institutions such as the College of Southern Idaho could provide trained technicians to operated and maintain facilities.

The Office of Energy Resources has worked to implement the concept of Renewable Energy Enterprise Zones in Idaho. Legislation defining REEZ and providing state tax incentives was introduced in the 1st regular session of the 60th legislature as House Bill 122, but was withdrawn. It may be re-submitted in a future session.

To promote local adoption of the REEZ concept, OER is devoting some of the monies received under the American Recovery and Reinvestment Act of 2009 (stimulus) to fund proposals from local units of government to create and provide start up resources to some REEZ in Idaho.

All options for development of biogas generation and utilization approaches within or outside of a REEZ will require interaction and agreements with utilities and the Public Utilities Commission. As described in this report, approvals and agreements can be difficult to negotiate. PUC consideration of environmental benefits when approving projects, and contracts with utilities that contain reliability/output guarantee features could help mitigate these concerns.

6.1.2 Legislative Support

Establishment of a statewide renewable energy portfolio standard or carbon emission cap may not be immediately feasible in Idaho, however if the federal government enacts legislation that establishes a standard or emission cap, Idaho's quick compliance would likely strengthen the renewable energy industry including use of biogas. Such actions could promote non-traditional revenue streams such as tradable Renewable Energy Credits (RECs) and carbon credits. Developers who are currently investing in these projects are generally banking on a significant upside both on power price and on the value of these environmental credits. Lack of renewable resource portfolio standards and of a mandatory carbon cap and trade system have kept the price of both of these credits low domestically. Legislation both on the federal and regional level to implement stringent but realistic renewable portfolio standards and mandatory carbon emission caps would cause the market to value these credits at a much higher rate, and returns on developer investment would improve greatly. Greater returns allow the developers to invest in smaller projects and would facilitate the generation of biogas here in Idaho.

Amending the state tax code to incent renewable energy production should also be considered. Idaho currently has a property tax exemption for wind and geothermal energy producers. If extended to all renewable energy production, this would be an incentive that could help the industries discussed in this report off-set the cost associated with installing and operating anaerobic digesters. Idaho also has a sale and use tax rebate for qualifying equipment and machinery used to generate electricity from fuel cells, low impact hydro, wind , geothermal, biomass, cogeneration, solar and landfill gas. Currently the rebate is limited to projects or facilities capable of generating at least 25 KW of electricity. Reducing this threshold for biogas generation is suggested given the number of small dairies that would be involved in biogas REEZ. An alternative is to develop an another rebate scenario that is shared between farmers in a co-op model.

As pointed out in this report, environmental benefits and regulatory compliance (treatment of wastewater, reduction in ground water nitrogen loading, odor abatement, etc.) are often drivers for anaerobic digestion. Stricter environmental regulations and consistent enforcement of those regulations would likely promote greater use of anaerobic digestion of waste. This combined with the above incentives and the

increasing demand and cost of energy will enable more industries to capture and utilize a resource that would otherwise be flared and wasted.

Regardless of these state actions, it is recommended that the state closely monitor and respond to federal legislation and environmental rulemaking that will seek to reduce greenhouse gas emissions and increase renewable energy production.

6.1.3 Community Outreach and Education

Educational programs are an important factor in the success of biogas development, regardless of the sector. When the digester is owned and operated by the dairy, the landfill, or the industrial company, the staff will need training. This issue is not as important when the digester is developer owned and operated. The community will also need to be educated; a community that understands the benefits of anaerobic digestion will embrace the technology, and students who become interested in the technology will facilitate improvements for the next generation of digesters.

6.1.4 Research and Development

Several universities around the state are already operating anaerobic digesters and engaging in important research and development. Collaborative programs, such as the Center for Advanced Energy Studies (CAES), should be supported and expanded. Universities and community colleges should add courses in anaerobic digestion technology to their catalogs. Currently the Bonneville Environmental Foundation funds a private grant program aimed at installing small scale solar systems at schools interested in increasing the visibility of renewable energy. Projects include outreach and educational components to encourage adoption and use of photovoltaics. The state should consider a similar approach to outreach and education regarding the environmental benefits of biogas production and use. A possible approach is to establish a grant program for teachers/educators to work with high school students in cooperation with the planned Center for Livestock and Environmental Studies through the University of Idaho. Finally, the state should pursue all available options for federal funding.

Appendix A:
Risk and Benefit Matrix and Rationale, Observations and Assumptions

Table 2: Summary of Risks and Benefits of Biogas Options

Ranking: **High Risk / Low Benefit** **Medium Benefit & Risk** **Low Risk / High Benefit**

Resource Biogas		Primary Attribute	Cost & Economics (1)	Preserve Natural Environment (3)	Reliability & Security (2)	Sustainable Growth (4)
		example attributes	production cost tax base enhancement development risk deployment time transmission requirements business friendly process capital intensity	water footprint carbon dioxide & other GHG health and safety	electricity grid resource/fuel security dispatchability adaptability	job impacts (+ or -) public acceptance national energy security
Score Range 0 -- 10						
Option 1	**Single dairy digester- direct use**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**3**	**7**	**8**	**6**
Option 2	**Community dairy digester- direct use**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**5**	**7**	**8**	**7**
Option 3	**Single dairy digester- pipeline quality gas**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance

			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**2**	**7**	**8**	**7**
Option 4	**Community dairy digester- pipeline quality gas**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**4**	**7**	**6**	**7**
Option 5	**Single dairy digester to electricity**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**2**	**7**	**6**	**6**
Option 6	**community dairy digester to electricity**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			

			business friendly process			
			capital intensity			
		Average Score	**4**	**6**	**7**	**6**
Option 7	**Food/beverage industry wastewater digestion-direct use**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**5**	**7**	**8**	**5**
Option 8	**Food/beverage industry co-digestion with other waste streams to electric generation**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**6**	**7**	**7**	**6**
Option 9	**Landfill Gas to Energy - Direct Use**		production cost	water	electricity grid	job impacts (+ or -)
			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**5**	**8**	**8**	**6**
Option 10	**Landfill Gas to Energy - Electricity Generation**		production cost	water	electricity grid	job impacts (+ or -)

			tax base enhancement	footprint	resource/fuel security	public acceptance
			development risk	carbon dioxide & other GHG	dispatchability	national energy security
			deployment time	health and safety	adaptability	
			transmission requirements			
			business friendly process			
			capital intensity			
		Average Score	**4**	**8**	**7**	**3**

Option 1- Single dairy digester -direct use

Cost and economics:
Intense upfront capital cost and ongoing operation costs are barriers. Capital costs can be anywhere from $5-10 million. For a third party developer, it is estimated that the average costs for installation of a single dairy digester for medium to large dairies (around 5000 head) is $1300 per head or $6.5 million. On site use with boilers are considerably less expensive than on site electricity generation because of the cost of generation equipment and maintenance. Boilers can save as much as $750,000 in costs compared to electricity generation.

Building a digester as part of the diary operation would provide minimal tax base enhancements.

The development risks are known as digesters are commercially available technologies. Deployment time is reasonable given it is a known technology and several have been deployed in Idaho. There is little transmission requirement as energy requirement and use are on site. Direct use would generally mean the digester is independent operator owned so there is little to no incentive for business to own and operate. The upfront capital costs are high and retrofit costs to utilize energy can be high.

Environment:
Manure management reduces the risk of groundwater and surface water contamination. On site deployment typically requires a small digester depending on technology used (estimated size for a 5000 head dairy is 300 ft X 150 ft by 16-18 ft deep), which is a relatively small footprint. Anaerobic digestion has been demonstrated to reduce greenhouse gas emissions. The reduced risk of groundwater contamination and reduced nitrogen land application provide reduced health and safety risks.

Reliability:
No electrical grid concerns because of the direct use application. There is essentially no resource security risk because the digester is located at the source. Dispatchability is also low risk as digesters can be located and developed at each dairy if fuel source is sufficient

to warrant cost. Adaptability is good since the generated gas can be used to offset propane, natural gas, and fuel oil use or to produce electricity on site.

Sustainable growth:
Job impact is minimal with an estimated increase in jobs of 1 or 2 people for on site operation of the digester. Public acceptance is generally good due to odor reduction and water quality improvement. National energy security impact is minimal since the energy use offset is to individual dairy energy consumption only.

Option 2: Community digester- direct use

Cost and economics:
As in option 1, capital and operation costs are barriers but could be mitigated somewhat with community approach. Economy of scale can be realized with a larger digester. Capital cost of digester installation is estimated to be $1000 to $1100 per head for dairy operation of greater than 10000 head. A community digester could create a new entity (such as a cooperative) that would enhance the tax base. Development risks are known and the technology is available and therefore deployment risk is low. Transmission requirements are slightly more costly and uncertain than with direct use on an individual dairy since the produced gas must be shared with multiple dairies. This could require piping or trucking considerations. As with the single dairy, with a co-op there is no incentive for the developer and the upfront capital costs are high.

Environment:
Same assumptions were made as for single dairy-direct use except that the footprint will increase with the larger digester needed to accommodate numerous dairies.

Reliability:
Same assumptions were used as for single dairy-direct use.

Sustainable growth:
Job impact is greater than for a single dairy operation as a community digester project would crate a new entity to operate and maintain digester therefore creating some jobs in rural areas. While there are the same benefits of an individual dairy digester with respect to odor control and water management, there may be an acceptance issue with transporting raw manure to the community digester. The national energy security impact is still low since the energy offset is for dairy energy consumption only, however with numerous dairies participating the energy use offset will increase incrementally

Option 3: single dairy - pipeline quality gas

Cost and economics:
Capital costs are average when compared with other forms of biofuels and are similar to on site use, however the costs of transmission (pipeline construction) must be considered if the dairy or a third party assume those costs. Deployment time is reasonable depending on the type of transmission and considering the extra time to construct pipelines if not

already present. If biogas is transported via truck to a drop location, labor, vehicles, and compression is required. Other attributes similar to single dairy direct use but with added cost to test and clean the gas.

Environment:
Similar to direct use, however monitoring the biomethane to ensure pipeline quality will be an ongoing process adding to the operation costs. This monitoring will ensure a safe and reliable fuel. Possibly the greatest benefit is mitigating the odor factor in and around the dairy farm.

Reliability:
Using biomethane directly in motor vehicles, boilers, or heating processes is the most efficient use. Use as pipeline quality gas requires a constant source of biomethane which is could be a problem for small dairies.

Sustainable growth:
The assumptions are similar to single dairy direct use, however, with incentives for consumers to purchase the renewable gas (perhaps at a higher cost) a greater offset of energy consumption could be realized.

Option 4: Community dairy- pipeline quality gas

Cost and economics:
Capital and operating costs are similar to community dairy projects for on site use depending on digester/production size. Pipelines are more feasible for community dairy projects than single dairy pipeline gas use as the dairies can share the construction, installation and pipeline costs. Other attributes similar to direct use but with the added cost to test and clean the gas.

Environment:
Monitoring the biomethane to ensure pipeline quality will again be necessary . This monitoring will ensure a safe and reliable fuel. As with the community digester for direct use, the greatest benefit is mitigating the odor factor in and around the dairy farm.

Reliability:
Again, using biomethane directly in motor vehicles, boilers, or heating processes is considered the most efficient use, however, large community dairies will ensure a more reliable resource for pipeline use than single dairies.

Sustainable growth:
Job impact could be increased with a community dairy approach, including increased jobs for a third party entity that would operate the digester and transportation/distribution jobs.

Option 5: Single Dairy Digester- electricity generation

Cost and Economics:
Capital costs are generally around 10% higher for electricity generation than for on site boiler use. Interconnect costs can be as high as $500,000 for at typical 5000 head dairy which includes the physical connection at the site and the necessary upgrades of distribution lines to the main transmission lines. Even if the electricity is generated only for on site use, the cost of generators and maintenance can be significantly higher (as much as $750,000) than for boiler use.

Environment:
Environmental concerns and benefits are similar to single dairy digesters for on site or pipeline gas use.

Reliability:
Reliability is a larger concern since electricity generation requires consistent and sufficient gas quality and flow. Since gas generation varies by size of dairy and dairy operation, this is especially problematic for individual dairies.

Sustainable Growth:
Job impact may be slightly increased due to the need for maintenance and development of interconnections, however this is short lived. In general the growth potential is still considered small. The number of dairies that meet the criteria needed to produce sufficient electricity for sale to the utilities is small, therefore the replacement of electricity with a renewable source in Idaho is also quite small for this scenario.

Option 6: Community Dairy Digester- Electricity Generation

Cost and Economics:
The capital costs are similar to large (>10000 head) dairies, and could be more manageable for multiple dairies that would split the costs or a 3rd party developer that would own and operate the digester for a cooperative. Interconnection costs are still considered the biggest hurdle.

Environment:
The footprint would be similar to that for any community dairy digester whether for on site use or pipeline quality gas. The environmental benefits are also similar.

Reliability:
As with single dairies and electricity generation, the biggest issue is the reliability of the gas flow and quality, although this can be better managed in a community dairy approach.

Sustainable Growth:
All factors are similar to community dairy digesters for on site use or pipeline quality gas.

Option 7: Food and beverage Processing Industry –Wastewater Digestion -direct use

Cost and economics:
Production costs are generally not an issue for food processors if they are treating their waste streams anyway since cost is already embedded in waste disposal costs. Food processors that already capture and flair the gas are ideal candidates since the capital cost of digester can be minimal and require only upgrades. Otherwise, this is a capital intensive proposition ($1-10M for installation of digester) and for most food processers in Idaho, the benefits do not merit the implementation of anaerobic digestion. If digestion is implemented, the decision to recover the biogas for use is generally an economic one. There is a development risk present unless direct use at point of generation is already in place, however the development time is minimal as the technology is well developed and deployment time is minimal. Transmission requirements are low for on site use. This is considered a neutral business friendly process however, there are no drivers other than energy cost savings at this time.

Environment:
There is no major demand on water supplies and there is a potential benefit through reduction in waste disposal. The environmental driver for the food processors is reduction in chemical oxygen demand, however land application of waste is still the most economical approach. Digestion and use of biogas can provide reduction of odors and some nitrogen loading reduction as compared to raw land application of waste. The footprint-size varies with need, large and small options are available. As with the other biogas resources, carbon dioxide and greenhouse gas emissions are reduced as the methane is destroyed. Methane safety could be an issue but the risk is manageable via safe design.

Reliability:
Resource security is considered low risk for on site use because waste materials are widely available and stable without any security issues. This is not an on demand process as notable start up and shutdown time is required. This is considered an adaptable process with application to many food processing waste streams and various feed stocks can be acclimated over time.

Sustainable Growth:
Limited manpower is needed and can often be accomplished with existing staff, therefore no substantial impact to jobs positive or negative. The concept is rapidly gaining popularity for odor control and the public is not overly concerned about methane safety. The feedstock is readily available and secure.

Option 8- Food and beverage processing industry- co digestion of waste- converted to electricity

Cost and Economics:

Production Cost is roughly $400- $500 per MWh Installation cost and feedstock is inexpensive if it is considered a waste and disposal costs are offset. Capital cost of digester installation can be high, $4-5M per MW, however tax base enhancement for the industrial entity is therefore also good. The development risk is low, the technology is well understood. Logistics and agreements between parties are difficult. Deployment time is usually 1-3 years. Transmission requirements are low, power production is roughly equal to power usage. This can be a business friendly process since installation costs and performance are predictable and manageable as long as interconnection agreements with the utilities can be negotiated in a timely manner. Interconnection costs can still be the biggest hurdle.

Environment:
Water use can be relatively high but gray water re-use and recycling can offset the cost. Digesters in this scenario are relatively large compared to dairies and can have a significant footprint to the processor. As with other digesters, this scenario can greatly reduce greenhouse gas emissions and odors. Waste reduction can result in health benefits and production risks are known and manageable.

Reliability:
The technology for electricity generation is mature. Waste as a feedstock provides some resource security; however, the inconsistency of gas flow is problematic. The electricity can be easily distributed, and the process is easily adapted to new waste streams and other processing plants. If the interconnection agreements are well developed the cost to set them up remains the issue.

Sustainability:
Expect a positive but moderate impact to jobs due to the increased potential size of the operation compared to individual dairies, land fills, or food processors. Proper waste treatment with reduction in odors increases public acceptance. The co-generation of waste streams from multiple processors can generate more electricity than a single processor; however, the potential offset to energy use is still relatively low. This is because facilities that generate low COD waste streams are not good candidates for anaerobic digestion and many of Idaho's facilities fall into this category. Generation life can be 25 years plus if properly maintained.

Option 9: Landfill gas capture for direct use

Cost and Economics:
Installation cost can vary significantly depending on facility production and other contingencies. Estimated cost for unit is between $100,000 to $1.5 million depending on size and required direct use load. For small projects, such as landfill gas to energy, cost over runs can quickly eliminate the project benefits. Tax base enhancement has recently improved with the stimulus package that extended the production tax credit by three years. Transmission upgrades are minimal, if any. The risk with development is that the full resource potential is not known until it is placed in service. The capital expense is higher compared to a flaring process. The cost benefit exists in offset of heating costs.

However, the high initial cost my not be completely offset by reduced energy cost. Pay back term can be long (years). Development time is minimal as equipment is typically available within a reasonable time frame. Maintenance costs are higher compared to flaring process.

Environment:
The foot print of the digester has minimal impact as it is located on the landfill site. There is minimal benefit to water as more gas is extracted and less is leached into ground water system however there will be increased water use due to heat the transfer medium. Greenhouse gas emission reduction is realized as with all forms of anaerobic digestion. Health & safety issues are minimal and can be resolved by industry standard protection.

Reliability:
Inconsistent gas quality and flow, especially seasonal temperature variations, can dramatically affect the output of a landfill gas-to-energy project. Resource fuel security is not an issue since fuel for direct use is created on-site from waste. Dispatchabilitiy is not applicable on site. The system can be added on to for increase direct use or generation.

Sustainable Growth:
Increase in jobs is minimal. Expected 1-2 jobs created for equipment maintenance and operation based on industry standards. Pubic Acceptance is expected to be good as direct use is mainly for heating landfill building or close by buildings. Direct use does offset local energy use potentially keeping utility prices lower. Noise is not considered an issue. New landfills and digesters require permitting already so no public comment is needed. There is little benefit to national energy security since direct use is completely local. Does offset heating with coal and natural gas at the local point of use.

Option 10: Landfill gas capture converted to electricity

Cost: and Economics:
Direct capital cost range from $4,000 to $5,000 per kilowatt. Operation and maintenance of a facility can range from $.04 to $.07 per kilowatt hour. Similar issues as with direct use but with added cost of interconnection agreements which may lead to costs that are not offset by the benefits. There is also a long lead time for engine-generator sets. Lead-time can exceed 1 year. Maintenance costs compared to flaring process are higher. 1-2 additional staff may be needed but maintenance assumed by existing staff reduces risk.

Environment:
Minimal impact or benefit on water as more gas is extracted and less is leached into ground water system. A potential health & safety issue is the increased noise which can cause a minimal health impact. This can be resolved by industry standard protection.

Reliability:
Once the interconnection agreements are in place, there is minimal if any issue with grid reliability. However, reliability of the resource is a concern, especially with the seasonal

gas flow issues that are encountered in Idaho. There is very low national energy security benefit given the low number of qualifying land fills in Idaho. Electricity can be dispatched. Units operate more efficiently under base load conditions. Systems can be added on to for direct use or increase generation.

Sustainability:
Public acceptance depends on the local public. Some groups have opposed projects other welcome them. Education is required if opposition is seen. National benefit is minimal, generation is completely generated locally and generation levels are low. Generation life is long and projects can produce for up to thirty years after landfill closure.

Appendix B.
Landfill Gas Estimation Procedures

There are three ways to estimate the landfill gas production. The three methods, A, B, C, range from quick estimate calculations to field measurements calculations. The easiest method to estimate the landfill gas production is method A. Method A uses the estimate that for each pound of waste in place 0.1 cubic feet of landfill gas is generated. While Method A is a simple approach it can be off by approximately 50%. This method is only useful in doing quick calculation as to the landfills potential[15].

Using this estimate the equation for Method A appears below:

Annual Landfill Gas Generation (cf) = 0.10 cf/lb x 2000 lb/ton x Waste-in-Place (tons)

Method B is a first order decay method in which the landfills average waste acceptance, years of operation, and waste-in-place are used. The method uses a decay constant which represents the rate in which methane is released from each pound of waste. The draw back to the equation is the value of the decay constant and gas rate per pound of waste can vary greatly. The equation is more accurate if the landfill is currently flaring the landfill gas. In which data collection can be used to determine the gas per pound rate. With data the method can still contains a accuracy range of 50%.

The first order decay model is shown below:

$$LFG = 2L_0R(e^{-kc} - e^{-kf})$$

Where:

LFG = Total amount of landfill gas generated in current year (cf)
L0 = Total methane generation potential of the waste (cf/lb)
R = Average annual waste acceptance rate during active life (lb)
k = Rate of methane generation (1/year)
t = Time since landfill opened (years)
c = Time since landfill closure (years)

The third method is a pump test. Method C involves drilling sample wells for data collection in a representative sample area of the landfill. Data is then collected from the wells. This data includes well head pressure, energy content, temperature, chemical make and flow rate. This information then can be used to determine the landfills methane production.

[15] Energy Production Measurement at the Whitesides Biogas Plant, August 2006. Prepared for the State of Idaho, Department of Water Resources, Energy Division, by Intrepid Technology and Resources, Inc. Contract #DWR-CON00719

While Method C is the most accurate of the three methods it also is the most expensive. Drilling and equipment cost can vary significantly from region to region. The method is best used once the previous two methods show some promise.

Additional modeling can be performed by landfill experts. A good model with proper input can produce a accurate representation of the land fills generation. The models analysis can become costly but the accuracy obtain allows for better due diligence in pursuing a landfill gas to energy project.

Once a landfill gas generation has been determine the amount of energy that could be produced can be calculated. Landfill gas typically has a energy per cubic foot value of 500 btu/cf, a value is approximately half that of natural gas. Using a simple equation the amount of power production can be calculated. An example of the calculation is shown below.

kW = LFG x EC x 1/HR x C

Where:

kW = kilowatt produced from power unit
LFG = Landfill gas flow rate (cf/d)
EC = Energy content of landfill gas (Btu/cf)
HR = Heat rate of power unit (kWh/Btu)
C = Conversion factor (0.04167 = 1d/24hr)

Using the above equation a land fill producing 1,000,000 cubic feet of gas per day has a potential generation ability of 1,736 kilowatts. This is based on a typical heat rate of a internal combustion engine of 12,000 kWh/Btu.

In order to determine the annual electricity generated the unit and landfills capacity factor must be determine. Typical landfill power equipment has a capacity factors ranging 75% to 90%. Using the below equation and the above power production a landfill with 1,000,000 cf/d will have an annual generation of 13,686 Megawatts hours per year.

Annual Electricity Generated (kWh) = Net Power Generation Potential (kW) x 24 hr/d x 365 d/yr x 90%

Using a power sales cost of $30 per Megawatt hour the annual revenue would be approximately $410,600.

Appendix C:
Status of Anaerobic Digestion and Energy Recovery for the Idaho Food & Beverage Industry

Prepared by HDR, Boise, Idaho
November, 2008

Status of Anaerobic Digestion and Energy Recovery for the Idaho Food & Beverage Industry

Prepared for the

State of Idaho

25x'25 Renewable Energy Council

November 2008
FINAL

HDR

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Introduction

In September 2007, Idaho Governor Butch Otter signed an executive order stating "it is the goal of the State of Idaho that 25% of Idaho's energy needs be provided through renewable sources by the year 2025 from our farm, ranch, timber and other working lands, while continuing to produce abundant, safe and affordable agricultural products." An establishment called the *Idaho 25 x '25 Renewable Energy Council* was initiated under this order to develop a coordinated approach to attain this renewable energy goal. One of the Council's tasks is to segregate and quantify the energy that could be obtained from a variety of renewable sources including wind, solar, biomass, geothermal and anaerobic digestion. A subcommittee was formed to specifically evaluate the energy that could be obtained through the anaerobic digestion of process wastewater from Idaho's food and beverage industry.

Wastewater generated during the production of food and beverage products is typically characterized by high chemical oxygen demand (COD). High COD wastewaters favor anaerobic digestion as a treatment method for various reasons including low excess sludge production, relatively small treatment system footprint and low overall energy requirements. For these reasons, anaerobic digestion is already practiced by several Idaho food processors.

This summary report was prepared by HDR and is considered a work product of the Council's subcommittee. Specifically, the report:

- Describes and identifies the number of Idaho food and beverage companies that could feasibly employ anaerobic digestion for treatment of wastewater from their processing operations
- Quantifies the biogas (and energy value) that could be generated from anaerobic digestion of the process wastewater from the Idaho food and beverage industry
- Estimates the quantity of biogas that is currently produced by anaerobic digestion of food and beverage process wastewater in Idaho
- Estimates the quantity of biogas that is currently recovered and utilized from anaerobic digestion of food and beverage process wastewater in Idaho
- Identifies potential uses for captured methane

Candidate Idaho Food and Beverage Facilities

HDR developed a list of Idaho food processing and beverage manufacturing companies (who remain anonymous in this report) that could feasibly implement anaerobic digestion and recover methane generated during the anaerobic digestion process. In essence, facilities that generate low COD loads (< 1,000 pounds per day) were excluded from the report since anaerobic digestion would not be practical for these facilities.

A variety of sources were used to develop the list of candidate facilities. These sources included:

1. Idaho Department of Environmental Quality (IDEQ) Land Application Permit Holders list
2. Environmental Protection Agency (EPA) National Pollutant Discharge Elimination System (NPDES) Permit Holders list
3. Publicly Owned Treatment Works (POTW) Pretreatment Coordinators
4. Online Business Directories
5. HDR Staff Experience

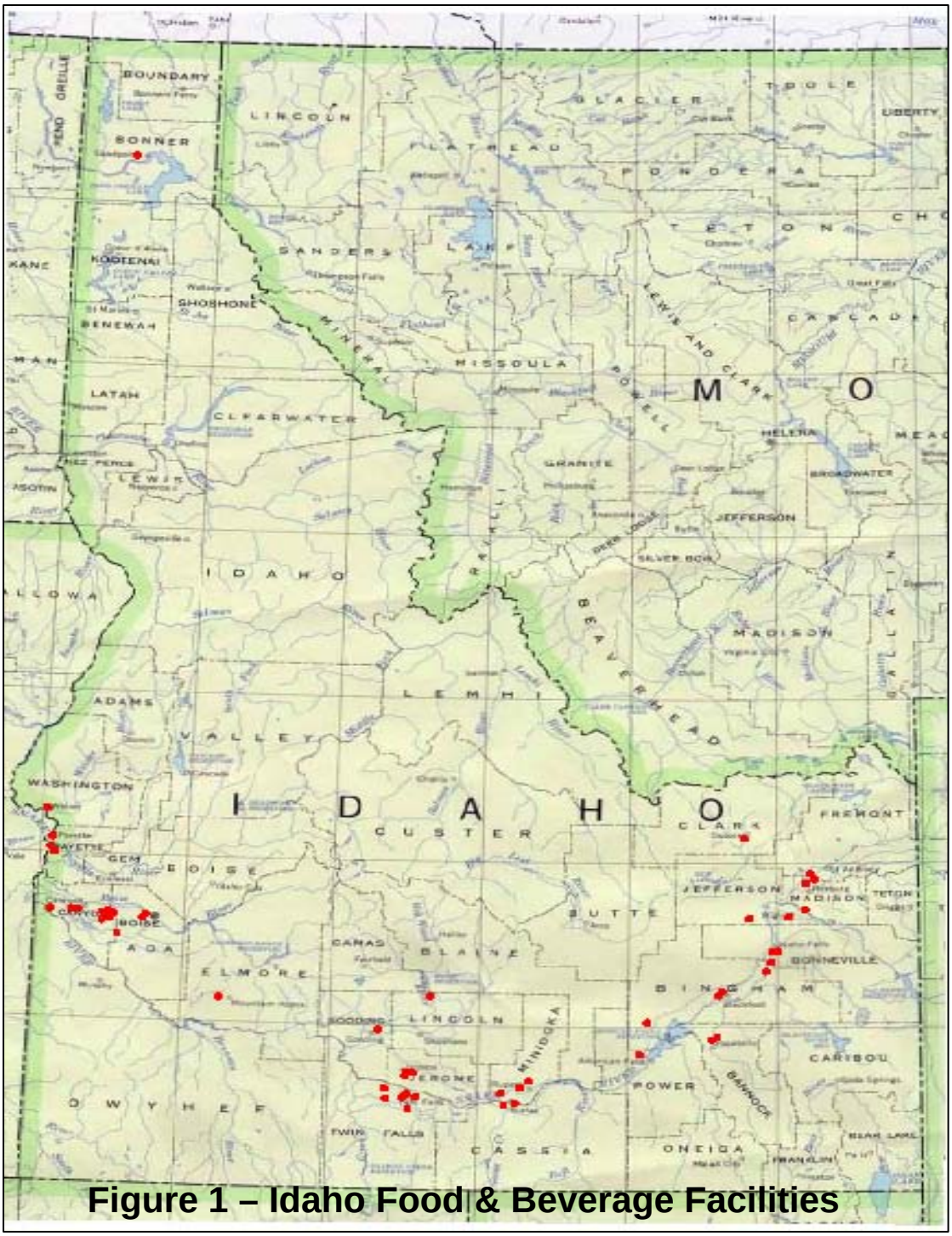

Figure 1 – Idaho Food & Beverage Facilities

The list of feasible candidates included 49 facilities. A map of these facilities is provided in Figure 1; locations are denoted in red. These facilities included beverage manufacturers and processors of vegetables, milk, meat and fish. Table 1 categorizes the industries by product type. HDR made two attempts via telephone and/or email to contact each of the 49 facilities regarding their wastewater discharge. Specifically, HDR requested facilities' average wastewater flow and

COD concentration. HDR was able to obtain information for 32 facilities. Wastewater information was obtained via direct communication with the facilities or through IDEQ or EPA public records. Engineering judgment was used to estimate wastewater flow and COD for the facilities where information could not be obtained otherwise.

Table 1
Summary of Idaho's Food and Beverage Industry

Industry	**Number of Facilities**
Potato	16
Dairy	14
Other Vegetable	9
Beverage	4
Meat	3
Fish	1
Miscellaneous	2
Total	*49*

Biogas generation was estimated using facility wastewater flow and COD data. The following assumptions were made in estimating biogas generation.

- Anaerobic digestion would achieve 80% average COD removal (removal could be lower or higher depending on type of wastewater being treated and treatment technology)
- One pound of COD removed by anaerobic digestion produces 5.8 scf (standard cubic feet) of methane
- Biogas has an average methane content of 65%

Table 2 summarizes the quantity of biogas (and its associated energy value) that could be produced by the Idaho food and beverage industry assuming all facilities used anaerobic digestion to treat their process wastewater.

The total amount of energy currently used in the State of Idaho is approximately 517 trillion BTU per year. On a per capita basis, Idaho's energy use is 353 million BTU per capita per year (US DOE). It is worth comparing the amount of energy that Idaho uses to the amount that could by produced by Idaho's food and beverage industry via anaerobic digestion. As shown in Table 2, the total amount of biogas that could be generated by the Idaho food and beverage industry is approximately 1.37 trillion BTU per year, which is equivalent to the energy use for a population of about 3,880. This energy production is only about 0.3% of Idaho's total energy use. Therefore, it appears biogas production from anaerobic digestion of food and beverage industry wastewater could only provide a small contribution to the Council's goal of 25% renewable energy use.

The estimated total annual biogas that could be produced by the Idaho food and beverage industry via anaerobic digestion is 2.11 X 10^9 scf. This annual biogas production is equivalent to 1.37 trillion BTU (British Thermal Units) of energy. The average and median annual potential biogas production for the facilities are 42.9 million scf and 26.1 million scf, respectively, which has an energy equivalent of 27.9 million BTU and 16.9 million BTU. If the biogas were converted to electricity at 30% efficiency, the average and median facility electrical power equivalent would be 0.28 MW and 0.17 MW. The total electrical power equivalent for all 49 facilities would be 13.7 MW.

Figure 2 breaks down the number of facilities across Idaho by the amount of energy available at each facility via anaerobic digestion. As shown, most facilities produce at the lower end of the energy range.

Table 2
Summary of Annual Biogas Production Potential and Associated Energy Value

	Facility Average	Facility Median	Total from all Facilities
Biogas that could be Produced Annually (million scf)	42.9	26.1	2,106
Annual Energy Equivalent (billion BTU)	27.9	16.9	1,370
Population Equivalent[1]	79	48	3,880
Electrical Power Equivalent (Megawatt) [2]	0.28	0.17	13.7

[1] Based on 353 million BTU per capita per year (US DOE)
[2] Assumes 30% electrical conversion efficiency

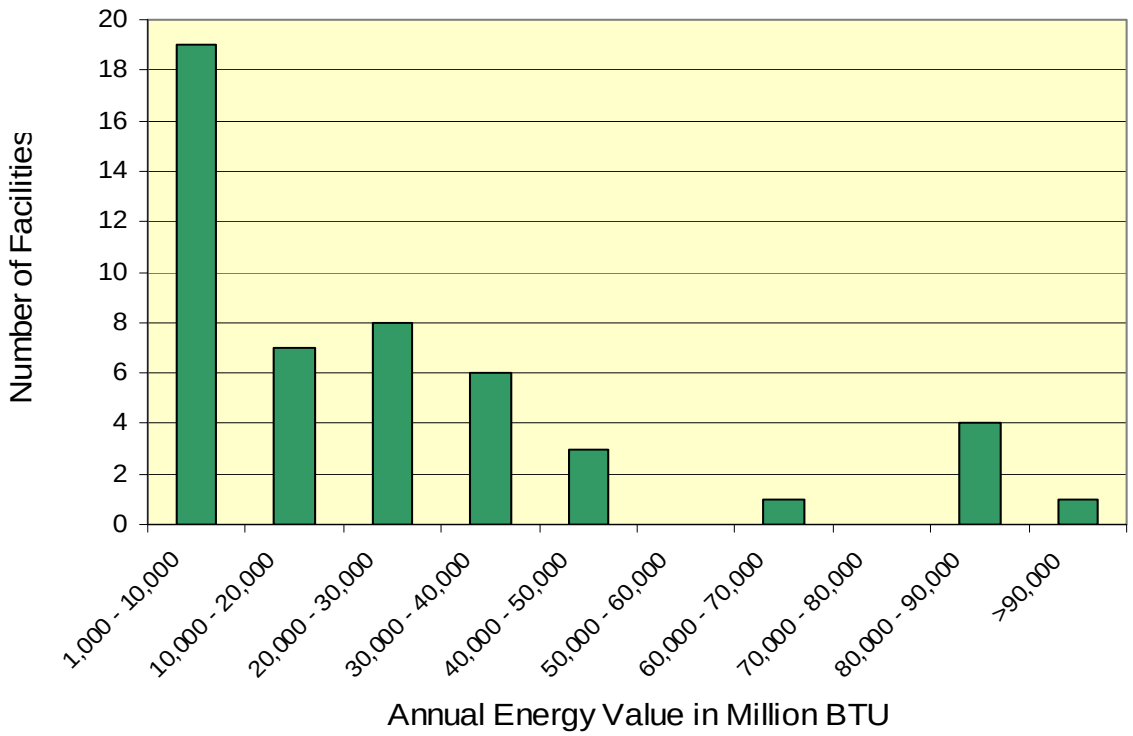

Figure 2 - Breakdown of Idaho Facilities by Energy Value of Biogas Production Potential

Current Status of Biogas Generation and Utilization

Of the 49 food and beverage facilities in Idaho, eight currently employ anaerobic digestion to treat process wastewater. Anaerobic digestion at these eight facilities yields an annual total energy production value of 542 billion BTU. It is worth noting that these eight facilities account for approximately 39% of the total biogas that could be generated from 49 candidate food and beverage facilities identified for this report. Of the eight facilities with anaerobic treatment systems, four facilities utilize the biogas in facility boilers. The remaining four facilities flare the biogas using waste gas burners. Approximately 65% (350 billion BTU) of the total biogas that is currently generated is utilized. No facilities burn the biogas to generate electricity. Table 3 summarizes the current status of energy that could be available via anaerobic digestion, the energy value of the biogas currently generated and the energy value of the biogas that is currently utilized.

Table 3
Current Status of Renewable Energy Recovery via Anaerobic Digestion in Idaho's Food and Beverage Industry

	Annual Total (million BTU)
Energy potentially available if all 49 facilities employed Anaerobic Digestion	1,370,000
Energy value of biogas currently generated by Anaerobic Digestion	525,000
Energy value of biogas generated that is currently utilized	350,000

Current Wastewater Disposal Practices for Idaho's Food and Beverage Industry

Land application is the most common method for disposal of process wastewater generated by food and beverage facilities in Idaho. The next most common disposal method is POTW discharge followed by direct surface water discharge. Land application is the cheapest disposal means available since wastewater treatment (other than screening and/or primary clarification) is normally unnecessary. At the same time, significant acreage is required for land application and application of untreated process wastewater can lead to foul odors at application sites. For these reasons, land application is typically practiced in rural areas where land is relatively inexpensive and fewer residents surround application sites.

Approximately half of the 49 facilities evaluated in this report dispose of their wastewater under IDEQ land application permits. In most cases, land appliers do not employ anaerobic digestion. The following circumstances are the most common reasons that a land applier would employ anaerobic digestion. In nearly all cases, the goal is to reduce wastewater COD.

- Excessive odors are generated at the land application site; COD reduction would decrease odor generation
- COD land application rates need to be reduced to meet permitted rates
- Nitrogen land application rates exceed permitted rates; COD reduction via anaerobic treatment reduces costs for downstream nitrogen removal facilities

- Concerns over pathogens in land applied wastewater; anaerobic digestion effectively destroys pathogens

The implementation of anaerobic digestion for facilities that discharge to a POTW or surface water is commonly driven by a permit limit and like land application, COD reduction is the primary goal.

Obstacles to the Implementation of Anaerobic Digestion for Idaho’s Food and Beverage Industry

While anaerobic digestion offers the benefit of biogas utilization and potential energy savings, this benefit alone does not merit the implementation of anaerobic digestion for food and beverage facilities. Other drivers such as those listed above normally trigger the need for anaerobic digestion. If anaerobic digestion is implemented, the decision to recover biogas or not is normally an economic one. Typically, the economic benefit of biogas recovery is weighed against biogas recovery capital costs. If the economics of biogas recovery fit the facility’s business plan and goals, biogas recovery is practiced. At the same time, a facility may implement biogas recovery to reduce its carbon footprint, reduce its overall impact on the environment or for other reasons.

The most practical means of biogas recovery for food and beverage facilities is natural gas supplementation for facilities’ gas-fired boilers. Facility boilers generally utilize significantly higher quantities of natural gas compared to biogas generated by anaerobic digestion and facilities can relatively easily blend biogas with natural gas and feed the combined gas stream to the boilers. This practice normally requires little to no biogas treatment prior to utilization. Recovery in boilers is also relatively efficient as a boiler can typically convert incoming fuel to steam with an efficiency of about 80%.

Conversion of biogas to electricity is less efficient. Cogeneration equipment normally converts about 30 to 40% of the incoming energy of the biogas to electricity. Excess heat is generated during cogeneration but finding a use for this excess heat can be difficult. Furthermore, biogas is highly corrosive to cogeneration equipment leading to significant cogeneration equipment maintenance or the need for biogas cleaning in some cases. For these reasons, cogeneration is a less attractive means for biogas utilization compared to fuel supplementation for gas-fired boilers.

Rising energy costs and the subsequent increased value of biogas over recent years has sparked interest for facilities to consider anaerobic digestion. Carbon credit markets have also led to greater interest in biogas recovery. The economic gain however from carbon credits is minor. It does not appear these incentives alone will lead to a significant increase in the use of anaerobic digestion in Idaho’s food and beverage industry. The following list of incentives would be needed for greater implementation of anaerobic digestion technology and biogas recovery for Idaho’s food and beverage industry.

- Increased emphasis on environmental protection and regulation of land application operations and discharge to POTWs
- Streamlined air and water permitting to avoid permitting complexities
- Tax credits for biogas recovery
- Significant rise in natural gas or electricity prices (Idaho has comparatively low energy costs compared to other states).

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