WISCONSIN SEO STATE ENERGY OFFICE

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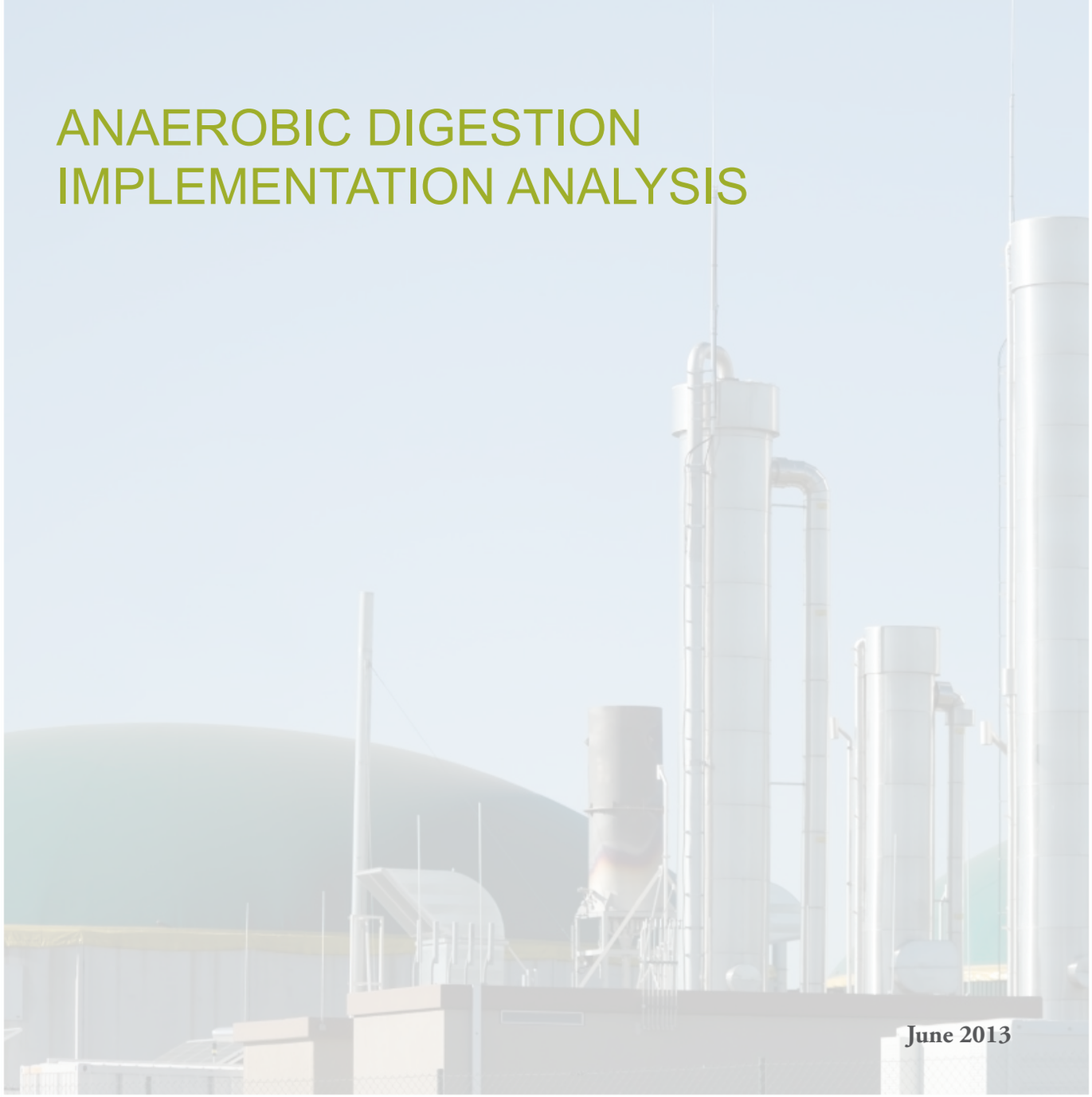
ANAEROBIC DIGESTION IMPLEMENTATION ANALYSIS



June 2013

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Forward

The State of Wisconsin Energy Office (SEO) issued an RFP in March 2013 to learn what policy drivers could be explored to further understand what could potentially help the development of biogas projects in the state. SEO's expectations of this RFP called for the following:

- Advancing their understanding of the economic and policy issues that can influence biogas energy projects in Wisconsin.
- Exploring the range of feasibility that would exist under different project conditions through the state or utility service areas.
- A contractor that has a working knowledge of Wisconsin and Federal rules and regulations as well as knowledge of financial incentives and options.

As part of this further exploration of what areas can make biogas projects economic, SEO has specifically requested an overview of the following subject areas:

- State, Federal and other incentives
- Cost and current overview of capital sources related to biogas
- Waste management cost review
- Utility service cost/price for electrical production
- Other potential primary biogas project drivers:
  - Waste heat, BioCNG to vehicle fuel, carbon credits, nutrient trading
- Regulatory overview including discussion of WI and other state limits of net metering

As a continuation of our prior Energy Applications from Agriculture and Cheese Manufacturing Feedstocks report and economic toolkit dated August 2012, Baker Tilly was asked to include an update to the economic tool kit which allowed for sensitivity analysis of certain primary project drivers learned in the above analysis.

This document is meant to give the SEO and other state agencies a clearer picture on the practical bottlenecks which exist for future biogas development in the State of WI.

Executive summary

Currently there are in excess of 100 anaerobic digestion systems in operation in the State producing biogas for heat and/or power applications. These systems range from small on farm digesters, to larger municipal and industrial applications.

Public and private stakeholders in the state should consider embracing strategies and approaches to encourage additional development of these projects for a number of reasons, to include, but not necessarily be limited to:

- Wisconsin is a dominant player on the national and global scale in terms of cheese manufacturing facilities and associated capacity. Its 126 manufacturing facilities are more than double that of the next closest state (California with 60) but also represent nearly a quarter of the facilities in operation in the United States. Cheese production facilities in many cases can provide an attractive feedstock for the potential development of a biogas facility.
- Many of these manufacturers have executed or are in the process of executing significant expansions at existing sites or at new, greenfield facilities that will bring significant investment into the state as well as an addition to the manufacturing job base at a time of economic uncertainty in many other sectors of the economy.
- Often, the limitation on a manufacturer's ability to expand is driven by its ability to manage the co-products produced as a result of the expansion. These co-products can be utilized as feedstock for on or off site digesters. With manufacturers that own many facilities across different states, the costs of production can be a factor in whether or not product is made in Wisconsin or elsewhere. Anaerobic digesters provide a cost effective solution to this challenge.
- Increased dairy manufacturing plant production capacity means increased demand for milk, resulting in additional dollars and potential expansion opportunities at the farm level in the state, historically one of the largest sectors of the state economy. Increases in farm sizes means additional opportunities for manure based feedstocks to produce energy and solve potential bottlenecks.

The single largest challenge to continued digester development in the State appears to lie at the federal level. The pending expiration of the 30% Section 48 Investment Tax Credit (ITC) for projects which do not "begin construction" before January 1, 2014 would have a significant impact on projects and their ability to get completed. If this credit is allowed to expire, it is expected that very few projects, if any, would likely be economically prudent unless absolutely necessary (e.g. as a result of a regulatory requirement). This is particularly apparent in cases of on farm digesters that are smaller in scale and/or have limited ability to bring in outside substrates for which tipping fees could be charged.

In our analysis we looked at three primary potential scenarios for helping close the potential funding gap if the investment tax credit is allowed to lapse at the federal level. First, if a hypothetical $15 MM project could obtain a loan at an interest rate of 2% with a 15 year term, the project would benefit by $292,573 annually versus the current market for debt for typical projects. In terms of net present value (NPV) or today`s dollars, the gap could be reduced (on an NPV basis) by *$2.5 million assuming* an 8 percent discount rate over the project life of 20 years. Second, if the project, with $100,000 of annual property tax, did not have to bear this burden, nearly *$1 million* of this hypothetical gap (on an NPV basis) could be filled. Finally, we evaluated the scenario of a low interest subordinated, interest only loan with a balloon of the loan principal due at the end of a 10 year term. Assuming this loan is equal to the amount of a $4.5 million "gap" in project funding, the net benefit on an NPV basis would be in the range of *$1.8 million*.

TABLE 1

Potential impacts of digester project financial variable adjustments			
		Net Present Value	Annually
Base case	"Gap"	$4,500,658	$525,810
Lower interest rate on senior debt	Benefit	$2,504,272	$292,573
Property tax exemption	Benefit	$981,815	$100,000
Interest-only sub-debt with balloon	Benefit	$1,811,988	$ 270,040
Total benefit		$5,298,075	$662,613

In addition, the continued rising cost of diesel fuel, along with emerging proposed amendments to the Renewable Fuels Standard 2 supporting “advanced biofuel”, could also result in an economic model for biogas as a transportation fuel, specifically in captive public or private fleets, that may be worth exploring further. This particularly becomes important if incentives based on electrical production (at the Federal Level) are allowed to lapse.

Overview of analysis

Baker Tilly Virchow Krause, LLP (Baker Tilly) was engaged by the Wisconsin State Energy Office (SEO) to analyze biogas to electricity project opportunities in the State of Wisconsin, stemming from anaerobic digestion activities. This analysis specifically builds upon the economic model toolkit Baker Tilly has previously developed with SEO as part of an engagement to review energy applications from agriculture and cheese manufacturing feedstocks, with the intent to quantify the impacts of specific economic drivers and operational characteristics for successful biogas project investments. Prior to review of this document and the associated analysis the reader may consider reviewing this aforementioned report "Energy Applications from Agriculture and Cheese Manufacturing Feedstocks"[1].

This analysis has been framed to assist SEO to better understand specific risks and opportunities related to the economics of developing biogas production projects, including quantitative backing of such insights. Baker Tilly's intention is that this work product will assist SEO make informed decisions on Wisconsin biogas development initiatives, including engagement in potential policy discussion, industry education and stakeholder engagement.

In general, the project approach was derived from Baker Tilly's in-depth knowledge of biogas projects and the general energy landscape at the Federal and State level. Based on running numerous economic modeling scenarios, we have found that the general project type that appears to be most economical would be one that:

- Has a project size that can take advantage of economies of scale, generally projects above $10 million seem fit this category.
- Can take advantage of the federal investment tax credit.
- Can utilize other credits/incentives which are not entitlements, e.g. New Market Tax Credits, WI Focus on Energy or USDA grants, etc.
- Can charge a fee for waste from third parties who see the facility as an avoided cost of land application solution.
- Can sell waste heat generated from the engine to an adjacent user.
- Can be permitted as a direct discharge to surface waters or discharge water to a municipal system with an attractive rate structure.

On the revenue side, the largest drivers of sensitivity of the economics generally appear to be the tipping fee amount received by a project. Upward adjustments in the price received for power, in most cases, would need to be significant for projects to become economically viable in light of other factors. On the expense side, the single largest variable appears to be the cost of capital, specifically senior debt interest rate. Typical lenders on digester projects may charge anywhere from 7-9% interest for projects that are of a non recourse basis. Additional credit support which would lower these interest rates could have a positive impact on economics projects going forward, and on debt liquidity, as well as potentially allow for more lenders to get involved in borrowing into the space. Property tax is also a variable expense that, by lower or eliminating altogether, could positively impact projects to the point of being feasible.

[1] http://www.bakertilly.com/biogas-energy-digester (August 2012)

While these considerations are incredibly important, the single largest challenge to continued digester development in the State appears to lies at the federal level. The pending expiration of the 30% Investment Tax Credit (ITC) for projects which do not “begin construction” before January 1, 2014 would have a significant impact on projects and their ability to get completed. If this program is allowed to expire, only the best projects with characteristics described above (less the ITC) would likely be economically prudent. The continued rising cost of diesel fuel, along with emerging proposed amendments to the Renewable Fuels Standard 2 supporting “advanced biofuel”, could also result in an economic model for biogas as a transportation fuel, specifically in captive public or private fleets, that is worth exploring further. This particularly becomes important if incentives based on electrical production (at the Federal Level) are allowed to lapse. Additional revenue sources in the form of nutrient recovery are possible as phosphorus and nitrogen stripping technologies are likely to continue to evolve and become more cost effective.

Incentive overview and update

The prior study performed for the Wisconsin SEO by Baker Tilly outlined in detail an overview of financial incentives potentially available to biogas projects. Here we will briefly refresh the current key incentives and provide any updates since the prior report was published.

Production tax credit (PTC)

Originally established by the 1992 Energy Policy Act, the PTC provides tax credits for each megawatt hour (MWh) of electricity a qualifying project generates. The credit applies to the first ten years of the projects life, and adjusts with inflation. The value of the credit today is approximately $11/MWh for typical anaerobic digester projects that produce electricity.

Investment tax credit (ITC)

The ITC is equal to a percentage of the project's qualified capital expenditure and is not linked to production. For most anaerobic digester projects, the ITC is set at 30% of qualified capital expenditures. Generally speaking, for digester projects the ITC is more valuable than the PTC given the large capital outlay in comparison to the energy produced.

As part of the *American Taxpayer Relief Act of 2012*, important modifications to the way the PTC and ITC are treated in terms of eligibility were introduced. Rather than prior law which required facilities to be "placed in service by certain dates", the new legislation requires that certain "begin construction" requirements be met by December 31, 2013. This gives project developers significant additional flexibility in placing projects in service, so long as they meet the begin construction requirements. On April 15, 2013, the Internal Revenue Service (IRS) provided additional guidance, (IRS Notice 2013-29), relative to the "begun construction" requirement for facilities producing electricity from wind, biomass, landfill gas, municipal solid waste and certain other qualified energy sources to qualify for the Production Tax Credit (PTC) and Investment Tax Credit (ITC). The IRS requirement is similar to the eligibility requirements that were relevant under the Treasury 1603 cash grant program. Two methods may be used by taxpayers to establish that construction has begun prior to January 1, 2014: starting physical work of a significant nature OR satisfying a 5% safe harbor test. One significant change is that the IRS requirement for 5% safe harbor now includes a stipulation that the taxpayer make continuous efforts to advance towards completion of the facility after making the initial safe harbor spend prior to January 1, 2014.

Physical work

The taxpayer will satisfy the begun construction requirement if "physical work of a significant nature" has started on the facility. Both on-site and off-site work (performed either by the taxpayer or by another person under a binding written contract) may be taken into account for purposes of demonstrating that physical work of a significant nature has been done. Certain preliminary activities are excluded, as is off-site work to produce property that is either in existing inventory or is normally held in inventory. In addition, the project must maintain a "continuous program of construction". Certain disruptions (including financing delays) that are beyond the taxpayer's control are disregarded.

5% safe harbor

Another way the begun construction requirement can be satisfied is if the taxpayer pays or incurs 5% of the total eligible project costs, and thereafter the taxpayer makes continuous efforts to advance towards completion of the facility. Whether a taxpayer meets the continuous efforts requirement depends on the facts and circumstances, including but not limited to, paying or incurring additional amounts included in the total cost of the facility, entering into binding written contracts for components or future work on construction of the facility, obtaining necessary permits, and performing physical work of a significant nature. Again, certain disruptions that are beyond the taxpayer's control are disregarded – this is identical to the permitted disruptions under the "physical work" test.

Overview of anaerobic digestion from biogas

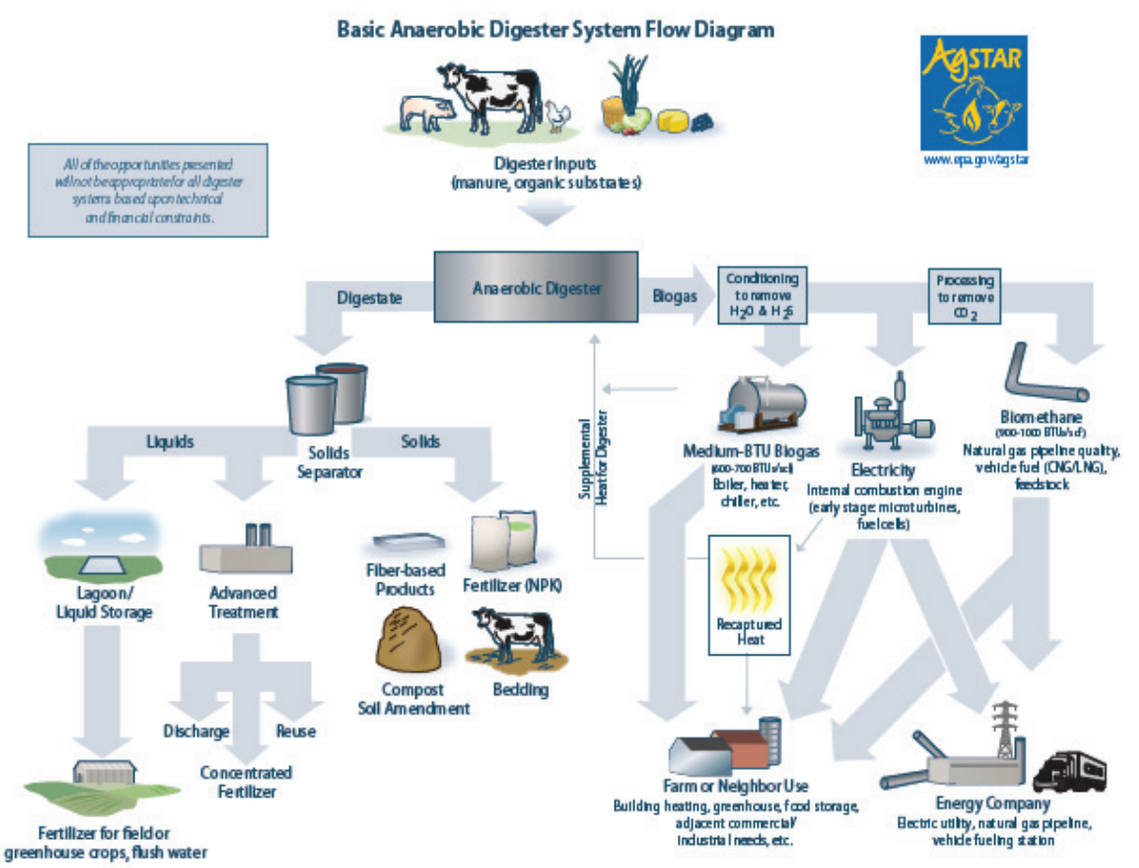
Anaerobic digestion can be classified into two process types: systems which process high strength liquid wastes (HSW) and those which focus on high solids content material (e.g. food waste). In each case, the Chemical Oxygen Demand/Biological Oxygen Demand inherent to either feedstock type ultimately creates the biogas potential. Each individual system then efficiently destructs this COD/BOD to produce biogas gas. For the purpose of this report, we have focused on liquid HSW feedstocks. Anaerobic digestion of HSW creates biogas, which contains around 60 percent methane, with a corresponding heating value of approximately 600 Btu / cu ft. Natural gas by comparison will have a heating value of approximately 1000 Btu/ cu ft. The biogas outputs of this quality, stemming from anaerobic digestion processes, can be utilized in a variety of ways depending on the ultimate need of the producer or relative market demand for a particular biogas end product.

To gain a deeper understanding of the basic parameters of a biogas to energy project, we start as you would in evaluating any proposed energy infrastructure project, with a view to the capital, revenue, and operating cost considerations.

Digester capital budget considerations

The capital budget of a biogas project can be broken up into two primary categories, “hard” and “soft” costs. Within each of these categories there are numerous line items that may vary in specificity from one project to the next depending upon the design parameters, but in a general sense, are accommodated for in most projects. Graphically, the following basic flow diagram from AgStar provides an overview of the “hard” costs of a typical digester, components of which may vary depending upon project specifics.

FIGURE 1



"Soft" costs of anaerobic digester projects may include, but may not be limited to the following; working capital, insurance, capital reserves, financing/legal fees, permitting and other categories that don't pertain to the assets being installed or the land leased or purchased by the project.

Typical agricultural and industrial biogas projects

Based on a number of industry sources, we have tried to make an attempt to compare the revenue, and where possible, expense profile of small, medium, and large scale digester projects on both an agricultural (e.g. on farm) scale and industrial (e.g. project utilizing feedstocks other than manure) scale.

Anaerobic digester projects can derive revenue from a number of fundamentally different sources. These may include; tipping fees, power sales back to a utility or as an offset to existing power costs, renewable energy credits, heat, fertilizer, carbon credits, and nutrient credits (e.g. phosphorus). We have observed in our research, based on multiple sources and conversations with industry stakeholders, that, on average, one might expect distinct revenue profiles for (a) farm based projects which utilize primarily manure as a feedstock and may supplement that with organic industrial wastewater or other feedstocks; and (b) industrial projects which utilize dairy processing plant HSW.

Agricultural digester project revenue split

In February 2013, the Innovation Center for US Dairy, in cooperation with Informa Economics, released a comprehensive report entitled, "National Market Value of Anaerobic Digester Projects".[2] The purpose of that report was to identify the production possibilities and market values of the various products of a mature anaerobic digester industry based on large US dairy farms. This report primarily focused on manure based systems, however also noted an immense opportunity for monetizing organic substrates, should a digester have the ability to accept organic waste which would otherwise be subject to land application or landfill disposal.

Within the Innovation Center for US Dairy report, an analysis was made specific to a number of key dairy states, including Wisconsin, on the theoretical value of certain products from digester products. The analysis was done under a "low", "mid", and "high" valuation scenario to show the revenue potential for WI dairy digesters in a fully developed market place. The study results are summarized below:

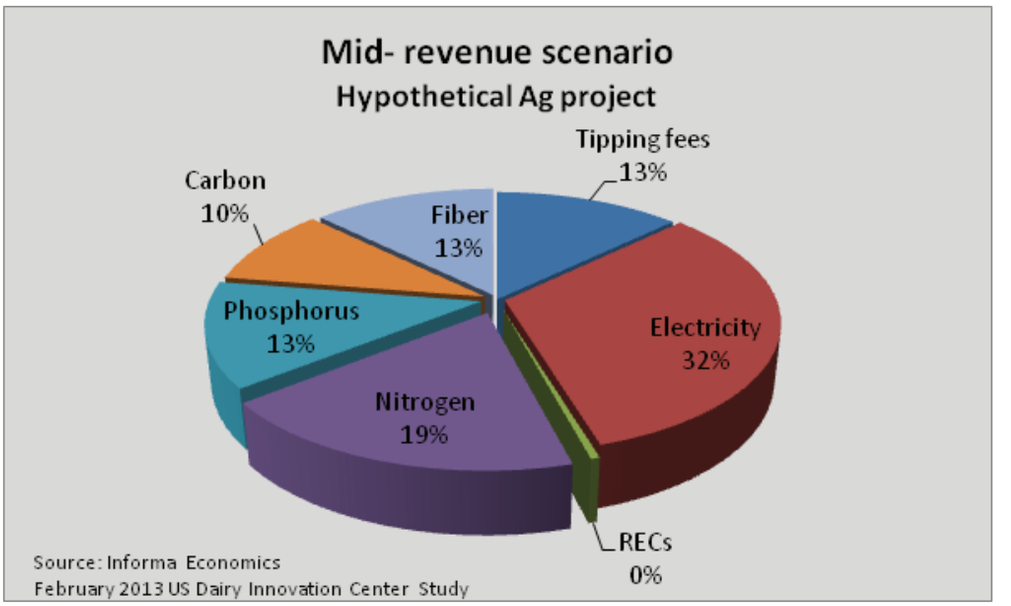
TABLE 2

Innovation Center for US Dairy Valuation Analysis			
Scenario	**Low**	**Mid**	**High**
Tipping fees ($/year)	6,311,136	13,593,216	15,535,104
Electricity ($/year)	13,989,650	34,228,010	51,342,015
RECs	233,161	466,322	1,398,965
Nitrogen	13,090,521	19,635,978	39,271,956
Phosphorus	6,926,604	13,853,208	17,316,510
Carbon	1,029,052	10,290,523	25,726,307
Fiber	11,512,633	13,432,508	14,736,170

[2]Innovation Center for US Dairy, in cooperation with Informa Economics "National Market Value of Anaerobic Digester Projects" (February 2013)

The following graph shows estimated project revenues for an agricultural digester project where electricity sales represent the biggest portion of the revenues. The estimates are based on the Innovation Center for the U.S Dairy`s report published in February 2013, which used AgSTAR`s data base. The estimated revenue mix may be based on what is expected to an average WI CAFO operation of 500 dairy cows or larger, which would utilize a mixed plug flow or a complete mix digester for the biogas generation.

FIGURE 2



While the data accumulated is comprehensive and uses sound assumptions, we would suggest a few comments which could be further emphasized based on our experience in working with anaerobic digester project developers and owner.

As shown in the prior figure, the “tipping fees” represent 13% of the revenue of the “mid” scenario. We agree that tipping fees can be a very valuable part of the revenue mix in making on farm digester projects feasible. In fact, we believe the potential value of tipping fees as part of the overall revenue mix could actually be quite higher than the 13% assumed. However we also are of the view that there is a general lack of sophisticated awareness in the market among owners of on farm systems of the overall market and potential availability of non manure feedstocks, particularly among smaller projects but in some cases larger projects as well. Also, we have generally seen the most successful on farm digester projects as those that are able to efficiently procure and utilize non manure feedstocks as part of the overall feedstock mix, primarily due to the energy or tipping values these substrates can provide to a project.

Another key observation of the revenue mix is the combined amount of 32% of the revenue value placed on nitrogen and phosphorus. As the Dairy Innovation Center report notes “Nutrient stripping technologies currently under development allow for nitrogen and phosphorus be separated into a storable or transportable form. The ability to store and transport nutrients also allows easier compliance with nutrient management regulations for water quality, where nutrient trading programs may develop as an environmental policy implementation tool, it could potentially become an additional source of revenue for dairy operators, but would not seem to be readily available today to facilitate commercial financing.

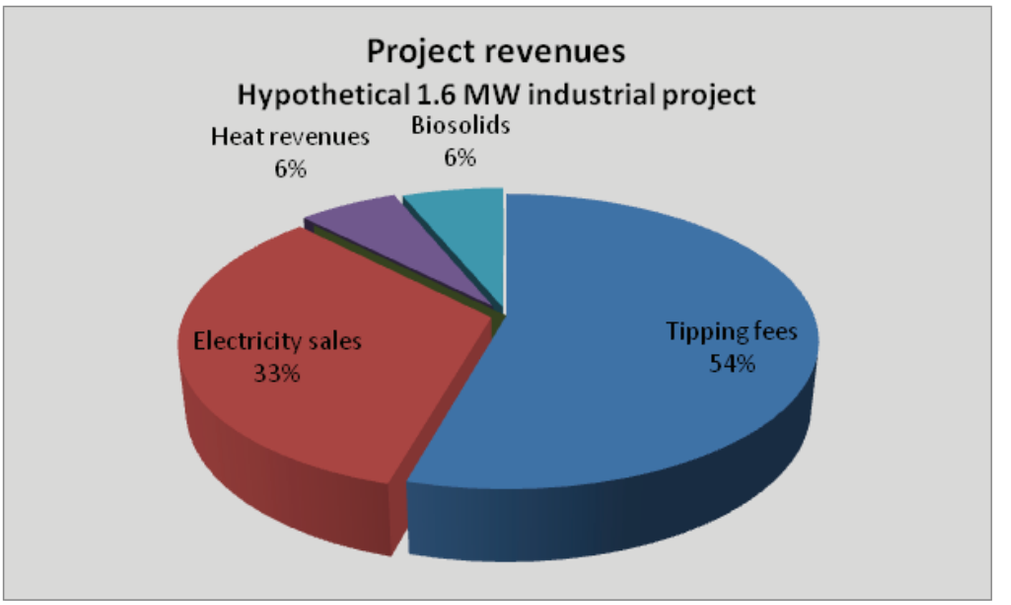
What is not emphasized is the fact that nutrient stripping technologies are relatively new and not yet 100% bankable. Also, there is limited reference to the costs to strip out these nutrients. In other words, even if a reliable nutrient stripping technology is employed at a project, if the costs (capital, energy, chemicals, and logistics) to remove the nutrient are greater than the economic potential, then there is no net benefit to these byproducts for the digester from an economic point of view.

Industrial digester project revenue split

The revenue splits below represent a hypothetical digester project creating 1.6 MW electrical and the primary revenue drivers which could be associated with such a project. The following are the primary drivers that support the revenue assumptions:

- Electricity rate ranges between $6 – 10 per mWh,
- Heat rate for the excess heat ranges from $2 – 4 per MMBtu, and
- Tipping fees range from $5 – 15 per ton based on high strength waste.

FIGURE 3



Potential project revenues

The range estimates are based on average market rates and literature review, are meant to highlight the fact that historically industrial projects solved a disposal need first for HSW. Tipping fee revenues were established based on the estimated volume of HSW which would be required to make 1.6MW of power and the corresponding cost of disposal for this volume if it is sent to a WI municipal sewer or to land application. The resulting graph shows that in the typical industrial digester setting more than the half revenues come from the tipping fees.

Avoided disposal costs (tipping fees)

In review of successful digester projects, a large proportion of them are able to procure feedstocks which have a disposal cost associated with them, and therefore be compensated for receiving

such feedstocks. Typically, these types of feedstocks tend to be coming from industrial operations (e.g. dairy processing facilities) who would otherwise land apply them. What a project may be able to charge in the form of a tipping fee can vary greatly depending on the location of the project. Determining factors of the avoided cost of land disposal may include such factors as the cost of transporting the product to a land application location (e.g. diesel fuel), proximity of the subject digester to other waste processing facilities (either stand alone digester systems or municipal owned waste treatment plants), time of the year, watershed the project is in, whey market dynamics, or location specific other factors. Based on review of land application costs charged by various high strength waste (HSW) haulers in the State, land application costs appear to vary from $0.00 to $0.10/gallon. In specific cases those costs can be even higher. In discussions with waste haulers and dairy processors, most are of the opinion that disposal costs will continue to increase over time due to factors previously listed.

Projects that are setup to procure most or all of their inputs from avoided cost situations tend to be of a larger scale or "industrial" nature. On farm digesters which are typically of a smaller scale have logically been put in place to process primarily, or exclusively, manure based feedstocks. However, there are a number of these types of projects that also supplement their manure feedstock with outside waste for economic reasons. Based on discussions with a number of sources, the authors of this report believe that there may be additional opportunities in the state to improve the economics of so called "on farm" digesters by developing more of an awareness by these facilities of supplemental feedstock availability which can improve not only their revenue from avoided cost collection perspective, but provide an improved biogas profile, and perhaps in some cases provide a partial solution for the primary customer of a dairy farm, the upstream dairy processor.

Power

Most digesters operating in the state today are producing electricity by sending their biogas through an electrical generator, and then either utilizing the power on site, or sending it back onto the electrical grid. This has primarily been a result of the favorable federal tax incentive environment for projects which produce electricity, as well as historical state renewable portfolio standards as well as utility specific tariffs for these types of projects with attractive pricing. In terms of revenue, the price received for power can vary depending upon the location and utility serving (buying power from) the project.

Renewable energy credits (RECs)

Electricity generated from anaerobic digesters also includes a REC component that can be sold with the physical energy, or separate of the energy, depending on the situation. Renewable energy credits allow utilities to comply with state level renewable portfolio standards (RPS). The value of renewable energy credits varies from state to state, as RPS requirements are adjusted or change over time.

> While compliance RECs generally must be sourced from within some geographic region to be eligible for RPS compliance, voluntary RECs can be sourced either regionally or nationally. Most utility green pricing programs or marketers selling bundled electricity and REC products source their products from local or regional resources, with some exceptions. Buyers of nationally sourced voluntary RECs are often large corporations that have facilities in multiple locations across the country. In voluntary markets, RECs from certain regions may sell at a premium if they are competing with RECs used for RPS demand, or are coming from regions with limited renewable resources. For example, from 2007 to December of 2011, western wind RECs sold at higher prices than nationally sourced wind

RECs. Nationally sourced voluntary RECs are typically derived from the most cost-effective renewable resources nationally.[3]

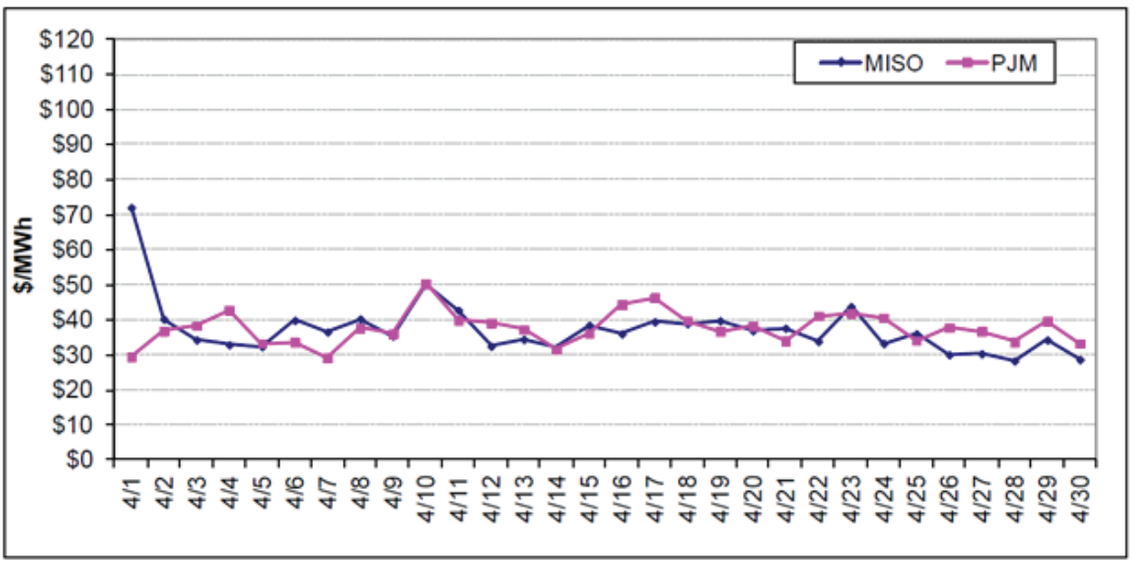
Additionally states have varying allowances for renewable energy credits to be procured by utilities from "in state" or "out of state" resources. Wisconsin has a statewide RPS target of 10% by 2015, and most utilities are on track to meet this target. Thus the current value of renewable energy credits generated by eligible projects in the state of Wisconsin is minimal relative to values in earlier years or in other states with more recently developed RPS standards or more aggressive targets.

Net metering

Generally, net metering limits in Wisconsin can be up to allowed for systems up to 20 kW. Utilities' net-metering tariffs contain some variations. In general, customer net excess generation (NEG) is generally credited at the utility's retail rate for renewables, and at the utility's avoided-cost rate for non-renewables. More about net metering for individual utilities in Wisconsin can be found in our previous report, under the section "Wisconsin net metering and advanced renewable energy tariffs."[4]

Our analysis assumes that the balanced electricity rate for the hypothetical case is 8 cents per kWh. However, if the net metering regulations and current electricity market conditions are not favorable for digester project, the electricity rates could potentially drop between $30 and $40 per MWh for electrical generation over 20kW at an industrial site, based on the last 13 month average. These current low buy-back electricity rates would more negatively impact agricultural digesters since the share of revenues that comes from the electricity sales is significantly higher compared to the industrial digester projects.

FIGURE 4



Renewable natural gas

Biogas can also be utilized as a displacement for natural gas in applications either on site or off site. In Wisconsin most often this application is done on site in situations where the biogas source is adjacent to a larger energy user (e.g. cheese processing facility or public wastewater treatment plant), where the gas can be sent back to a boiler as a fuel source. However, due to the existing federal

3 http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5
4 http://www.bakertilly.com/biogas-energy-digester

incentives for electrical production from biogas (30% investment tax credit), a boiler only heat offset project have become less attractive in the current climate. This may change if federal incentives for the ITC are allowed to lapse and or the renewable natural gas markets develop further.

Heat

An often overlooked value component of digester projects is the “waste” heat generated as a byproduct from the engines, akin to a combined heat and power project scenario more often seen at large natural gas plants. This waste heat recovery off the generator (s) of a project can provide a valuable resource for heating, cooling and process applications. However, this is not always available to digester projects given (a) economies of scale of digester projects can limit the impact (value) of the waste heat and (b) a “customer” or end user of the waste heat needs to be geographically very close to the source of the heat. Larger scale digesters adjacent to dairy processing facilities are often the best candidates for this type of situation where significant value may be able to be harvested by the digester project.

Fertilizer

Much discussion and debate continues to occur regarding the inherent value of the nitrogen (N), phosphorus (P), and potassium (K) contained within the liquid or solid fractions of anaerobic digester co-products. While there are known nutrient “stripping” technologies available for N and P, the author is not aware of digester projects where these technologies have been successfully deployed from both a technical and economic perspective. Questions remain regarding these technologies capital costs, operation costs, regulatory implications of deployment, and market acceptance of the corresponding end products for potential sale. As a result of this current market reality our internal analysis places minimal value on the sale of fertilizer or “biosolids” from digester facilities based on prior experience with numerous projects regarding this aspect.

Carbon credits

In the United States, only voluntary markets for greenhouse gas (GHG) emission reduction or sequestration have existed. The estimate of $10 per metric ton (MT) of carbon equivalent gas has been given by numerous studies as a long term equilibrium price of GHG offsets. The long term view of the value of carbon varies significantly. Most anaerobic digesters which are utilizing cow manure as a feedstock, for example, are deriving, or anticipate deriving some value from carbon credit sales. The carbon credit revenue to date has not been a driving economic factor for proceeding with installation of a project (although long term, may be a considering factor). nother important factor to note is that current protocols that allow for monetization of carbon benefits for feedstocks other than manure are not in place. Therefore a digester project that is processing dairy plant waste would not be in a position to harvest value from GHG destruction as a result of the project, as of today. This could change in the future as carbon credit protocols are further developed.

Phosphorus credits

On July 25, 2012 the United States Environmental Protection Agency (EPA) approved the Wisconsin Department of Natural Resources (DNR) proposed rules regarding the discharge of phosphorus into Wisconsin waterways. These rules impact publicly owned treatment works, private (industrial) treatment facilities, and CAFOs that discharge manure or process wastewater through alternative treatment facilities. These facilities have opportunities to comply with the new regulations over a

period of years using options such as treatment facility improvements, water quality trading, adaptive management, or obtaining a variance.

As a result there may be the potential opportunity for a phosphorus trading mechanism to be established that could potentially provide additional value to those digesters which would employ phosphorus stripping technology. By subsequently removing the phosphorus from the watershed in which the digester was located, it could be possible to generate "credits" which could be then be sold to facilities that were looking to comply via this trading mechanism.

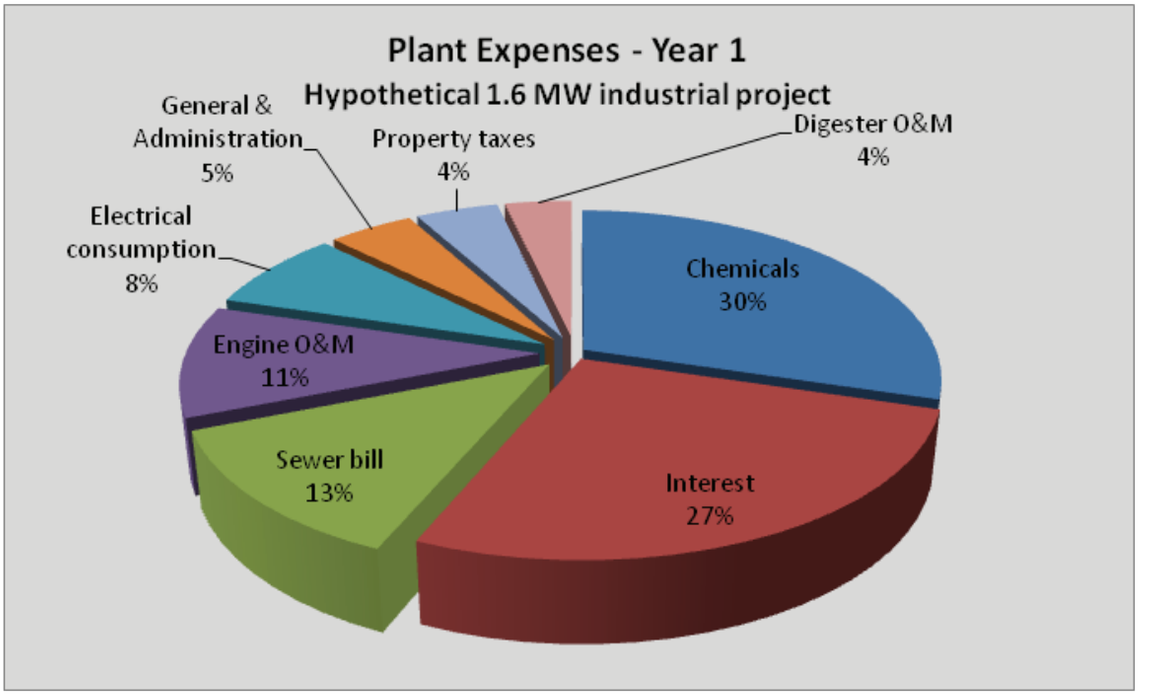
In order to attempt to tangibly quantify the potential opportunity of trading in phosphorus credits, a future study and or review of existing literature may be of value. This may include:

- Evaluate existing proven phosphorus stripping technologies
- Evaluate the cost to add on to existing or new digester
- Evaluate any gaps that exist in the economics which could potentially be filled by the sale of phosphorus credits generated by a typical facility, and at what value those credits would need to be priced
- Evaluate the cost of this option versus current estimates of municipal treatment plant upgrades
- Evaluate options/feasibility for 3rd party financing/ownership of such assets

Hypothetical 1.6 MW industrial anaerobic digester expenses

Equally important in evaluation of the feasibility of anaerobic digester projects are the variables that make up an overall expense profile. Some variables are more constant from project to project, while others can vary dramatically. Below is an estimated summary of the primary expenses area these types of digesters can incur:

FIGURE 5



Likewise, some expense variables can have larger impacts than others on the overall bottom line of a digester project. The following is a further explanation of some of the key expense items which could also be affected by changes in WI policy:

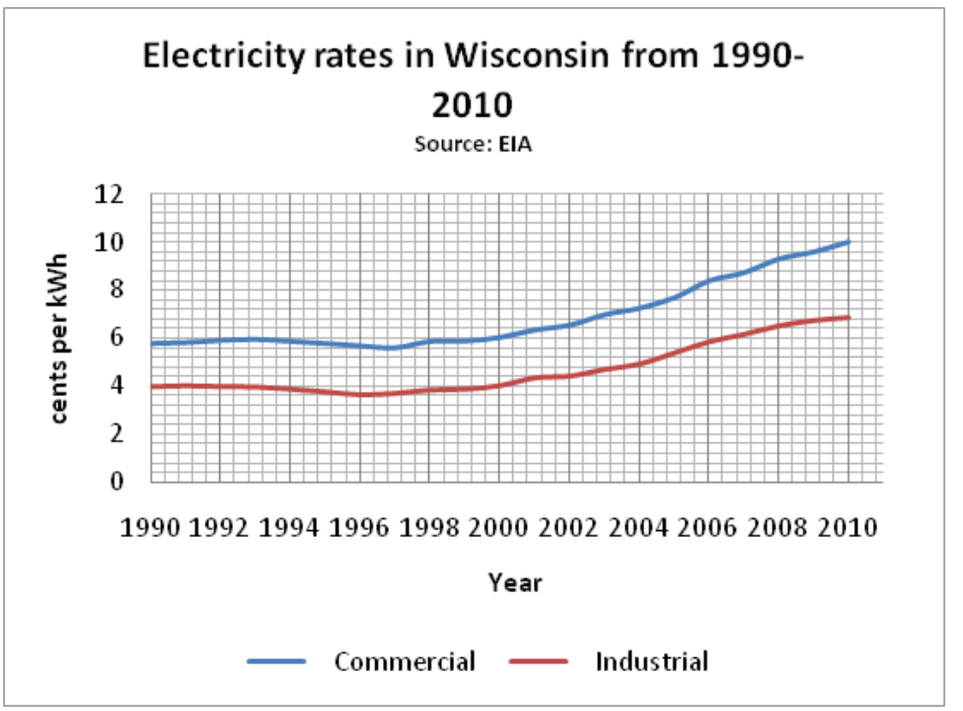
Interest expense (cost of capital)

The overall cost of borrowing capital (in the form of debt) for an anaerobic digester can dramatically impact the economics of a project. While we have observed some projects proceeding without debt financing (e.g. using equity investments along with other funding such as grants), most projects developed by the private sector require some amount and form of limited or non-recourse debt. For repayment, this type of debt relies upon the underlying contracts that a project is a party to, such as power purchase agreements, feedstock supply agreements, and engineering, procurement, and construction (EPC) contracts that provide guarantees as to the performance of the facility. Therefore, non recourse debt is priced higher than traditional debt, which can make the economics of digester projects challenging irrespective of the value of various revenue sources of a project.

Power prices

The Energy Information Administration (EIA) database shows that the historical electricity rates, both commercial and industrial, increased significantly from 1990 to 2010 as shown in the following graph.

FIGURE 6



The most recent data provided on the Wisconsin PSC website indicated that the electricity rate is

12 cents per kWh for small and 10 cents for larger users, respectfully.

Depending upon the size of the digester and technology employed, the cost of power to run the digester can be a significant variable. However, this power can be offset by the digester producing its own power. Further net metering of power can provide additional value if there is an adjacent sink (e.g. farm or cheese processing plant). If we assume a typical farm pays a commercial rate, one can see from the prior graph that a more aggressive net metering approach could potentially benefit on farm digesters versus industrial ones.

Property taxes and sales and use taxes

As outlined in Appendix 2 of the predecessor to this report ("Energy Applications from Agriculture and Cheese Manufacturing Feedstocks"[5]), until recently a number of questions existed regarding tax treatment of anaerobic digesters in the state of Wisconsin, including:

- Would the Wisconsin property tax exemptions available to waste treatment facilities, manufacturers, and farmers apply to an anaerobic digestion system?
- Does the availability of the property tax exemption depend on the owner/operator of the system and/or on what is processed?
- Whether the anaerobic digestion system qualifies for one of the property tax exemptions; is there a corresponding exemption from Wisconsin sales/use taxes?
- Is the sales/use tax exemption dependent upon the property tax exemption?
- Does the availability of the sales/use tax exemption depend on the owner/operator of the system and/or what is processed?
- Are there any other Wisconsin tax issues to consider for an anaerobic digestion system?

Appendix 2 in the prior report went into significant detail around these issues and should be referenced to understand a current project's potential property tax designation. On the property tax side, it has been observed that the challenges have primarily related to 1) variability from local assessor to local assessor on how property tax is treated, 2) the lack of clarity regarding the actual property tax owed until after the property is placed into service. As one can imagine, it can be challenging to explain to lenders or investors that while they should make a loan or investment in a project, the actual annual property tax obligation of a project will not be absolutely known until after the project is complete (after their monetary commitment has been made).

The Wisconsin legislature has addressed this lack of certainty through the amending of existing legislation, which originally gave tax exempt treatment to certain wind and solar property, beginning with property assessed as of January 1, 2014.[6] The statute now includes biogas or synthetic gas energy systems. "Biogas energy system" means:

- equipment which directly converts biomass, as defined under section 45K (c) (3) of the Internal Revenue Code, as interpreted by the Internal Revenue Service, into biogas or synthetic gas;
- equipment which generates electricity, heat, or compressed natural gas exclusively from biogas

5 http://www.bakertilly.com/Waste-to-Energy-Agriculture-Cheese-Production-Feedstocks
6 2013 Wisconsin Act 20 https://docs.legis.wisconsin.gov/2013/related/acts/20/1279/_1

or synthetic gas;

- equipment which is used exclusively for the direct transfer or storage of biomass, biogas, or synthetic gas; and
- any structure used exclusively to shelter or operate such equipment; or
- the portion of any structure used in part to shelter or operate such equipment that is allocable to such use, if all such equipment, and any such structure, is located at the same site, and includes manure, substrate, and other feedstock collection and delivery systems, pumping and processing equipment, gasifiers and digester tanks, biogas and synthetic gas cleaning and compression equipment, fiber separation and drying equipment, and heat recovery equipment, but does not include equipment or components that are present as part of a conventional energy system.

Most of the other expenses related to anaerobic digester systems are more difficult to compare and/or affect by any chances in policy as they are either fixed (e.g. labor expenses) or vary from technology to technology (e.g. chemical costs, energy costs, biosolids removal costs, etc.).

Summary observations

Agricultural projects

- Primary driver of economics is electricity sale price. Projects developed in the state to date have relied heavily on various utility tariff programs.
- Those agricultural projects that have taken advantage of local sources of supplemental waste and have been able to charge fees for processing the waste have generally been the most economical projects.
- The potential value of stripping out nitrogen and phosphorus will remain just that (potential) until stripping technologies can be developed that are proven and economical from an operational standpoint.
- Economies of scale challenge the economic viability of agricultural projects as most of these projects in the state are relatively small (<$5 MM).

Industrial projects

- While benefitting from electrical tariff programs similar to agricultural projects, industrial projects primary revenue driver is charging tipping fees for processing higher organic strength waste.
- Economies of scale tend to favor industrial projects.
- There is generally less nutrient value in the biosolids produced by industrial projects versus agricultural projects.
- Depending on the location of the project and specific design, industrial projects can be viewed as an asset which alleviates the burden of the local POTW, or competition to the local POTW. Significant opportunity may exist for cooperation between privately and publicly owned biogas plants.

Both agricultural and industrial projects

- Projects are all heavily dependent on the Federal Section 45 Production Tax Credit or the Section 48 30% investment tax credit.
- Should these Federal incentives expire, the economic gap created for financing a typical project in the state could be challenging.
- Additional analysis later in the report will address tactical solutions for how the state of WI can help bridge this gap.

Filling the potential gap

The largest potential challenge to continued digester development in the State lies at the federal level. The pending expiration of the thirty percent ITC for projects which do not "begin construction" before January 1, 2014 would have a significant impact on projects and their ability to get completed. Should this scenario unfold, potential tools to replace this 30% gap in project funding could be evaluated at the federal or state level.

Federal Programs to potentially fill gaps in projects

USDA REAP Program

This program is made available to Agricultural Producers (individual or entity directly engaged in the production of agricultural products that gets 50 percent plus of their gross income from agricultural production) or Small Rural Businesses (must meet SBA definition of small business) that are private entities, sole proprietorships, partnerships, corporations, or cooperatives. The applicant must also be located in a rural area that has a population of less than 50,000. These grants can be for up to 25% of the project cost, with a maximum grant award of $500,000[7]. The fact that the REAP program is extremely competitive in combination of the maximum grant amount limitations likely minimizes the overall impact REAP can have on filling any future potential funding gaps in digester projects.

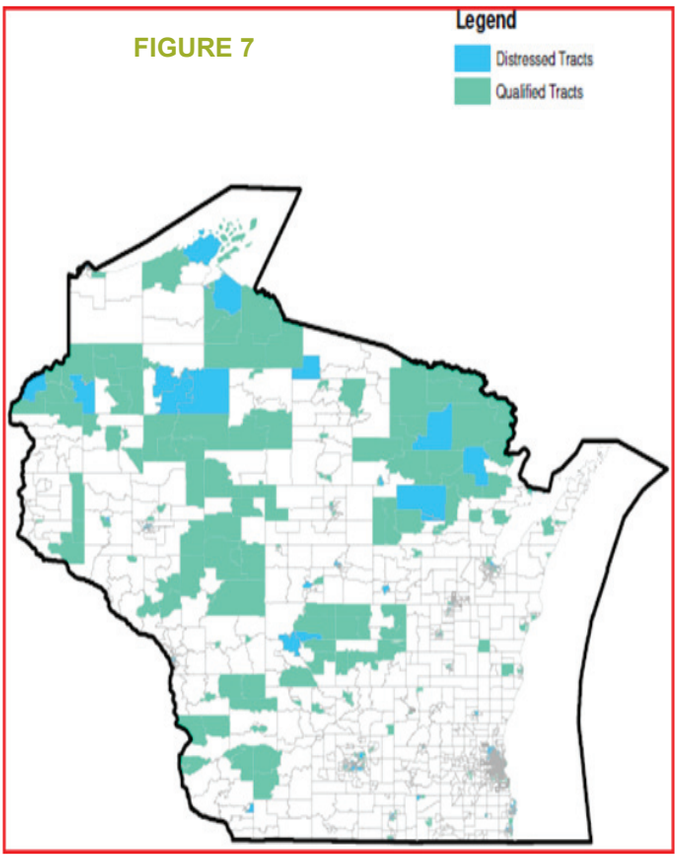
Federal New Markets Tax Credit Program

The New Markets Tax Credit (NMTC) was enacted by the Community Renewal Tax Relief Act of 2000 (P.L. 106-554, 113 Stat. 2763) to provide an incentive to stimulate investment in low-income communities. Significant detail around the New Markets Tax Credit program is provided in the prior SEO report developed by SEO and Baker Tilly (August 2012). The NMTC program can provide up to 20% of a projects capital need. However, when considering the NMTC program as a potential funding tool for digester development, one must keep in mind a number of factors that can determine a project's likelihood of getting an allocation of NMTC.

- Eligibility of location and level of economic distress of the project location
- Direct, indirect, and induced jobs created by the project
- Availability of allocation in the marketplace

To the right is a basic map to show qualifying NMTC areas in the state of Wisconsin. It cannot be overemphasized that the NMTC program is

FIGURE 7



7 http://www.rurdev.usda.gov/BCP_ReapResEei.html

NOT an entitlement program and is extremely competitive, therefore reliance on NMTC to fill funding gaps for future biogas projects should be minimal.

Concepts to potentially fill gaps

For discussion purposes, let's take a generic $15 million industrial digester project. The sources of funds for the project might look something similar to the following:

TABLE 3

Example Sources of Funds for a $15 MM Project		
Step 1 - Sources and uses of funds	**% of Total**	**Amount**
Sourcesof funds		
Grant or other upfront incentives	30.0%	4,500,658
NMTC	0.0%	-
Other	0.0%	-
Equity	*20.0%*	3,000,439
Term debt	50.0%	7,501,097
Total sources	***100.0%***	**15,002,195**

We assume the "grant or other upfront incentive" is the equivalent of the 30% investment tax credit and that it can be utilized by the project in the year it is placed in service. Assuming that the ITC will not be extended after 2013 and other similar incentives(s) will not be enacted, therefore the "ideal" project would face a financial gap of approximately $4.5 million, which is approximately 30% of the initial costs.

If the project had to borrow money at the same loan terms (8 percent interest rate at 15 years), as for the senior portion of debt, the project would need to support approximately $525,000 in additional annual loan repayment.

To overcome the gap, the analysis suggests three areas to explore to overcome the gap:

- a publically-backed low interest loan option,
- property tax exemption akin to other renewable energy property in the state,
- and/or an interest only balloon financing options with revolving loan funds.

First, a low interest financing option, like bonds used in a municipal setting, for the senior debt of $7.5 million would decrease the yearly debt payments and or allow for additional debt to be obtained given the better Debt Service Coverage Ratio (DSCR) created. DSCR is generally defined as the ratio of unlevered cash flow available for debt servicing to interest and principal payments. The higher this ratio is, the easier it is to obtain a loan, or the more money you are able to borrow as a percentage of the overall project budget.

Let's assume a lender requires a minimum of approximately 1.3X DSCR as part of its underwriting criteria. From the sensitivity table below, we can see that at 8% interest and 50% debt, the project can

meet that requirement. If the interest on that same loan is lowered to 2%, the project can cover the same amount of debt at 1.9X coverage, or perhaps the lender will allow the borrower to obtain closer to 80% debt as a percentage of the overall project cost at this rate since at this amount the DSCR is close to 1.3X, thus filling our hypothetical 30% gap. Above is a sensitivity table showing the affect of interest rate on the ability to support more debt in a given project.

TABLE 4

Sensitivity Analysis							
Percent of debt increment			10.0%	Interest rate increment			1%
% Debt vs.Interest rate solving for Year 1 Debt Service Coverage Ratio							
	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%
30%	3.49	3.22	2.98	2.76	2.57	2.39	2.23
40%	2.61	2.40	2.22	2.06	1.91	1.78	1.66
50%	2.08	1.91	1.76	1.63	1.51	1.41	1.31
60%	1.72	1.58	1.46	1.35	1.25	1.16	1.08
70%	1.47	1.35	1.24	1.15	1.06	0.98	0.91
80%	1.28	1.17	1.08	1.00	0.92	0.85	0.79
90%	1.13	1.04	0.95	0.88	0.81	0.75	0.69

In our original case with the ITC being still available, the senior debt is based on an 8 percent interest rate and a 15 year term. If the project could obtain a loan at more municipal like interest rate of 2% with a 15 year term, the project would benefit $ $292,573 annually. In terms of net present value or today`s dollars, the gap could be reduced (on an NPV basis) by $2.5 MM assuming an 8 percent discount rate over the project life of 20-years.

The next area of review was on property tax. Our example model assumes a property tax burden to the $15 MM project of $100,000/year. If the project did not have to bear the burden of this tax over its 20 year theoretical life, nearly $1 MM of this hypothetical gap (on an NPV basis) would be able to be filled.

Finally, another potential way to fill part of the theoretical gap would be for a third party to provide a low interest subordinated loan with a balloon of the loan principal due at the end of the term (say 10 years), with interest only being paid during the term. Again, assuming this loan is equal to the amount of our $4.5 MM “gap”, the net benefit on an NPV basis would be in the range of $1.8 MM, assuming the owners fund the repayment of the loan principal with cash by way of refinance at the end of the 10 year term.

TABLE 5

Potential Impacts of Digester Financial Variable Adjustments			
		Net Present Value	Annually
Base case	"Gap"	$4,500,658	$525,810
Lower interest rate on senior debt	Benefit	$2,504,272	$292,573
Property tax exemption	Benefit	$981,815	$100,000
Interest-only sub-debt with balloon	Benefit	$1,811,988	$ 270,040
Total benefit		$5,298,075	$662,613

[4]http://www.bakertilly.com/biogas-energy-economic-tool

Above is a summary of the individual total affect that using three scenarios described above could potentially alleviate a gap in funding created by the potential expiry of the Federal ITC on a hypothetical $15 million digester project.

Additional sensitivity analysis

The sensitivity analysis for an "ideal" industrial case project size of 1.6MW is based on the data found in the literature review and the internal sources. The initial project costs are estimated to be $15 million, the plant annual expenses are estimated to be $1.7 million, and the project life is assumed to be 20 years. In addition, the case assumes the following financial parameters:

TABLE 6

Base Financial Case Assumptions	
Influent tipping fee ($/ton)	10.00
Blended electricity rate ($/kWh)	0.08
Electricity pricing escalation rate (%)	2.5%
Heat recovery rate ($/MMBtu)	3.00
Heat pricing escalation rate (%)	3.0%
Inflation (%)	3.0%
Debt term (years)	15
Interest rate (%)	8.0%
Required rate of return rate (%)	15.0%

For example purposes and using the mix of capital, revenue, and operating expense assumptions described above, a basic sensitivity analysis around a certain revenue variables which can impact the economics of projects was performed. In this case we used an "average" industrial project with the idea of focusing on the change in sensitivity of the values related to interest rate of the senior debt of a project and a reduction in the property tax on an anaerobic digestion project.

The sensitivity analysis is based on levered pre-tax Internal Rate of Return (IRR) calculated based on the equity portion of the project (outflow) and the stream of future cash flow after principal and interest are paid off. No tax estimates are included in the analysis. The green-red coloring is based on the required rate of return of 15 percent. In the tables below the red color exhibits scenarios where projects would not meet the required rate of return and the green color indicates scenarios where the project would meet the required rate of return.

Users of the Baker Tilly economic toolkit can also modify numerous variables within Microsoft Excel to see results under different scenarios. The results of these specific sensitivity analyses are found in the following tables[4]:

TABLE 7

Sensitivity Analysis							
Initial cost increment ($)			1,000,000	Power price increment ($/kWh)			0.01
Initial Costs vs. Power Price solving for IRR							
	12,002,195	13,002,195	14,002,195	15,002,195	16,002,195	17,002,195	18,002,195
0.050	11.8%	9.6%	7.6%	5.9%	4.4%	3.0%	1.8%
0.060	16.1%	13.5%	11.3%	9.4%	7.7%	6.1%	4.8%
0.070	20.4%	17.4%	14.9%	12.8%	10.9%	9.2%	7.7%
0.080	24.8%	21.4%	18.6%	16.2%	14.1%	12.2%	10.5%
0.090	29.2%	25.5%	22.3%	19.6%	17.3%	15.2%	13.4%
0.100	33.8%	29.7%	26.2%	23.1%	20.5%	18.3%	16.3%
0.110	38.4%	33.9%	30.0%	26.7%	23.9%	21.4%	19.2%

TABLE 8

Sensitivity Analysis							
Initial cost increment ($)			1,000,000	Tipping fee increment ($/ton)			0.50
Initial Costs vs.Tipping fee solving for levered pre-tax IRR							
	12,002,195	13,002,195	14,002,195	15,002,195	16,002,195	17,002,195	18,002,195
8.50	16.0%	13.4%	11.2%	9.2%	7.5%	6.0%	4.6%
9.00	18.9%	16.1%	13.6%	11.6%	9.7%	8.1%	6.6%
9.50	21.8%	18.7%	16.1%	13.9%	11.9%	10.2%	8.6%
10.00	24.8%	21.4%	18.6%	16.2%	14.1%	12.2%	10.5%
10.50	27.7%	24.1%	21.1%	18.5%	16.2%	14.2%	12.5%
11.00	30.7%	26.9%	23.6%	20.8%	18.4%	16.3%	14.4%
11.50	33.8%	29.7%	26.2%	23.2%	20.6%	18.3%	16.3%

One can deduce from the tables that significant changes (from a utilities perspective) would be required to increase the power price to a point where it would have a marked impact on overall project returns. Conversely, small changes in tipping fee costs (on a per ton basis) can have a substantial impact on the economics of a project, particularly those that are sized to handle larger quantities of material. As costs of land application continue to rise for liquid waste producers due to increasing regulation and costs of hauling (primarily due to farther hauls to get to rural areas, and increasing costs of diesel fuel), this variable should continue to be a key driver of biogas projects irrespective policy movements.

Sensitivity analysis-expenses

Example sensitivity was also performed around two expense variables in typical biogas projects – interest expense and property tax expense. The sensitivity tables are represented as follows:

TABLE 9

Sensitivity Analysis							
Initial cost increment ($)			1,000,000	Interest Rate Increment			1%
Initial Costs vs. Interest rate solving for levered pre-tax IRR							
	12,002,195	13,002,195	14,002,195	15,002,195	16,002,195	17,002,195	18,002,195
5%	29.0%	25.5%	22.6%	20.1%	17.8%	15.9%	14.2%
6%	27.6%	24.2%	21.3%	18.8%	16.6%	14.7%	12.9%
7%	26.2%	22.8%	19.9%	17.5%	15.3%	13.4%	11.7%
8%	24.8%	21.4%	18.6%	16.2%	14.1%	12.2%	10.5%
9%	23.3%	20.1%	17.3%	14.9%	12.8%	11.0%	9.4%
10%	21.9%	18.7%	16.0%	13.6%	11.6%	9.8%	8.2%
11%	20.5%	17.3%	14.7%	12.4%	10.4%	8.6%	7.1%

TABLE 10

Sensitivity Analysis							
Initial cost increment ($)			1,000,000	Property Tax Increment			34,333
Initial Costs vs. Property tax solving for levered pre-tax IRR							
	12,002,195	13,002,195	14,002,195	15,002,195	16,002,195	17,002,195	18,002,195
0	25.5%	22.0%	19.1%	16.6%	14.4%	12.5%	10.8%
34,333	25.2%	21.8%	18.9%	16.4%	14.3%	12.4%	10.7%
68,667	25.0%	21.6%	18.8%	16.3%	14.2%	12.3%	10.6%
103,000	24.7%	21.4%	18.6%	16.2%	14.1%	12.2%	10.5%
137,333	24.5%	21.2%	18.4%	16.0%	14.0%	12.1%	10.5%
171,667	24.3%	21.0%	18.3%	15.9%	13.9%	12.0%	10.4%
206,000	24.1%	20.9%	18.1%	15.8%	13.7%	11.9%	10.3%

As you can see from the sensitivity tables, impacts, particularly regarding interest rate can have significant effects on the viability of digester projects. Property tax reductions can have less of an overall impact, but some impact nonetheless. Ways to reduce overall interest rates on projects in the form of credit support may want to be explored as an option in light of the benefits digester projects can bring to the public and private sectors.

Biogas as a transportation fuel

While somewhat outside of the overall scope of this study, we have provided brief commentary on a continually emerging opportunity related to biogas as a transportation fuel, specifically for truck fleets. With the pending expiry of the production and investment tax credit for those projects that don't meet the "begin construction" requirements as previously discussed, a 30% (in the case of the ITC) "hole" in the project capital budget would need to be replaced. It is safe to assume that with the expiry of this credit, most anaerobic digester projects developed historically, relying on power sales as a primary source of revenue would not be economically feasible. While the PTC and ITC have been extended multiple times in recent years, the prospect that they may not be extended, or that they could be significantly modified, needs to be taken into consideration when looking to the future of biogas project development.

If the PTC and ITC are allowed to lapse, utilization of biogas as a transportation fuel is now put on a level playing field from a federal incentive perspective. The following table represents the inherent value of biogas at various diesel fuel price points.

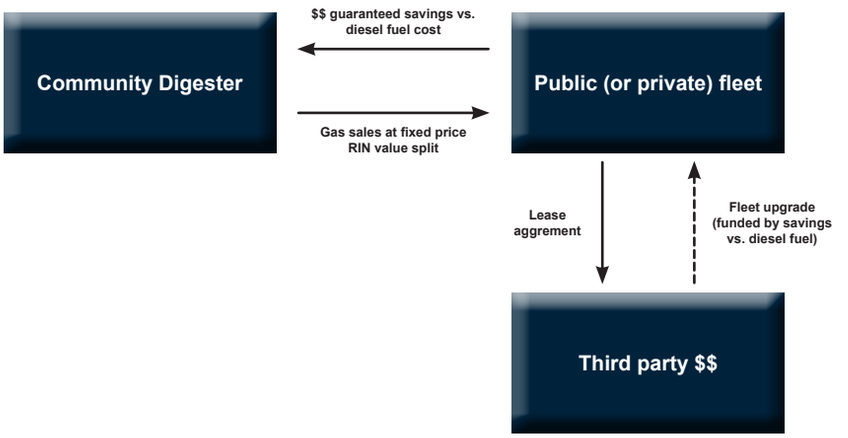
TABLE 11

Energy source valuation - Comparison			
Energy source	*Diesel #2*	*Bio-methane*	*Electricity*
Btu per unit	138,690	1,025	3,412
Value units	**($/gallon)**	**($/MMBtu)**	**($/kWh)**
Theoretical values	**$ 2.50**	**$ 18.03**	**$ 0.06**
	$ 3.00	**$ 21.63**	**$ 0.07**
	$ 3.50	**$ 25.24**	**$ 0.09**
	$ 4.00	**$ 28.84**	**$ 0.10**
	$ 4.50	**$ 32.45**	**$ 0.11**
	$ 5.00	**$ 36.05**	**$ 0.12**

One can see that at today's diesel fuel prices, the "value" (in comparison to diesel fuel) of biogas used as a transportation fuel or to generate electricity is significant, in many cases enough to make a project feasible without the federal PTC or ITC.

Of course, a utility producing power has the option of using the cheapest available energy source (e.g. natural gas) when firing its facilities. Similarly, a truck fleet that has converted to CNG also may purchase CNG fuel using the prevailing natural gas price as an index rather than the "avoided cost" of diesel fuel. However, the exploration of several different business models around bioCNG as a fuel, in our opinion, is worth further exploration. One possible model could be as follows:

FIGURE 8

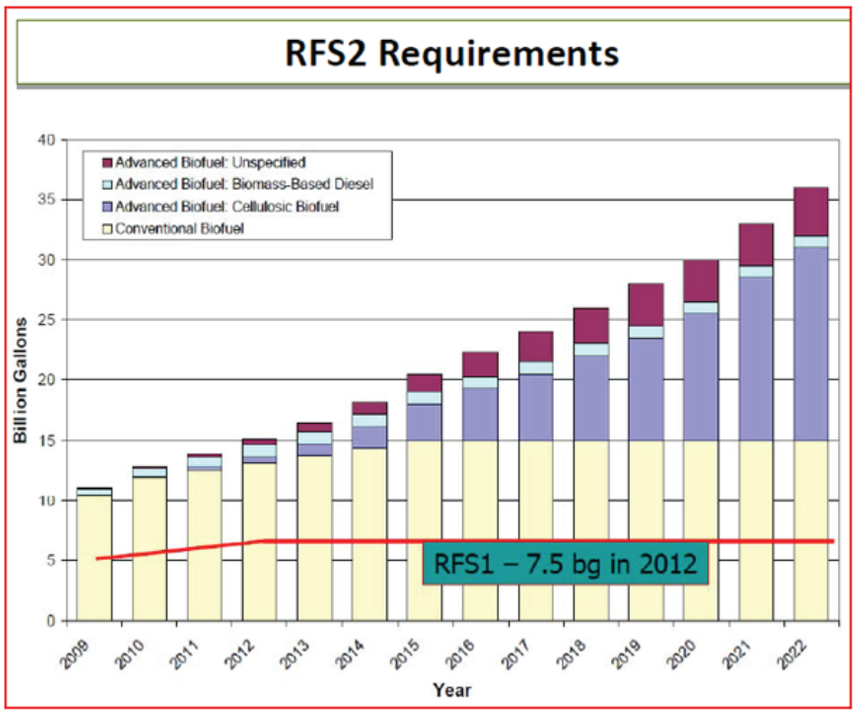


The basic premise of this potential concept would be that in exchange for (a) long term potential savings versus current diesel fuel costs and (b) potentially financing fleet upgrades and or fueling station infrastructure, it may be of interest for municipal or privately owned fleets of various sizes to consider entering into agreements for bioCNG. In this scenario, the value of the Renewable Identification Number (RIN) would also enter the economic equation, in addition to the value of the gas as a pure commodity.

The Federal EPA blending mandate requires the use of renewable fuels in the core US fuel supply as part of the US Renewable Fuel Standard 2 (RFS2). The RFS2 calls for 2.0 Billion gallons of renewable fuel to be produced and blended in the US fuel consumption as of 2012, with this ramping up to 21 Billion gallons of non-corn based ethanol biofuels in 2022.

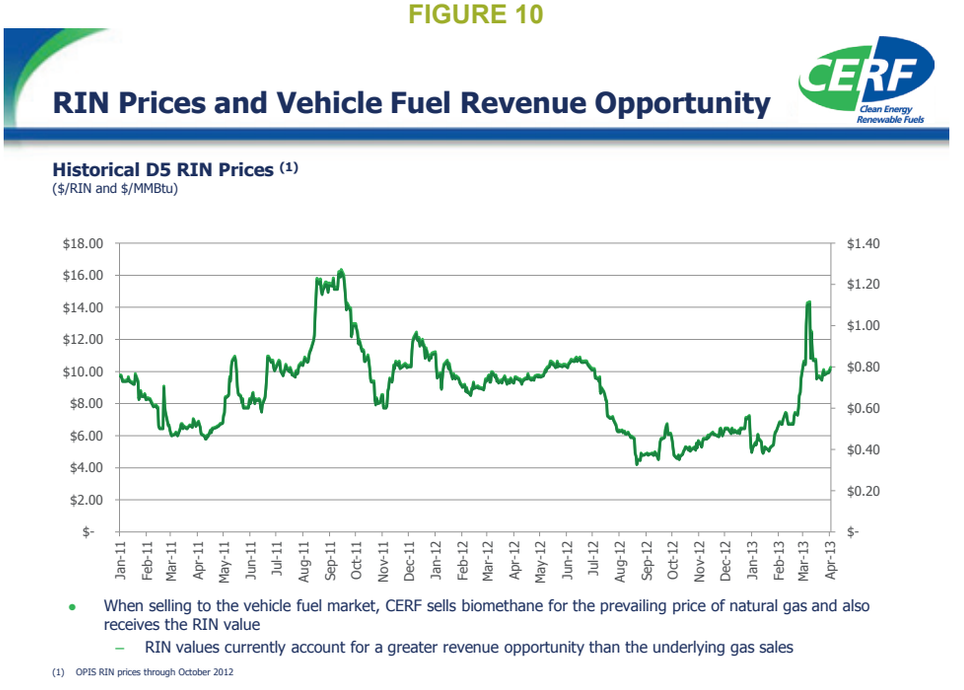
Parties who currently produce traditional petroleum derived fuels will need to produce or procure renewable gallons in their proportion of US production to meet their obligation of the RFS2 blending mandate. When companies do not produce the fuel, they can buy the gallon of fuel from another producer, who is not obligated, and with this purchase of the gallon they obtain a Renewable Identification Number (RIN). A RIN is a value that is equal to 1.0 gallon of ethanol equivalent. Currently a RIN can be generated when biogas from landfills, sewage waste treatment plants, and manure digesters are used as transportation fuel. Each MMBtu of biogas will have the equivalent of approximately 13 gallons renewable fuel equivalent. (1,000,000 Btus/ 77,000 Btu's gallon = 13 RINs / MMBtu of biogas).

FIGURE 9



With this RIN purchased at market rates, obligated parties are now able to offset and retire 1 gallon of their blending obligation for that year. The following graph shows how RIN pricing can and will fluctuate based on the supply and demand of available/required fuel.

FIGURE 10



The demand is driven by EPA's year by year requirement, which is a defined ramp up schedule through 2022 to reach the 21 billion gallons of non-corn ethanol based biofuels. EPA has the authority, should supply not be available, to hold the prior year mandate constant and role forward the ramp up obligation all within the window from now through 2022. It should again be noted that RIN pricing alone is subject to influence from both the Federal policy and market supply/demand and therefore is expected to continue to be a volatile market. Using biogas to offset vehicle fuel should be done solely on the merits of what the cost offset for current and future diesel pricing would be at the local site. Where excess biogas can be advantageously converted to offset diesel at or below historical/future local diesel cost a case by case analysis should be considered.

Themes of successful biogas projects

As follows is a list of projects that have, in the fairly recent past, been put into operation or are under construction. Many observations can be taken from these example project characteristics, but most share common underlying characteristics can be drawn from related to biogas to electricity projects share many of the same characteristics:

- All utilized the 30% Federal investment tax credit or 1603 grant in lieu of tax credit as part of the funding package. If this program wasn't available some or all of the projects may not have proceeded
- All relied heavily upon avoided costs of land disposal (tipping fees) as part of the overall economics
- Several were able to receive attractive (relative to current market) tariff rates from utilities
- Most were at substantial scale (e.g. "industrial" versus "on farm")
- A few took advantage of the Federal New Market Tax Credit program

Example project #1

Private development of high strength liquid waste digester with 3.0+ MW from 5+ large food manufacturers' feedstocks

- Primary Driver – long-term cost and environmental risk associated with land application of waste water
- Assembled long-term (10-years) feedstock contracts w/tipping fees
- Able to procure power purchase agreement at adequate rate
- Utilized proven technologies with performance guarantees acceptable to debt community (non recourse debt)
- Utilized combination of equity, mezzanine funds, vendor financing state loans, NMTC funds and debt to finance (approx. $28.5 MM project)

Example project #2

Public expansion turned private development with 1.5+ MW of electrical power from 3 large food manufacturers' feedstocks

- Primary Driver – Opportunity to expand core manufacturing and manage odors in community with overburdened POTW
- Formed joint venture to take advantage of economies of scale
- Negotiated 20 year power sales with local utility at adequate rates
- Paired NMTC and 1603 grant to offset capital costs of project$30 MM investment

Example project #3

High strength liquid waste digester with 250 kW from food processor

- AD to power solution identified as most optimal after performing cost benefit impact of anaerobic, aerobic, and open pond based technology
- Allowed manufacturer to grow core business and reduced regulatory risks
- Paired NMTC and Investment Tax Credit to offset capital costs of project
- Over $23 MM plant expansion including $7 MM anaerobic waste treatment plant

Example project #4

Tax exempt entity owned high solids digester with 350 kw of electrical power

- Campus sustainability initiatives, tie to research curriculum
- University foundation investment diversification
- Formation of a taxable corporation in order to become eligible for the 1603 grant in lieu of tax credit.

Conclusions

The single largest challenge to continued digester development in the State appears to lie at the federal level. The pending expiration of the 30% Investment Tax Credit (ITC) for projects which do not "begin construction" before January 1, 2014 would have a huge impact on projects and their ability to get completed. If this program is allowed to expire very few projects, if any, would likely be economically prudent unless absolutely necessary (e.g. as a result of a regulatory requirement). In particular, on farm digesters may experience a larger gap than industrial projects who are more likely to charge tipping fees for waste received.

In our analysis we looked at three primary potential scenarios for helping close the potential funding gap if the investment tax credit is allowed to lapse at the federal level. If the project could obtain a loan at an interest rate of 2% with a 15-year term, the project would benefit $292,573 annually versus the current market for debt for typical projects. In terms of net present value or today`s dollars, the gap could be reduced (on an NPV basis) by $2.5 MM assuming an 8 percent discount rate over the project life of 20 years. If the project, in our general example set at $100,000 of annual property tax, did not have to bear this burden, nearly $1 MM of this hypothetical gap (on an NPV basis) could be filled. Finally, we evaluated the scenario of a low interest subordinated, interest only loan with a balloon of the loan principal due at the end of a 10 year term. Assuming this loan is equal to the amount of a $4.5 MM "gap", the net benefit on an NPV basis would be in the range of $1.8 MM.

TABLE 12

Potential Impacts of Digester Project Financial Variable Adjustments			
		Net Present Value	Annually
Base case	"Gap"	$4,500,658	$525,810
Lower interest rate on senior debt	Benefit	$2,504,272	$292,573
Property tax exemption	Benefit	$981,815	$100,000
Interest-only sub-debt with balloon	Benefit	$1,811,988	$ 270,040
Total benefit		$5,298,075	$662,613

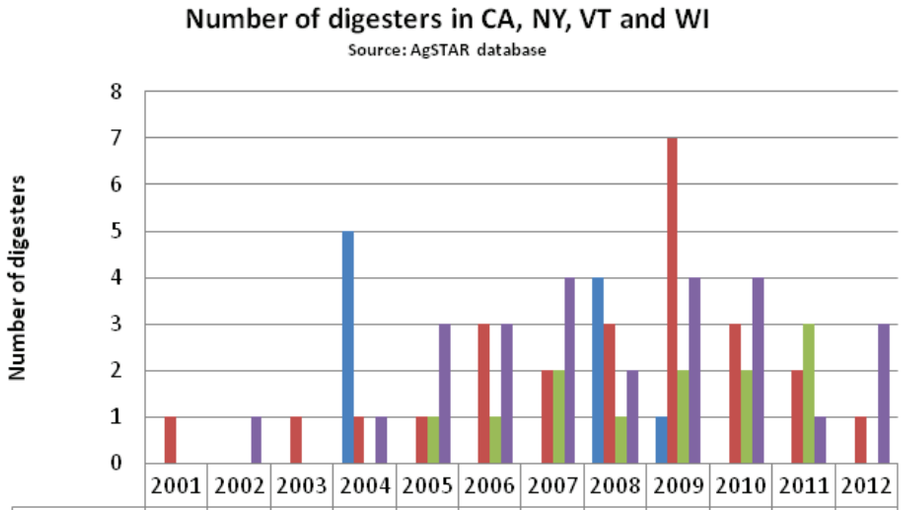
The continued rising cost of diesel fuel, along with emerging proposed amendments to the Renewable Fuels Standard 2 supporting "advanced biofuel", could also result in an economic model for biogas as a transportation fuel, specifically in captive public or private fleets, that is worth exploring further. This particularly becomes important if incentives based on electrical production (at the Federal Level) are allowed to lapse.

Appendix 1

Summary of selected state level incentives for biogas

This Appendix includes overview of the current incentives for the states with the most recent biogas applications. The graph below exhibits number of digesters build in a particular year for each state in the last decade. Although the incentives change trough the time, it can be seen that the states with the most digesters continue to support the biogas development.

FIGURE 11



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
California	0	0	0	5	0	0	0	4	1	0	0	0
New York	1	0	1	1	1	3	2	3	7	3	2	1
Vermont	0	0	0	0	1	1	2	1	2	2	3	0
Wisconsin	0	1	0	1	3	3	4	2	4	4	1	3

The attachment also provides a brief overview of the incentive in the neighboring states, such as Iowa, Illinois and Minnesota. From the overview below it can be seen that the neighboring states took different approaches to encourage renewable energy and biogas development. For example, Minnesota and Iowa have higher renewable energy goals set through renewable portfolio standards. On the other side, Minnesota provides zero percent interest loan for ten years for digester projects to spur biogas development. In addition, Illinois and Iowa allow larger project sizes to participate in the net metering systems.

California

Renewable Auction Mechanism (RAM)

The Renewable Auction Mechanism (RAM) is a state program designed to streamline the procurement process for distributed generation projects between 3 MW and 20 MW. The RAM is a reverse auction which occurs twice annually for each of the three investor-owned utilities in the state. Each utility is responsible for procuring their proportionate share of the 1,299 MW total based on their relative electricity sales. Each bid is screened by the utility for viability and then selected based on

price, starting with the least cost project, until the utility reaches their MW limit for that auction. The selected projects receive a standard contract from the utility.

Feed-in-tariff

All investor-owned utilities and publicly-owned utilities with 75,000 or more customers must make a standard feed-in tariff available to their customers. The tariffs will be available until the combined statewide cumulative capacity of eligible generation installed equals 750 megawatts (MW) for the general feed-in tariff program, and 250 MW for the bioenergy feed-in tariff program. The eligible technologies are separated into three project type categories: baseload (bioenergy and geothermal), peaking as-available (solar), and non-peaking as-available (wind and hydro).

The feed-in tariff allows renewable energy generators to enter into 10-, 15- or 20-year standard contracts with their utilities to sell the electricity produced by small renewable energy systems (up to 3 megawatts). The price paid will be based on the Renewable Market Adjusting Tariff (Re-MAT), and it includes RECs.

Self-generation incentive program

Self-Generation Incentive Program (SGIP) offers incentives of $0.48/W for various forms of combined heat and power (CHP) projects. Systems with a capacity of 30 kilowatts (kW) or greater will receive 50% of incentive up-front; 50% will be received based on actual kWh production over the first 5 years. For projects under 30kW, 100% of the incentive will be paid up front. The cap is $5 million, or 60% of eligible project costs, whichever is less. The incentive payment is available for projects of 3 MW or less. RECs stay with the renewable energy generators.

Interconnection standards

The interconnection standards ("Rule 21") apply to renewable energy systems connecting to an investor-owned utility's distribution grid, non-export generating facilities connecting to an investor-owned utility's transmission grid and all net metered facilities in an investor-owned utility's service territory. Rule 21 clearly defines a series of steps, with the fixed timelines, to filter applicants into the study path most suited for their projects. In general, the non-exporting systems qualify for the fast track application procedure, while exporting system use a detailed study eligibility process. Net metered facilities are exempt from most of the fees.

Net metering

California's net-metering law allows net metering up to 5 percent of an aggregate customer peak demand as the sum of the non-coincident peak demands of all utility customers. Net excess generation (NEG) is carried forward to a customer's next bill. Customers have the option of rolling over any remaining NEG from month-to-month indefinitely, or they can receive financial compensation from their utility for the remaining NEG. In general, the RECs stay with customers. Technologies eligible for net metering (up to 1 MW) are exempt from interconnection application fees, as well as from initial and supplemental interconnection review fees.

Customer-generators with systems sized between 10 kW and 1 MW who are subject to time-of-use rates are entitled to deliver electricity back to the system for the same time-of-use (including real-time) price that they pay for power purchases. However, time-of-use customers must pay for the metering equipment capable of making such measurements.

Public benefits funds for renewables and efficiency

The state directed the state's three major investor-owned utilities to collect a "public goods charge" (PGC) on ratepayer electricity use from 2002 through 2012 to create public benefits funds for:

- Renewables: $65.5 million annually
- Efficiency: $228 million annually
- RD&D: $62.5 million annually

Further commission action will be needed to continue funding these programs beyond 2012.

Renewables portfolio standard

California's Renewables Portfolio Standard (RPS) requires California's electric utilities to have 33% of their retail sales derived from eligible renewable energy resources in 2020 and all subsequent years. The law established interim targets for the utilities as shown below:

- 20% by December 31, 2013
- 25% by December 31, 2016
- 33% by 2020

Publicly owned municipal utilities (POUs) are not regulated by the CPUC; they are required to establish procurement requirements based on the interim goals above. The biomethane contracts signed before March 29, 2012 are eligible for compliance if certain conditions are met.

California's carbon credits market

California developed its own cap-and-trade market overseen by the California Air Resources Board (ARB).The board has approved four types of projects as eligible to sell carbon credits, and one of them is anaerobic digestion from dairy and swine farms. These types of anaerobic digesters anywhere in the U.S qualify for the California market. In general, Carbon credits are stored electronically in registries. Registries are essential for issuing, holding, and transferring carbon credits. Once a carbon project is issued with credits, the registry gives each one a unique serial number so that they can be tracked through their entire life-cycle. Registries also facilitate the retirement (surrendering) of credits for carbon neutrality purposes, ensuring credits are not resold at a later date.

New York

RPS customer-sited tier regional program

The incentive is based on actual and expected energy production from qualified systems. In order to participate in the program, applicants must submit a bid to NYSERDA as a $/kilowatt-hour ($/kWh) incentive request. The bid evaluation process is competitive. Minimum system size is 10kW and the maximum is also limited to that needed to supply 110% of historic or calculated on-site electricity needs. A bonus of 15% from the requested incentive level is available for projects that are located in certain areas. Strategic locations defined by individual utilities.

The maximum incentive is 50% of installed costs; $6 million per applicant per round; and $3 million per individual project. The incentive payments last for up to 3 years, with a yearly budget around of $227 million.

Biogas systems must meet an air emission limit of no more than 1.6 lbs of NOx per MWh. Biogas facilities must be grid connected and installed behind the electricity meter of a single customer.

Local option - solar, wind, and biomass energy systems exemption

The current state tax property law allow a 100 percent 15-year real property tax exemption for farm-waste energy systems. As currently effective, the law is a local option exemption, meaning that local governments are permitted decide whether or not to allow it.

The maximum rated system capacity for eligible farm-waste energy systems is 400 kilowatts (kW) and systems must be connected to the electric grid and operated in accordance with the state's net metering law in order to qualify. The exemption applies only to general municipal and school district taxes; it cannot be applied to special assessments or special ad valorem levies.

Anaerobic digester gas-to-electricity rebate and performance incentive

The Anaerobic Digester Gas-to-Electricity program combines both an up-front incentive for new installed capacity and a performance-based incentive for energy production.

Customer eligibility is generally limited to those that that pay the RPS surcharge on their electric bills, such as customers of the state's major investor-owned utilities. The electricity generated under the program will be counted towards the Customer-Sited Tier (CST) portion of the state RPS. The recent project solicitation allowed a total of $57 million has been authorized to fund incentive payments through 2015 (annual budgets range from roughly $10 - $13 million), limited to $1 million per Anaerobic Digester Gas (ADG) system. Only new systems of at least 100 kW that use dairy farm waste or dairy product processing waste for at least 50% of their feedstock input are eligible for funding.

Eligible system size is limited to either: (1) the capacity eligibility limit on farm based electricity generating equipment under New York's net metering law which is currently set at 1 megawatt (MW), or (2) the customer's approximate Peak Connected Load.

The total incentive available under PON 2684 includes several elements:

- Fixed Capacity Incentive: Ranges from $12,500 - $100,000, depending on the type of equipment being employed
- Variable Capacity Incentive: Ranges from $125/kW - $2,000/kW, depending on the type of equipment being employed.
- Performance-Based Incentive: $0.025/kilowatt-hour (kWh) on up to 10 years of estimated electricity production using a 75% capacity factor.
- Additional Component Capacity Incentives: Available for systems that employ higher quality biogas clean up measures, have grid upgrade costs exceeding $100,000, have black start

capability, are designed to accept significant quantities of food waste, have contracts with institutional sources for acceptance of food waste feedstock, or employ cooperative group management services with at least two other digesters. These incentives include a fixed and variable component.

Renewable power procurement policy

The Executive Order No. 111 commits the state government to purchase a portion of its electric power from renewable energy resources -- at least 10% from resources such as wind, solar thermal, photovoltaics (solar electric), sustainably managed biomass, tidal, geothermal, methane waste and fuel cells by 2005, increasing to 20% by 2010. The order applies to all agencies and departments over which the governor has executive authority, and all public benefit corporations and public authorities whose heads are appointed by the governor.

State entities can fulfill their renewable power procurement obligations through on-site generation or by purchasing renewable energy on the open market. Although Executive Order No. 111 is not specific to activities purchases beyond 2010, the RPS projections used by the New York Public Service Commission (PSC), which extend through 2015, incorporate green energy purchases by state government throughout the life of the standard.

Interconnection standards

The New York Public Service Commission (PSC) recently amended Standard Interconnection Requirements (SIR) in order to simplify and expedite the interconnection application and review process, and to adopt changes made to net metering law in 2012. The SIR rules apply to systems up to 2 megawatts (MW) in capacity located in the service area of one of New York's six investor-owned local electric utilities. The SIR addresses technical guidelines for interconnection and application procedures, with two separate sets of interconnection procedures and processes:

- Expedited Process: systems up to 50 kW are eligible for a simplified or expedited six-step process.
- Basic Process: All systems larger than 50 kW up to 2 MW.

Utilities are required to maintain a web-based system for providing information on the status of interconnection requests to customers and contractors. It also requires that utilities offer a web-based application process for systems of 25 kW or less. The requirements specifically state that utilities are not permitted to require customers to purchase general liability insurance; however, the PSC does encourage distributed generation owners to purchase insurance for their own protection.

Net metering

Net metering is available on a first-come, first-served basis to customers of the state's major investor-owned utilities, subject to technology, system size and aggregate capacity limitations. Publicly-owned utilities are not obligated to offer net metering. The net metering limit for biogas projects are: 1 MW (farm-based only) and Micro-CHP: 10 kW (residential only). For most types of systems, customer net excess generation (NEG) in a given month is credited to the customer's next bill at the utility's retail rate. The credit is based on all utility charges and customer may opt to cash-out the kWh excess at the avoided cost. The ownership of renewable energy credits (RECs) and other environmental attributes associated with energy production from net metered systems remains unaddressed.

System benefits charge

New York's system benefits charge (SBC), established in 1996 by the New York Public Service Commission (PSC), supports energy efficiency, education and outreach, research and development, and low-income energy assistance. To support the SBC program, the state's six investor-owned electric utilities collect funds from customers through a surcharge on customers' bills. The SBC program is administered by NYSERDA and funds numerous programs to improve the state's transmission and distribution infrastructure. The program goals include improving system-wide reliability and increasing peak-electricity reductions through end-user efficiency actions; improving energy efficiency and access to energy options for under-served customers; reducing the environmental impacts of energy production and use; and facilitating competition in electricity markets to benefit end-users. Only customers that pay the SBC are eligible for assistance through the programs it funds. The current SBC Technology and Market Development Program has an overall budget of $527.3 million.

Renewable portfolio standard

The New York Public Service Commission (PSC) requires utilities, except the municipal utilities, to acquire 30% electricity by 2015 from eligible generators. Of this 30%, approximately 20.7% of the target will be derived from existing renewable energy facilities and one percent (1%) of the target is expected to be met through voluntary green power sales in 2015.The remainder will be derived from new, eligible resources centrally procured by the New York State Energy Research and Development Authority (NYSERDA). Eligible new renewable resources fall into two tiers -- a Main Tier (roughly 91.56% of incremental renewables generation) and a Customer-Sited Tier (roughly 8.44%).

NYSERDA manages an RPS fund gathered through a surcharge on each kilowatt-hour sold by the state's investor-owned utilities. The RPS surcharge is separate from and in addition to the state system benefits charge (SBC). Customers exempt from contributing to the SBC are also exempt from the RPS charge. Municipal utilities do not fall under the jurisdiction of this program, but have been encouraged by the PSC to adopt similar programs.

Vermont

Investment tax credit

Vermont offers an investment tax credit for CHP system of 50 MW or less for installations of renewable energy equipment on business properties. The credit is equal to 24% of the "Vermont-property portion" of the federal business energy tax credit. For solar, small wind, and fuel cells this constitutes a 7.2% state-level credit for systems placed in service on or before 12/31/2016. After this date, solar (except hybrid solar lighting) technologies are eligible for a 2.4% credit. For microturbines, and combined heat and power systems, the credit is a 2.4% state-level tax credit for systems place in service on or before 12/31/2016. Any unused tax credit may be carried forward for 5 years. All equipment must meet the same requirements as the Federal Investment Tax Credit.

GMP - Biomass electricity production incentive

Green Mountain Power Corporation (GMP), Vermont's largest electric utility, offers a production incentive to farmers who own systems utilizing anaerobic digestion of agricultural products, byproducts or wastes to generate electricity. GMP purchases the renewable energy credits for up to $0.04 per kWh, with full subscription of the GMP voluntary Cow Power tariff. Attributes associated

with production in excess of voluntary customer demand will be sold on the regional market where possible. The farmers sell the electricity as a separate commodity under the Vermont Standard Offer Program. Eligible systems must be connected to the grid, although net metering is another option for farmers, it is not available under this arrangement.

GMP sells the renewable energy credits (RECs) and other environmental attributes (i.e. Carbon Credit) generated under this arrangement as part of GMP Cow Power, the utility's green power program. This program offers customers the opportunity to purchase renewable energy for $0.04 per kWh above the retail cost of electricity under any rate class as a tariff rider.

Standard offer for qualifying SPEED resources

Vermont enacted a feed-in tariff policy requiring all Vermont retail electricity providers to purchase electricity generated by eligible renewable energy facilities through the Sustainably Priced Energy Enterprise Development (SPEED) Program via long-term contracts (10-25 years) with fixed standard offer rates.

The feed-in tariff is for the systems up to 2.2 megawatts (MW) in capacity that are commissioned on or after September 30, 2009. SPEED projects must apply for and be granted a "Certificate of Public Good." Projects 150 kW and less may apply for the "Certificate of Public Good for Net Metered Systems. Eligible wood biomass resources may only receive the standard offer if the plant's system efficiency is 50% or greater.

Request for Proposal (RFP) process is released annually. The PSB set avoided-cost rates to be used as annual per-kWh cost caps for contracts. Contracts are selected competitively based on the proposed $/kWh structure. The RFPs will be capped at 5 MW capacity each year from 2013-2015, 7.5 MW each year from 2016-2018, and 10 MW each year in 2019 and 2020. The renewable energy credits (RECs) generated are transferred to the retail electric provider that purchases the power from the renewable energy facility, except in the case of a facility using methane from agricultural operations. In that case, the plant owner retains ownership of the RECs and may sell them if desired. Starting April 1, 2013, there will be annual increases to the program cap, until the 127.50 MW cumulative capacities is reached by 2022.

Local option—Property tax exemption

Vermont allows municipalities the option of offering an exemption from the municipal real and personal property taxes for certain renewable energy systems. The state property taxes would still apply. Eligible systems include conversion of organic matter to methane systems including land upon which the facility is located, not to exceed one-half acre. Adoption of this exemption varies by municipality, but the exemption generally applies to the total value of the qualifying renewable energy system and can be applied to residential, commercial, and industrial real and personal property.

Renewable energy systems sales tax exemption

Vermont's sales tax, currently 6 percent, exemption for renewable-energy systems generally applies to systems up to 250 kilowatts (kW) in capacity. The exemption is available for both, grid-tied systems and off-grid systems. Renewable energy definition includes biogas projects from sewage-treatment plants and landfills, and anaerobic digestion of agricultural products.

Interconnection standards

Vermont has adopted separate interconnection standards for net-metered energy systems that are 150 kW or less, and for all other distributed-generation (DG) systems. The maximum system capacity for net metered systems is 500 kW.

Vermont requires electric utilities to offer net metering to all customers with photovoltaic (PV) systems, wind-energy systems, fuel cells or biomass-energy systems until the cumulative generating capacity of net-metered systems equals 4% of a utility's peak demand.

DG systems that meet certain technical screening criteria are eligible for the "fast track" interconnection process, which requires no special studies. Systems not eligible for "fast track" interconnection require a feasibility study, a system-impact study, and/or a facilities study. Reasonable, specific timelines apply to "fast track" interconnection and general interconnection.

Net metering

Net metering is generally available to systems up to 500 kW in capacity that generate electricity using eligible renewable-energy resources, and to micro-combined heat and power (CHP) systems up to 20 kW.

Biogas from sewage-treatment plants and landfills, and anaerobic digestion of agricultural products, byproducts and wastes are explicitly included. The term "renewable energy" excludes solid waste that is not agricultural or silvicultural, as well as nuclear fuel, coal, oil, propane and natural gas.

Net metering is available on a first-come first-served basis until the cumulative capacity of net-metered systems equals 4% of a utility's peak demand during 1996 or the peak demand during the most recent full calendar year, whichever is greater. Renewable energy facilities on military installations do not affect the cap. Any customer net excess generation (NEG) is carried over to the customer's next bill. Any NEG shall be used within 12-months of the month earned, if not, it is granted to the utility with no compensation for the customer. Net metering is also available under a time-of-use metering arrangement. Vermont also allows "group net metering." The utility is required to bill all customers of the group individually.

Clean Energy Development Fund (CEDF)

Vermont's Clean Energy Development Fund (CEDF) promotes development and deployment of cost-effective and environmentally sustainable electric power and thermal energy resources -- primarily renewable energy, combined heat and power (CHP), thermal, and geothermal energy. Legislation enacted in 2012 authorized $3 million in appropriations from the Vermont general fund to the CEDF as long as the general fund is in the black. That transfer should take place after May 1, 2013.

The CEDF is authorized to support renewable-energy resources, and CHP systems. Eligible renewable-energy systems include biomass fuels such as wood, agricultural or food wastes, energy crops and organic refuse-derived waste. Municipal solid waste is not eligible. CHP systems must have a design system efficiency of at least 65% and must meet Vermont's air-quality standards in order to qualify. The CEDF may be used to support projects that sell power in commercial quantities (especially those projects that sell electricity to Vermont utilities), projects to benefit publicly owned or leased buildings, renewable-energy projects on farms, and small-scale renewable energy for homes and businesses.

Other states

Iowa

- *Corporate production tax credit* of 1.5¢ per kilowatt-hour for up to 2.5MW projects In addition, Iowa offers $4.50 per million BTUs of biogas used to generate either electricity or heat for commercial purposes.
- *Net metering policy* allows anaerobic digestion systems up to 500kW to sell power to investor-owned utilities at retail rates.
- *Alternate Energy Revolving Loan Program* provides biomass projects with a zero interest loans for up to 20 years. The maximum loan amount is $1 million and up to 50 percent of the total project costs.

Illinois

- *Biogas and Biomass to Energy Grant Program* provided $225,000 for biogas-to-energy systems or up to 50 percent of the total project costs.
- *Net Metering Policy* allows systems up to 2MW to participate in net metering with the overall limit of 5 percent of the utilities peak demand from previous year.
- *Renewable Portfolio Standard* requires investor owned utilities and retail suppliers to procure 25 percent of their power from renewable energy sources by 2026.

Minnesota

- *Methane Digester Loan Program* provides a zero percent loans with the maximum term of 10 years. State participation is limited to 45% of the loan principal in the case of participation loans and may not exceed $250,000 for either participation or direct loans.
- *Net Metering Policy* allows generating facilities under 40 kW to sell their excess power to utilities at retail rates.
- Additionally, the RPS in Minnesota sets different renewable energy goals for different types of utilities on how much of the renewable energy needs to come from renewable energy sources, including:
  - Xcel Energy: 31.5 percent by 2020.
  - Standard for Non-Xcel Public Utilities: 26.5% by 2026
  - Standard for Non-Public Utilities: 25% by 2026.

About the Wisconsin State Energy Office

The State Energy Office (SEO) is committed to supporting Wisconsin's goal of: generating electric power and transportation fuels from renewable resources; capturing more of the emerging bioindustry and renewable energy market; and leading the nation in groundbreaking research that will make clean energy more affordable and will create good paying Wisconsin jobs.

The focus of the SEO

- Ensure and facilitate implementation of energy independence initiatives
- Serve as the single point of contact and ombudsperson for businesses, local units of government and NGOs pursuing bio development, energy efficiency, and energy independence
- Develop energy independence policy options
- Identify federal funding opportunities and facilitate state / local government and private sector application for funding
- Serve as the State Energy Office and perform duties necessary to maintain federal designation and federal funding

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