Project Title: Torrefaction and Densification of Biomass Fuels for Generating Electricity

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Congressional District: 5th Congressional District

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MILESTONE 9 REPORT

Executive Summary:
This project researched torrefaction and densification of biomass feedstocks to develop an efficient and economical biomass supply chain. The approach was to develop and optimize a torrefaction and densification regime that will improve storage capabilities, handling methods and biomass feedstock uniformity for the production of renewable baseload electricity, heat, or syngas. The project was designed to support the following goals:

- **Goal 1:** Generate electricity, heat or syngas from renewable biomass energy sources that are readily available in Minnesota and approaching economic feasibility
- **Goal 2:** Strengthen the economy of rural Minnesota through value-added processes that capture renewable biomass energy production capability
- **Goal 3:** Increase accessibility to information that facilitates the adoption of biomass technologies to generate electricity and reduce fossil fuel use

The main work activity conducted for Milestone 9 consisted of an independent demonstration-scale Test Gasification of the biocoal material and an overall Economic Analysis for generating electricity with torrefied and then densified biomass fuels (biocoal). Milestone 9 addresses the project goals in the following ways:

- Proves that biocoal material handles, feeds, and gasifies in an updraft gasification similarly to that of coal and other raw biomass feedstocks to produce high quality producer gas
- Provides an overall economic assessment of using corn stover based biocoal to produce electricity at 10% and 30% co-firing ratios at an “average” (500 MW) pulverized coal power plant
- Determines and provides an overall economic sensitivity analysis to help potential future commercial scale biocoal plant developers and biocoal users (utilities) to assess the pricing sensitivity of the biocoal and on final electricity customers on a $/kwh basis
- Proves the overall economic and technical feasibility of using biocoal to produce electricity at economically practical prices using existing infrastructure.
Technical Progress: Test Gasification

Background

With the completion of the Milestone 8 Report in late October 2010, the team began to focus on the final elements within the grant activity: the test gasification and final economic and feasibility analyses. For the test gasification, since the biocoal product had already been produced earlier in the grant cycle, the main effort that remained was to develop a relationship with and to contract for test gasification services on a demonstration-scale gasification system using the biocoal material.

In early 2011 we were introduced to Coaltec Energy USA and we set a mutually agreeable biocoal gasification trial contract for testing to be completed during the middle of February 2011. A physical meeting took place in late January 2011 and the actual gasification testing took place on February 17\textsuperscript{th} and 18\textsuperscript{th}, 2011 in Carterville, IL at the Coaltec Energy USA demonstration-scale updraft gasification system.

Technical Report

In early 2011 we completed a two day, 100% biocoal gasification test protocol and contract with Carterville, IL-based Coaltec Energy USA. The gasification system, a demonstration scale updraft style system, was used for two days to obtain general biocoal gasification suitability data and to obtain simulation modeling producer gas estimates at a variety of co-firing ratios. The two testing days, February 17 and 18\textsuperscript{th}, 2011, went as smoothly as one could hope for a demonstration-scale gasification facility and a “new to the world” fuel. The material gasified well, showed exceptional material handling characteristics and, in the eyes of Coaltec, showed good promise as indicted in their report. The Executive Summary of the report is reproduced here for reference.

On February 17\textsuperscript{th} and 18\textsuperscript{th} 2011, Coaltec Energy USA, using its demonstration scale updraft gasification system in Carterville, IL, conducted a 100% torrefied and densified corn stover (biocoal) gasification trial. The 4 tons of biocoal for the test was supplied by Bepex International, LLC as a part of their Xcel Energy Renewable Development Fund (RDF) grant activities (Milestone 9 – RD3-4).

The purpose of the gasification trial was to determine the general suitability of the biocoal as a fuel for gasification (material handling, producer gas production, etc.), determine the energy produced during the gasification trials (energy and mass balances), determine (using simulation models) the producer gas production for various blends of biocoal and coal (fuel flexibility), and identify any potential advantages or disadvantages of the biocoal for use as a gasification fuel.
Overall, the biocoal material handled well flowing into the conveyers, the walking floor feed hopper and the hydraulically controlled rams feeding into the gasifier. The energy density and permeability of the fuel allowed easy control of the gasification air — making for appreciable temperature control. The biocoal feeding rate averaged 800 lbs/hour to produce 6 MMBTU/Hour with a maximum feeding rate of 1,000 lbs/hour for a short period of time.

The biocoal material prepared and delivered by Bepex has positive characteristics. It is porous and doesn’t compact easily, which makes controlling air penetration within the gasification bed easy. It has a higher energy content than most raw biomass fuels and has a low ash content, so it provides a significant amount of energy for a small volume of fuel. Additionally, the material flows easily within the gasifier, so it improves the efficiency inside of the unit by making it easier to utilize all of the bed area.

The potential of utilizing biocoal in co-firing gasification applications appears to hold promise. The high energy content combined with the low ash, the ability to penetrate the material with air, and the high fixed carbon (which increases temperature in the primary unit) are all characteristics to improve the performance when working with poorer quality fuels, such as in distributed gasification applications with manure, wet distillers grains, etc.

Technical Progress: Feasibility & Economic Analysis

The overarching question that was to be investigated during this demonstration project was the feasibility and economic analysis of using renewable biomass feedstocks for biomass torrefaction and densification to ultimately produce renewable electricity, heat, or syngas.

Over the last three years, the combined team has proven the feasibility of such a supply chain through field collection of raw biomass using innovative single-pass harvesting systems; through design, fabrication, testing and ultimately demonstrating a pilot-scaled biomass torrefaction and densification production plant to produce over 30 tons of biocoal; and through testing the product at a pilot-scale pulverized coal boiler, demonstration-scale gasification facility and an industrial-scale stoker grate boiler to prove the feasibility of using the fuel to produce electricity, syn-gas, and heat respectively in industry standard settings.

Prior Milestone Reports focused more heavily on the technological perspective of the design, fabrication and use of the fuel versus economic analysis. This final section of the Milestone report will provide greater
discussion and analysis of the economic drivers of renewable baseload electricity production using biocoal to co-fire with coal in existing pulverized coal power plants.

Prior Milestone Reports, specifically Milestone 6, stated: “A detailed discussion of the co-firing economics based on a commercial scale biocoal production plant will be included as a part of the Milestone 9 report to include estimates of carbon dioxide reductions, emission reductions (NOx and SO2), sensitivity analysis, and the potential impact to the final cost of delivered electricity on a dollar per kw-h basis with and without a price for carbon emissions (USD/Ton CO2).”

Based on this we have augmented the functionality of our existing biomass torrefaction and densification financial and economic model to better derive answers that were originally purposed at the start of the grant activities, “Perform an overall economic analysis for generating electricity with torrefied and then densified biomass fuels,” as well as the goals stated in our Milestone 6 Report.

As a result of this economic model augmentation, the team has developed an extension of the model to determine the co-firing economics when using a torrefied and densified corn stover product. The model has a multitude of variables of which are tailored to mimic the Sherco power facility owned by Xcel Energy. We feel that a complete review of the economics and potential emissions reductions and ultimate feasibility of this scenario would be most useful to Xcel Energy and the ratepayers who could benefit from this analysis. By focusing on this specific scenario we are not forced to entertain an entirely new feedstock, type of coal or combustion system (pulverized coal) into the equation.

The following analysis will focus on one of the largest power generating assets within the Xcel Energy portfolio: Sherburne County’s three unit facility otherwise known as “Sherco”. For our analysis we will focus on Unit #1, a 690 MW pulverized coal boiler unit.

**Sherburne County (“Sherco”) and Xcel Energy Background:**

Xcel Energy owns and operates one of the largest coal powered electrical power facilities in the Midwest – known as Sherburne County or “Sherco”. The power facility maintains three boilers with a combined capacity of 2,431 MW that have been in service since 1976 (Unit 1), 1977 (Unit 2) and 1987 (Unit 3). With Unit 3 being co-owned by Xcel Energy and Southern MN MPA. For the subsequent analysis we analyzed Unit 1, a 690 MW pulverized coal powered boiler. We varied the co-firing ratio in our model between 0% and 30% biocoal on a btu basis as well as 12 other model inputs for the subsequent analysis to determine the impact on the cost of electricity to the average Xcel customer in 2010 in $/kwh and estimated annual increase in average residential electric bills.

To determine the relative change in pricing to the average customer in 2010 in $/kwh we used reported data within the Xcel Energy 2010 10-K filing with the SEC to determine that the average price of electricity for industrial, residential and commercial customers during the 2010 FY was **7.7121¢ per kwh or $0.077121/kwh**. Then using the economic model data we removed the cost of the fuel per kwh ($0.01954 / kwh) from this average price to determine the average base price of electricity net of fuel costs ($0.05758). The net of fuel cost includes transmission costs, operations & maintenance (O&M) costs, capital recovery costs, and other general and administrative overhead costs associated with the cost of producing and delivery electricity. Then as we changed the model inputs a new weighted average cost of fuel (based on the co-firing ratio) was automatically calculated and then added to the previously calculated average base price net of fuel costs ($0.05758) to determine the new forecasted average cost of electricity to Xcel customers.
To determine the baseline emission rates (0% co-firing or 100% coal) at the Sherco power facility we used EIA filings from 2009 to determine emission rates in lbs/MWh for mercury (Hg), CO$_2$, NO$_X$, and SO$_2$. The following emission rates were used to form the reference point emission rates for Sherco Unit 1 within the economic model.

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat Rate (btu/kwh)</td>
<td>10,418</td>
</tr>
<tr>
<td>Mercury Emission Rates lbs/MWh</td>
<td>4.08E-05</td>
</tr>
<tr>
<td>CO$_2$ lbs/mmbtu</td>
<td>213.4</td>
</tr>
<tr>
<td>NO$_X$ lbs/MWh</td>
<td>1.81</td>
</tr>
<tr>
<td>SO$_2$ lbs/MWh</td>
<td>3.13</td>
</tr>
</tbody>
</table>

Then with the baseline emissions calculated we were able to use the co-firing module within the economic model to determine how the various co-firing blends of biocoal with coal would impact the estimated emission rates. The economic model leveraged our actual pilot-scale pulverized coal co-firing emission rate reductions at various co-firing ratios to interpolate the estimated emission reductions (percentage basis) for a given co-firing ratio model input for NO$_X$ and SO$_2$. For CO$_2$ we assumed that the net carbon emission for biocoal was zero, such that for each mmbtu of power replaced by biocoal it would reduce CO$_2$ emissions by 213.4 lbs. For Mercury emission reductions we used the model inputs as provided above and the analytically determined values of Hg in the biocoal to support the model outputs.

With the new emission rates calculated, the model would then also automatically calculate the value of the reduced emissions using the model input value for the various allowances, or abatement avoidance costs. Further details of how the model applied value for the various emissions is provided in the Economic Model Baseline section below.

**Economic Model Baseline:**

With any economic or financial model it is important to ensure that the baseline assumptions or model inputs are justifiable and as accurate as possible to ensure the output of the model is as realistic as possible. The following section details the baseline assumptions and model inputs that are used in the economic model and the rationale behind their selection and how they impact the final output – the change in price of electricity in $/kwh for the average Xcel energy customer at various co-firing ratios and at different model input variations (model sensitivity analysis).
One of the key outcomes from our demonstration activities was a detailed estimate for the delivered cost of raw corn stover into a proposed commercial scale biocatal production plant. A “field-to-facility” corn stover logistics system was proposed in Milestone 6 to deliver corn stover to the torrefaction plant year around. The proposed logistics system included collection and transport of round net-wrapped bales to local storage sites within 3.2 km (2 miles) of the field during the fall harvest period. This stage was followed by processing at the local storage sites throughout the year using mobile units, which convert the bales to bulk material by tub-grinding and roll-press compaction to 240 kg/m³ (15 lb/ft³) to achieve 22.7 t (25 ton) loads for truck delivery to the torrefaction plant within a 48 km (30 mile) radius. The total cost for delivering densified corn stover was estimated to be $72.38/ton and was used as the baseline economic model input.

(2) Moisture Content (% mass):
During our original pilot-scale biomass torrefaction and densification production runs, we conducted extensive moisture analysis of the inbound raw corn stover biomass. As a result of these measurements we used a baseline input value of 17% moisture for the inbound raw biomass model input for this analysis. The variation of this model input (moisture content) dynamically changes the mass and energy balance of the process within the economic model. As the mass and energy balance of the process changes, it then in turn
impacts the amount of excess energy the biocoal plant produces that could be sold to a co-location partner. As the value of the excess energy increases (moisture level down), or decreases (moisture level up), the biocoal forecasted income and balance sheet changes in the economic model. As more revenue is gained from excess energy, less money is required for each ton of biocoal to meet the required return of debt and equity investors in the plant, thereby driving down the delivered cost of biocoal, which therefore lowers the cost of electricity – the converse is true for higher moisture raw biomass.

(3) Natural Gas Utility Costs ($/mmbtu):

Natural Gas, while still a fossil fuel, produces less carbon dioxide when combusted per kwh produced and also typically has lower emissions (SO₂, NOₓ, and Hg) than power generated from coal. However, the price of natural gas has typically been and is today higher than coal on a delivered cost basis ($/mmbtu). In some cases (2008) natural gas has reached prices into the $8.00 / mmbtu range. For our baseline price we used the Henry Hub quoted price of **$4.38 / mmbtu**. It should be noted that the price of natural gas in the economic model determines the economic value of the excess heat given off by the biocoal production facility as discussed in model input (2) above. As the value of natural gas goes up, the value of the excess heat goes up for the biocoal production plant, thereby lowering the required price the production facility needs to charge to ensure a break-even return for all investors (weighted average cost of capital or WACC). This in series then lowers the price of electricity to the average customers.

(4) Coal Delivered Price ($/ton & $/mmbtu):
The coal sourced by the Sherco power facility comes from the Wyoming Powder River Basin. We modeled the price of the delivered coal to the facility as **$31.42 ($/short ton)**. The $31.42 per short ton delivered pricing was calculated by using the calculated heat rate of the average Sherco system and the Xcel Energy reported price of fuel for electricity in its 2010 10-K filing with the SEC of $1.89 / mmbtu for coal. Using 2009 reported and final data with the EIA, we calculated the above mentioned heat rate of 10,418 (btu/kwh) and a capacity factor of 72% for Sherco in 2009 which are averages for all three units. We assumed that the boiler would inherit the same heat rate as the relative level of biocoal co-firing increased for the economic model.

(5) Debt Interest Rate (%)

For our economic analysis we kept the capital structure for financing the proposed commercial scale biocoal production facilities constant at 60% debt and 40% equity (with no breakout for the difference or use of tax or developer equity). For the rate on debt, we used a baseline estimate of **7% interest rate**. Both the estimated capital structure and rate on debt were estimates derived from the latest NREL Renewable Energy Finance Tracking Initiative (REFTI) report issued on February 10, 2011. Specifically, on page 75 of the report a 7% return on term debt was average.

(6) Equity Required Rate (%)

As in model input (5) discussed above, we kept the capital structure for financing the proposed commercial scale biocoal production facility constant at 60% debt and 40% equity. For the required return for equity investors we assumed a baseline model input of **15% required return** again using the above quoted REFTI report issued on February 10, 2011. Specifically, page 68 of the report notes that average expected returns for equity investors were in the 12% range. However, to be conservative we assumed a 15% required return.

(7) Biocoal Plant Cost – (Millions of $)
Another key result from our demonstration project was to determine with some level of certainty the installed cost of a commercial-scale biocoal production plant. In our Milestone 6 Report we detailed the estimated installed cost for a 150,000 ton of finished biocoal production plant per year at $34.2 million USD. This value included inflation for three years for an estimated commissioning date of 2013. For this final report we’ve assumed (to keep our current estimates – Corn Stover, Natural Gas, Electricity, Coal, CO$_2$, SO$_2$, NO$_x$, Hg, and REC’s as fresh as possible) that the biocoal production plant is installed as of the writing of this report such that no inflation is added to the base cost of the production plant. Therefore the baseline model input cost of the commercial scale production plant used is $31.28 million USD. As the cost of the commercial scale production plant drops, less capital is required to finance the operations of the plant – thereby lowering the required payback to debt and equity investors which in turn lowers the price the biocoal plant needs to charge for each ton of biocoal produced to meet the required return (WACC).

(8) Carbon Dioxide: CO$_2$

Carbon dioxide is a reaction product during combustion of any fuel – natural gas, coal, fuel oil, gasoline, and even biomass. While there is significant evidence linking the relative levels of carbon dioxide in the atmosphere to global climate change there has been resistance to cohesive regulatory drivers being put in place on an international scale that might curb our societies continuing growth of carbon dioxide emissions. One notable exception, however, is the Kyoto Protocol’s target emission reductions of 7% below 1990 levels by 2012. Many international countries have signed on to the Protocol, but some of the world’s largest emitters, including the United States, have not.

While it is impossible to burn fuels – renewable or fossil – without generating carbon dioxide emissions, it is possible to utilize fuels that are either carbon neutral or less carbon intense (such as natural gas), or find ways to sequester the carbon that is emitted via CCS (Carbon Capture and Sequestration) technologies. The use of biocoal is virtually carbon neutral, assuming the raw biomass used in the process is sustainably harvested – meaning that for every ton of biocoal used, a power plant would be reducing approximately 1.8 tons of net carbon dioxide emissions.

The Sherco power plant uses Southern Wyoming Powder River Basin coal. Using the below reference we assumed that for each mmbtu of coal consumed in Unit 1, it produced 212.7 pounds of CO$_2$. This value is taken from the Coal Market Module (Table 12.5 p. 154 – April 2010) from the U.S. Energy Information Administration Assumptions used to generate the Annual Energy Outlook. The actual CO$_2$ emissions at the Sherco plant are provided in Figure 5: Historical Sherco CO2 Emissions (tons).

Even while the United States currently lacks a cohesive national carbon dioxide regulatory pathway, individual states have stepped in to build a patchwork of plans that have grown into regional groups. For example, in Minnesota the Next Generation Energy Act of 2007 mandated that 25 percent of the total energy used in the state be derived from renewable energy resources by the year 2025. It also sets a climate change mitigation target of cutting the state’s greenhouse gas emissions to 15 percent below 2005 base levels by 2015, 30 percent by 2025 and 80 percent by 2050. Xcel Energy was mandated to target a 30% renewable portfolio by this same timeframe (2025), of which a majority was to come from wind. Through co-firing biocoal with coal at existing power plants, we would be able to leverage existing installed assets while reducing carbon dioxide emissions and increasing renewable energy generation.
While regional strategies are important in order to lay the groundwork for CO² trading – such as on Chicago Climate Exchange – a national mandate will likely be required to truly drive the CO² market. Without a cohesive national mechanism, the price of a ton of CO²e will likely continue to trade in its current $2.00 / ton of CO²e range. However, looking into the future, many experts predict that the price of CO² will likely move towards $10 to possibly even $15 per ton should a national or international accord be struck with binding authority for CO² reduction targets. For our economic model, based on a variety of U.S. based voluntary climate exchange data, we assume a baseline value of $2.00 per ton to reflect the current reality.

**Figure 5: Historical Sherco CO₂ Emissions (tons)**

(9) & (10) Sulfur Dioxide & Nitrous Oxide: SO₂ & NOₓ

Sulfur Dioxide, a combustion reaction product of Sulfur within the solid fuel (coal or otherwise), is produced and emitted if not collected from the stack of a pulverized coal and natural gas facilities during the production of electricity. Likewise, Nitrous Oxide is also a reaction product during combustion, but its production rate is typically more dependent on the boiler conditions themselves (fuel to air ratio, boiler temperature, etc.) than the fuel. The EPA began investigating and ultimately regulating SO₂ and NOₓ in 1980 and 1990 respectively due to their impact on the formation of acid rain (Clean Air Act of 1990). This regulatory activity was successful using an allocation-based system, while also allowing trading of the allowances among utilities.

Xcel Energy has invested significant resources into the Sherco facility to reduce SO₂ and NOₓ emissions though a Wet Scrubber in Units 1 and 2 and a Dry Scrubber in Unit 3. The historical averages of these Unit emission rates are provided in the below figures. While other emission reduction technologies exist and depending on the specific regulatory drivers, emission reductions available via co-firing might provide capital avoidance for the utility however such an analysis is beyond the scope of this effort.

Nationally, we have seen the EPA regulate NOₓ, SO₂, and implement an Allowance system for utilities to find the most cost effective way to comply with the market driver. An SO₂ allowance is required for each ton of SO₂ produced by a coal-fired power plant. The EPA holds annual auctions with up to 125,000 tons
of allowances being auctioned off each year. Utilities have been given free allocations thru 2037 based on operations in base years 1985 – 1987 for SO₂ and target emission reductions. While historical pricing of these allocations have been in the hundreds of USD per emitted ton (October 2008 NOₓ - $900/Ton) the current (January 2011 - Bloomberg) pricing of these allocations are $16.59 /ton of SO₂ and $45.03 /ton of NOₓ. These are the baseline inputs for SO₂ and NOₓ value to our economic analysis model.

During our pilot scaled pulverized coal co-firing trial (Milestone 5), we also saw the use of corn stover derived biocoal with coal reduced the NOₓ and SO₂ emissions compared to firing coal only. The reduction of SO₂ came from two sources – the fact that the biocoal has a lower concentration of sulfur in the fuel itself and the fact that the ash within the biocoal has a higher concentration of natural sorbents such as calcium oxide which during combustion control the sulfur from the coal in-furnace. For our economic model we assume that for each ton of SO₂ or NOₓ emission reductions due to co-firing with biocoal are allowances that the utility will be able to sell on the spot market to effectively reduce the cost of the biocoal product. The emission reductions are interpolated from our actual pilot scaled pulverized coal co-firing trials and then matched to the specific co-firing percentage.

![Figure 6: Historical Sherco SO₂ Emissions (tons)](image-url)
(11) Mercury and Particulate Matter: Hg & PM

Similar to NO\textsubscript{X} and SO\textsubscript{2} emissions from power plants, national regulatory agencies (EPA, FERC) have realized the long-term impact of mercury (Hg) emissions from power plants and have stepped in to regulate Hg emissions. As of March 2005, with the completion of final regulations for coal-fired power plants, the EPA now has Clean Air Act (CAA) standards in place limiting mercury air releases from most major known industrial sources in the U.S.

“More specifically, EPA’s recently promulgated (2006) Clean Air Mercury Rule (CAMR) is part of a suite of regulatory actions that will dramatically improve America’s air quality. CAMR directly regulates mercury emissions from coal-fired power plants. Among other things, CAMR requires compliance with a two-phase nationwide cap on mercury emissions. The first phase cap (effective in 2010) is 38 tons per year (“tpy”), and the second phase cap (effective in 2018) is 15 tpy. Once fully implemented, CAMR will result in about a 70 percent reduction in mercury emissions from domestic coal-fired power plants, which is a reduction from a 1999 baseline of 48 tons.”


Within Minnesota, the Mercury Emissions Reduction Act of 2006 lays out the specific details for the Sherco power facility and how it is to comply with the Hg reduction actions. The act allows utilities to recover capital and operating costs of such an effort. A recent report entitled “Review of Xcel Energy’s Sherco Units 1 and 2 Mercury Reduction Plan” from the Minnesota Pollution Control Agency (MPCA), stated, “On December 21, 2010, Xcel Energy (Xcel) submitted an emission reduction proposal, the Mercury Control Plan for its Sherburne County Generating Plant (Sherco) Units 1 and 2, pursuant to Minn. Stat. § 216B.682.1 Xcel proposes to operate powdered activated carbon sorbent injection by the statutory deadline of December 31, 2014.”
The report goes on to discuss the technology selection and annual operating and capital recovery costs calculated on a per lb. of Hg on an annualized basis. Specifically, in the report the MPCA describes the total annual costs of the control technologies, which include chemical purchase, labor and capital recovery. The cost per pound of mercury removed decreases with the improvement in mercury removal. The analysis shows that the use of activated carbon injection (PAC – Powered Activated Carbon) results in the lowest cost per pound of mercury removed at $33,470 /lb Hg removed on an annual basis. Based on this assessment our economic model assumes that for each pound of Hg reduction realized through the co-firing of biocoal provides $33,470 in cost avoidance to Xcel Energy, thereby effectively lowering the cost of the biocoal fuel.

We realize the above assumption is not theoretically accurate as the capital installation of a PAC system is a onetime charge allocated out to actual Hg emission reductions. However, it is the best surrogate for the implied costs of Hg removal for a utility such as Xcel Energy’s Sherco power plant that we realistically have access to.

The average United States coal has 7.3 lbs Hg / trillion btu or approximately 0.2 lbs of Hg per short ton of coal used at pulverized coal power plants. For the Sherco system since it is using a Southern Wyoming Powder River Basin coal we again use the Coal Market Module assumptions as a means to triangulate our calculation of 4.08 E-05 lbs of Hg / MWh (2009 Data) for the Sherco system (Units 1 – 3 Average). The biocoal used in our demonstration runs had an average concentration of Hg of 3.17 lbs. Hg / trillion btu. Therefore, as co-firing ratios of biocoal to coal increase on a btu basis, the relative level of Hg emissions will drop.

Particulate Matter or “PM” is also a regulated emission from traditional coal powered power plants. Due to the technical specifics of how PM is determined in real flue gas streams, our analysis of how biocoal co-firing impacts (positive or negative) PM emissions in any of the combustion / gasification systems was beyond the scope of this demonstration project. Specifically, in order to determine PM emissions – and more specifically PM2.5 – emissions accurately many hours of steady state operations are required of which we simply did not have enough biocoal fuel to accommodate such tests.

(12) Renewable Power: REC’s

In support of renewable power generation, regionally, we have seen REC (Renewable Energy Credit) trading systems develop such as the M-RETS (Midwest Renewable Energy Tracking System) platform here in the Midwest United States. These systems allow for the verification of one MWh generated from a renewable source to be tracked within the electrical grid from the generation source to final sale of the power.

According to an October 2010 survey conducted by Bloomberg New Energy Finance for the REC Markets 12 respondents within the M-RETS service area responded as to price expectations for REC’s within the 2013 – 2020 timeframe. Fifty percent (50%) of respondents indicated they thought that REC prices would average between $0 - $5 per MWh of certified production. Thirty-three (33%) of respondents indicated they thoughts REC prices would average between $5-$20 per MWh of certified production. Combined, this represents 83% of the survey respondents and the most conservative perspective on the topic. As a conservative input, we averaged the value of the majority of REC survey respondents to choose $2.50 / MWh as our baseline economic model input.
Emission Reduction Scenario Analysis:

Using the baseline model inputs as described above, and only changing co-firing ratio from 10- 30%, a set of emission reduction estimates were determined using the economic analysis model. The following two tables lay out the estimated emissions and estimated emissions reductions at Sherco Unit 1 when co-firing at 0% (2009 Emission Rates), 10% and 30% ratios of biocoal to coal on a btu basis. The model inputs were all set to the baseline as provided in Figure 4: Baseline Economic Model Inputs. The only variable that changes between the two scenarios is the co-firing percentage from 10% to 30%. It should be noted that the analysis assumes operating expenses and performance attributes of the Sherco Unit 1 would remain unchanged from 0% co-firing to 30% co-firing.

<table>
<thead>
<tr>
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<th>Estimated Annual Emission Reductions: 10% Biocoal Co-Firing – BTU Basis (Sherco Unit 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CO₂</strong></td>
<td>Estimated CO₂ Emissions (tons) - 2009 Emission Rates</td>
</tr>
<tr>
<td></td>
<td>4,673,731</td>
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<td></td>
<td>Estimated Annual Reduction in CO₂ Emissions (tons)</td>
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<td>480,464</td>
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<td>Estimated Annual Co-Firing Net CO₂ Emissions (tons)</td>
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<td>4,193,267</td>
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<tr>
<td></td>
<td>Estimated Annual Reduction in CO₂ Emissions (%)</td>
</tr>
<tr>
<td></td>
<td>10.3%</td>
</tr>
</tbody>
</table>

| **SO₂**       | Estimated Baseline SO₂ Emissions (tons) - 2009 Emission Rates                               |
|               | 6,815                                                                                       |
|               | Estimated Annual Reduction in SO₂ Emissions (tons)                                         |
|               | 1,074                                                                                       |
|               | Estimated Annual Co-Firing SO₂ Emissions (tons)                                             |
|               | 5,742                                                                                       |
|               | Estimated Annual Reduction in SO₂ Emissions (%)                                             |
|               | 15.8%                                                                                       |

| **NOₓ**       | Estimated Baseline NOₓ Emissions (tons) - 2009 Emission Rates                              |
|               | 3,941                                                                                       |
|               | Estimated Annual Reduction in NOₓ Emissions (tons)                                         |
|               | 668                                                                                         |
|               | Estimated Annual Co-Firing NOₓ Emissions (tons)                                            |
|               | 3,273                                                                                       |
|               | Estimated Annual Reduction in NOₓ Emissions (%)                                             |
|               | 17.0%                                                                                       |

| **Hg**        | Estimated Baseline Hg Emissions (lbs.) - 2009 Emission Rates                               |
|               | 177.7                                                                                       |
|               | Estimated Annual Hg Emissions from Coal - Co-Firing (lbs.)                                |
|               | 159.9                                                                                       |
|               | Estimated Annual Hg Emissions from Biocoal - Co-Firing (lbs.)                             |
|               | 8.6                                                                                         |
|               | Estimated Annual Reduction in Hg Emissions (lbs.)                                          |
|               | 9.2                                                                                         |
|               | Estimated Annual Co-Firing Hg Emissions (lbs.)                                             |
|               | 168.5                                                                                       |
|               | Estimated Annual Reduction in Hg Emissions (%)                                              |
|               | 5.2%                                                                                       |

<table>
<thead>
<tr>
<th></th>
<th>Estimated Annual Emission Reductions: 30% Biocoal Co-Firing – BTU Basis (Sherco Unit 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CO₂</strong></td>
<td>Estimated CO₂ Emissions (tons) - 2009 Emission Rates</td>
</tr>
<tr>
<td></td>
<td>4,673,731</td>
</tr>
<tr>
<td></td>
<td>Estimated Annual Reduction in CO₂ Emissions (tons)</td>
</tr>
<tr>
<td></td>
<td>1,441,391</td>
</tr>
<tr>
<td></td>
<td>Estimated Annual Co-Firing Net CO₂ Emissions (tons)</td>
</tr>
<tr>
<td></td>
<td>3,232,340</td>
</tr>
</tbody>
</table>
### Economic Model Sensitivity Analysis:

Another key output from the demonstration was to determine the impact to average electrical power customers should co-firing of biocoal with fossil coal at existing pulverized coal power plants prove feasible. Using the economic model created during the demonstration, a set of baseline inputs were developed and explained as shown in Figure 4: Baseline Economic Model Inputs. Then, to determine the relative impact of each input variable on the key outputs of the model a sensitivity analysis table was generated and a set of results were calculated within the economic model using these model inputs.

Using the Xcel Energy 2010 10-K filed with the SEC, we calculate that the average residential electricity customer bill in the last fiscal cycle was approximately $902.29 for the entire year. By understanding how the price of delivered electricity might change (%) under a variety of economic model inputs, it was then possible to determine the financial impact to average residential electricity customers as a result of co-firing at 10% and 30% biocoal at Sherco Unit 1. The results of this are also included in the sensitivity analysis charts below.

Within the sensitivity analysis of the estimated increase in cost to average Xcel electrical customers, we broke out the results in two basic ways. The first, which we call “Isolated,” estimates the new price of electricity for the average Xcel customer assuming that the only power plant that Xcel owns and operates is the Sherco Unit 1, and that all the possible price increases from using the biocoal fuel at this plant would be allocated to the electricity coming from this plant to customers. In the second, which we call “Network Wide,” we estimate the new price of electricity for the average Xcel customer assuming that the possible increase in price of electrical power generated at Sherco Unit 1 from co-firing is a weighted average of the

<table>
<thead>
<tr>
<th>Emission</th>
<th>Estimated Baseline (tons) - 2009 Emission Rates</th>
<th>Estimated Annual Reduction in Emissions (tons)</th>
<th>Estimated Annual Co-Firing Emissions (tons)</th>
<th>Estimated Annual Reduction in Emissions (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>6,815</td>
<td>1,937</td>
<td>4,878</td>
<td>28.4%</td>
</tr>
<tr>
<td>NOₓ</td>
<td>3,941</td>
<td>1,181</td>
<td>2,761</td>
<td>30.0%</td>
</tr>
<tr>
<td>Hg</td>
<td>177.7</td>
<td>124.4</td>
<td>25.7</td>
<td>15.6%</td>
</tr>
</tbody>
</table>

---

**Public Information**
entire electric power generation portfolio within the entire Xcel Network. Essentially, in the Network scenario the additional costs from co-firing biocoal are allocated out to all Xcel Energy electrical customers on a weighted average basis.

The key model inputs are provided below (1 – 12) and also indicated on Figure 4: Baseline Economic Model Inputs. While there are many other inputs that can be changed in this model, only those inputs that were viewed to have the greatest impact for this discussion were included. Then, to determine their relative impact on the delivered cost of electricity to the average Xcel Energy customer these model inputs were varied by +20% to -20% in 10% increments from the Baseline to determine the relative impact on the price, change, or annual impact of electricity at 10% and 30% co-firing ratios in both Isolated and Network Wide model assumptions. The below figure lays out the model input baselines and their corresponding sensitivity change inputs to generate the resulting graphs.

Co-Firing Sensitivity Analysis Economic Model Input Table

<table>
<thead>
<tr>
<th>Negative</th>
<th>Baseline</th>
<th>Positive</th>
</tr>
</thead>
<tbody>
<tr>
<td>-20%</td>
<td>-10%</td>
<td>0%</td>
</tr>
<tr>
<td>Biomass Price ($/ton) (1)</td>
<td>$57.90</td>
<td>$65.14</td>
</tr>
<tr>
<td>Biomass Moisture (%) (2)</td>
<td>13.6%</td>
<td>15.3%</td>
</tr>
<tr>
<td>Natural Gas ($/mmbtu) (3)</td>
<td>$3.50</td>
<td>$3.94</td>
</tr>
<tr>
<td>Coal Delivered ($/mmbtu) (4)</td>
<td>$1.51</td>
<td>$1.70</td>
</tr>
<tr>
<td>Debt Interest Rate (%) (5)</td>
<td>5.6%</td>
<td>6.3%</td>
</tr>
<tr>
<td>Equity Required Rate (%) (6)</td>
<td>12.0%</td>
<td>13.5%</td>
</tr>
<tr>
<td>Biocoal Plant (M $USD) (7)</td>
<td>$25.03</td>
<td>$28.15</td>
</tr>
<tr>
<td>CO₂ Value ($/MT) (8)</td>
<td>$1.60</td>
<td>$1.80</td>
</tr>
<tr>
<td>SO₂ Value ($/ton) (9)</td>
<td>$13.27</td>
<td>$14.93</td>
</tr>
<tr>
<td>NOₓ Value ($/ton) (10)</td>
<td>$36.02</td>
<td>$40.53</td>
</tr>
<tr>
<td>Hg Abatement ($/lb.) (11)</td>
<td>$26,776</td>
<td>$30,123</td>
</tr>
<tr>
<td>REC Value ($/MWh) (12)</td>
<td>$2.00</td>
<td>$2.25</td>
</tr>
</tbody>
</table>

Figure 8: Model Input Sensitivity Chart

It should be noted that the use of the term “baseline” has two meanings in the context of the following discussion. The first meaning of the word “Baseline” is without co-firing, or the “Baseline” of the emissions and cost of electricity without any co-firing at the Sherco Unit 1 pulverized coal power plant. The second meaning of the word “Baseline” is the starting or “baseline” model inputs for each of the variables from which they are subsequently varied by + to -20% from this baseline for the sensitivity analysis tables.

The resulting tables were generated by changing one model input variable at a time and then ensuring that all other model inputs were at their baseline. The results are for both 10% and 30% co-firing ratios for both the Network Wide and Isolated assumptions. We calculated the average price of electricity ($/kwh), the percentage change in the price of electricity, and the estimated annual increase for the average residential electricity customer within the Xcel Energy network.
Sensitivity Analysis: 10% Co-Firing Ratio Sherco Unit 1 (Network Wide):
Average Price of Electricity ($/kwh) vs. Percentage Change in Economic Model Input Variables from the Baseline

Sensitivity Analysis: 30% Co-Firing Ratio Sherco Unit 1 (Network Wide):
Average Price of Electricity ($/kwh) vs. Percentage Change in Economic Model Input Variables from the Baseline
Sensitivity Analysis: 10% Co-Firing Ratio Sherco Unit 1 (Network Wide):
Percentage in Electricity Price Change vs.
Percentage Change in Economic Model Input Variables from the Baseline

Sensitivity Analysis: 30% Co-Firing Ratio Sherco Unit 1 (Network Wide):
Percentage in Electricity Price Change vs.
Percentage Change in Economic Model Input Variables from the Baseline
Sensitivity Analysis: 10% Co-Firing Ratio Sherco Unit 1 (Network Wide):
Annual Increase in Electric Bills for Average Residential Customers vs.
Percentage Change in Economic Model Input Variables from the Baseline

Sensitivity Analysis: 30% Co-Firing Ratio Sherco Unit 1 (Network Wide):
Annual Increase in Electric Bills for Average Residential Customers vs.
Percentage Change in Economic Model Input Variables from the Baseline
Sensitivity Analysis: 10% Co-Firing Ratio Sherco Unit 1 (Isolated):
Average Price of Electricity ($/kwh) vs. Percentage Change in
Economic Model Input Variables from the Baseline

Average Price of Electricity ($/kwh)

Sensitivity Analysis: 30% Co-Firing Ratio Sherco Unit 1 (Isolated):
Average Price of Electricity ($/kwh) vs. Percentage Change in
Economic Model Input Variables from the Baseline

Average Price of Electricity ($/kwh)
Sensitivity Analysis: 10% Co-Firing Ratio Sherco Unit 1 (Isolated):
Annual Increase in Electric Bills for Average Residential Customers vs.
Percentage Change in Economic Model Input Variables from the Baseline

Economic Model Input Variables

Sensitivity Analysis: 30% Co-Firing Ratio Sherco Unit 1 (Isolated):
Annual Increase in Electric Bills for Average Residential Customers vs.
Percentage Change in Economic Model Input Variables from the Baseline

Economic Model Input Variables
Regional Economic Impact:

The regional economic impact from co-firing at 10% and 30% ratios at the Sherco Unit 1 would be real and fairly substantial.

Within the 10% co-firing scenario at Sherco Unit 1, two (2) 150,000 ton / year biocoal production plants would be needed. At $31.28 million dollars each, these projects would add jobs from construction, financing, and equipment suppliers. Once completed, each plant would hire approximately 15 full-time positions and purchase 275,284 tons of raw biomass from regional suppliers on an annual basis. The highlights of the 10% co-firing scenario are provided below:

- Total Investment: $62.56 million – debt and equity
- Total Annual Payments to Minnesota Biomass Suppliers: $39.85 million
- Total Direct Full Time Jobs Created: 30+
- Total Indirect Jobs Created: 30+ (Biomass Harvesting, Biomass Transport, Biocoal Transport)
- Total Annual CO₂ Emissions Avoided: 480,464 tons CO₂
- Total Annual 100% Renewable Power Generated: 435,495 MWh (Enough for 50,338 Homes)
- Estimated Annual Increase in Average Xcel Residential Electric Customer Bill: $3.30 (Network)
- Estimated Average Price of Electricity for Xcel Customers: $0.07740 (Network)
- Estimated Increase in Price of Average Electricity: 0.37% (Network)

Within the 30% co-firing scenario at Sherco Unit 1 just over five (5) 150,000 ton / year biocoal production plants would be required. At $31.28 million dollars each, these projects would add jobs from construction, financing, and equipment suppliers. Once completed, each plant would hire approximately 15 full-time positions and purchase 275,284 tons of raw biomass from regional suppliers on an annual basis. The highlights of the 30% co-firing scenario are provided below:

- Total Investment: $156.4 million – debt and equity
- Total Annual Payments to Minnesota Biomass Suppliers: $103.2 million
- Total Direct Full Time Jobs Created: 75+
- Total Indirect Jobs Created: 75+ (Biomass Harvesting, Biomass Transport, Biocoal Transport)
- Total Annual CO₂ Emissions Avoided: 1,441,391 tons CO₂
- Total Annual 100% Renewable Power Generated: 1,306,485 MWh (Enough for 151,015 Homes)
- Estimated Annual Increase in Average Xcel Residential Electric Customer Bill: $9.90 (Network)
- Estimated Average Price of Electricity for Xcel Customers: $0.07797 (Network)
- Estimated Increase in Price of Average Electricity: 1.10% (Network)

Economic Analysis:

With the economic model completed and the baseline model inputs entered, we were then able to determine the impact on the price of electricity to the average Xcel Energy customer. The average Xcel residential customer would see their individual annual electric bill increase by only $3.30 or only $0.275 per month for a 10% co-firing ratio. At 30%, the average Xcel residential customer would see a $9.90 per year increase.
However, if Xcel were to co-fire 10% of all of its coal-powered pulverized coal power plants, the average residential electrical customer would see their electric bill increase $82.99 per year ($6.92 / month), a 9.2% increase at the 10% co-firing ratio, or an increase of $249.12 per year ($20.76 / month), a 27.6% increase, at the 30% co-firing ratio.

One benchmark is the Retail Renewable Energy Certificates (REC) offerings available to residential customers on a national level. Of particular interest is Green Mountain’s offering of biomass derived energy with a residential premium of 1.4¢ per kwh. When looking at the financial impact of the cost of electricity provided to the average user within the Xcel network under a 10% co-firing scenario at Sherco Unit 1, one would go from the average 2010 price of 7.712¢ per kwh to 7.740¢ per kwh – or a 0.028¢ premium. However, this is a weighted average cost. If the cost of the biocoal fuel were 100% allocated to only the renewable energy produced to create a REC, the cost of electricity for the REC would be $0.153577 or 15.3577¢ per kwh due to the $0.07113 / kwh increase (7.113¢ per kwh) in the cost of fuel over that of traditional coals.

When looking at regulatory drivers which might incentivize such biocoal co-firing activity, one can look to the price of CO2 when traded on such previously discussed exchanges. We now look at what the price per emitted ton of CO2 would need to be given the baseline assumptions for 10% and 30% co-firing ratios to be a breakeven proposition for utilities such as Xcel Energy and the use of biocoal at Sherco Unit 1. For the baseline scenarios (10% and 30% co-firing ratios) the price per emitted ton of CO2 will need to be $66.29 to allow Xcel to produce electricity at the same net cost with biocoal as with traditional coal.

When looking at the weighted average increase in the cost of delivering electricity at the 10% co-firing ratio across the entire Xcel portfolio, we note that the relative increase in cost is only 9.2% or a 0.0071 increase per kwh of electricity consumed. When looking at the cost of delivering electricity at the 30% co-firing ratio across the entire Xcel portfolio, we see a relative increase in cost of 27.61% or a 0.0229 increase per kwh of electricity consumed.

While these might seem like relatively large percentage increases in price for electricity, we need only look to a recent experiment undertaken by the city of Boulder, Colorado, which passed what appears to be the first municipal ‘carbon tax’ specifically aimed at reducing carbon emission to those outlined in the Kyoto Protocol – 7% emission reductions below 1990 levels by 2012. As of 2010, the tax is set at $0.0049 / kwh for residential users, $0.0009 / kwh for commercial, and $0.0003 / kwh for industrial. Looking at our $0.0071 which reduces emissions by approximately 10%, a rough approximation of our proposed co-firing at a 7% ratio (Kyoto) would create an increase of $0.00497 / kwh, which is essentially the same as the tax currently being paid by Xcel Energy in Boulder right now.

**Project Benefits:**

Several of the main project benefits that were developed and demonstrated from this project were as follows:

- Improved the bulk energy density of raw corn stover by over 37 times allowing the product to be more cost effectively transported over long distances, stored more economically and used in a wider variety of existing combustion systems for heat, power or snygas production.
• Developed a product that shows promise to leverage existing bulk commodity transportation infrastructure at rail yards and other high volume commodity intermodal transport hubs.
• Produced a product from raw biomass that can be handled by existing belt conveyors, and other bulk feed handling systems of which raw biomass in bulk form is typically not suitable.
• Produced a product which is highly resistant to water absorption, or hydrophobic, which dramatically improves the biomass’ ability to be stored and transported using existing infrastructure.
• Produced a product which is highly versatile and shown in early pilot tests to be suitable for the production of renewable baseload electricity using existing infrastructure, the production of steam and heat in stoker grates for district heating and/or other distributed heating systems, and the production of renewable syngas using gasification systems such as updraft, downdraft and potentially high pressure entrained flow systems.

Rural Minnesota generates significant economic activity, with a significant portion of its economy in the agricultural sector. One of the aims of the project was to determine how to increase the value of existing agricultural practices by demonstrating and piloting the collection and processing of corn stover from existing farmland in Minnesota. One of the barriers that the project worked to overcome was the inherent low bulk and energy density of corn stover solid fuel as it comes off the field. This low bulk and energy density is a barrier to efficient storage, transportation and use in existing pulverized coal power plants for the generation of baseload renewable electricity.

One main project benefit was the ability to demonstrate that corn stover can be collected and processed to increase the bulk energy density of raw corn stover coming off the field to a torrefied and briquetted product, or “biocoal,” by over 37 times. The energy density of one cubic foot of raw corn stover coming off the field during harvesting in the Fall of 2008 averaged 9,178 btu/ft³. We saw bulk densities of 1.8 lb/ft³ with an average moisture content of 35% (MS2) and on-field, as-received energy densities averaged 5,099 btu/lb. After our process, the as received energy density was 8,568 btu/lb at 40 lbs/ft³, which equates to 342,720 btu/ft³. This is a 37.3 fold increase in the as-received bulk energy density from the raw feedstock to the finished product. The project proved the technical feasibility of converting raw biomass into a hard, durable and energy dense product, or “biocoal,” that could be used by existing pulverized coal power plants to produce baseload renewable electricity.

Another main project benefit was the ability to demonstrate that the resultant biocoal product, while having an improved bulk energy density, is also compatible with existing bulk handling transportation and storage infrastructure. Unlike raw biomass which is not flowable, has a propensity to rot, and readily absorbs moisture, the resultant biocoal product produced as a result of this project showed in early pilot studies to have similar bulk handling, flowability, hydrophobicity, and durability characteristics of typical steam coals (sub-bituminous) used throughout North America. This improved material handling capability imparted on the raw biomass as a direct result of the developed biomass torrefaction and densification process is a significant contribution to the overall supply chain and end user economics thereby driving easier widespread adoption of this form of renewable energy.

*So, technically speaking the project created benefits by increasing our knowledge of the technical feasibility of converting raw biomass into biocoal, but what about the economics of the conversion process?*
The project showed that an increase of only $0.008 per kwh would allow the proposed process to be economically indifferent to electricity power producers within Minnesota when using a 10% co-firing blend of biocoal made of corn stover with 90% coal, using existing pulverized coal power plants. This represents a 9.9% average increase in electricity prices from today. Said another way, if the cost assignable to every ton of carbon dioxide emitted were priced at approximately $6.93 per ton, existing electricity power producers would be indifferent between using 100% coal or using a 90% coal to 10% biocoal blend on a purely economic basis. The project provided a benefit by determining with a high level of accuracy the true costs of such a renewable solid fuel conversion for existing electricity power producers and their respective customers.

So we know now that the process is technically feasible, economically within reach, but what kind of real impact could this have within Minnesota for both power producers, rural economies, and residential electricity users?

Rural Minnesota:
According to the USDA’s National Agricultural Statistics Service (NASS), Minnesota planted approximately 8.1 million acres of corn for grain and silage in 2011. At the average of 2.0 dry tons per acre of harvest, as seen in our project’s Fall 2008 harvest, this equates to a total sustainable stover harvest capacity of 16.2 million tons of corn stover. Using the project’s estimate of $72.38 per ton delivered to a biocoal production plant, this represents a potential $1.17 B economic impact to the rural economies of Minnesota, assuming all of the corn stover was to be moved through this process. While the $72.38 is divided among nutrient replacement, tipping fees, timeliness costs, fuel, and transportation, etc., the impact to the rural economy of Minnesota would be undeniable if such a commercial process were to take hold at an appreciable scale.

Residential Electricity Users:
At 16.2 million tons annually, that’s enough energy, after the torrefaction and densification technology developed in this project, to co-fire the product with coal to produce 10% baseload renewable electricity for 6 million average residential homes – or 5,200 GWh or electricity. While economic and technical hurdles remain to commercialize the process technology at the scale required to realize this potential an increase of only $0.008 per kwh (9.9% increase) or an annual average increase for a residential customer of $89.45 would allow the economics to be viable for today’s electricity power generators. Said another way, if the cost assignable to every ton of carbon dioxide emitted were priced at approximately $6.93 per ton existing electricity power producers would be indifferent between using 100% coal or using a 90% coal to 10% biocoal blend on a purely economic basis.

Power Producers:
With well over a 1,000 coal powered facilities (electricity, heat, etc.) throughout the United States the ability to produce a renewable product which is compatible in nearly every way to existing fossil coals opens up a direct drop-in replacement for utilities to easily produce renewable energy using existing infrastructure. The project developed and demonstrated the production of a renewable biomass solid fuel that shows promise to be a direct drop-in replacement for coal.

With the project’s “biocoal” product, we were able to show that the upgraded biomass product has a similar hardgrov grinadiablity index, energy density, bulk density, durability, material handling, and hydrophobic characteristics to that of existing fossil fuel coal energy sources. With these similarities, the biocoal product can be directly substituted for coal in existing power infrastructure throughout the country with minimal need for existing power producers to expend additional capital for on-site material handling, grinding, or
other systems typically required when co-firing raw biomass. The use of biocoal at existing coal-powered facilities to reduce the system’s net carbon intensity would be dispatchable, and would allow power producers to avoid spending new capital for on-site improvements and additions to their existing infrastructure. The use of biocoal for the production of renewable energy would be a capital avoidance strategy for power producers to meet their existing or pending regulatory mandates while using existing infrastructure.

With regulatory uncertainty casting a shadow on where to most effectively deploy capital to either maintain or expand your baseload or peaking electricity generation capacity, the ability to add deployable solid fuel that uses existing infrastructure to produce baseload renewable electric power provides an interesting option to consider. However, typical “biomass” feedstocks suitable for use in combustion systems are low in bulk and energy density, have a propensity to rot and are difficult to grind to the particle size required for use in existing pulverized coal power plants. The project proved the feasibility of producing and using torrefied and densified corn stover “biocoal” in pulverized coal boilers to produce renewable baseload electricity. The resulting “biocoal” product was proven to have over 37 times more bulk energy density than raw corn stover, grind more easily than corn stover, and dramatically improved the products transportability and storage capabilities through increases in bulk density, crush strength, durability, and hydrophobicity.

Additionally, using a biocoal strategy to augment existing and/or other regulatory mitigation efforts – such as wind and solar – a power producer could purchase long term contract options on biocoal production and utilize the biocoal when electricity and carbon pricing are justified without changing their asset base. In regulated environments, typically electricity power producers are constrained from raising rates until moved through a rate case. However, using a Green Power Pricing model to allow individual consumers to “opt” in to “green” power provides a means for electricity generators to produce green power and get paid for it. However, this can cause some level of uncertainty as the production of green power typically requires the deployment of new capital with long-lived asset life without the ability to control the inevitable fluctuation in “opt-in” green power demand. The use of a biocoal strategy for a green power pricing model for electricity utilities allows the utility to produce green power only when it is demanded while using existing infrastructure. The Project effort has concluded that a pulverized coal electricity producer would need to charge a residential consumer a $0.0765 green power premium for 100% renewable power produced from corn stover biocoal.

**Project Lessons Learned:**

Commodity pricing (natural gas) causes swings in the economic viability of long-lived assets. On the onset of the project the price of natural gas was approaching $8.00 / mmbtu whereas our anticipated costs of raw biomass were around $2.20 / mmbtu. These economic pricing signals have switched places over the last several years with natural gas hovering around $4.00 whereas the price of biomass in our project penciled out to be $9.28 / mmbtu.

The cost of the raw feedstock, corn stover, was twice the originally expected price at $72.38 vs. a pre-project estimate of $35. Further, the price of the raw biomass feedstock dominates the delivered biocoal costs to electricity power generators. The project team calculated the production costs of $17.64 per processed ton – not including the raw biomass. However, while corn stover pricing currently remains outside of the economic window for overall supply chain viability, the project proved the developed process and end
product can be applied to a wide variety of raw biomass types such as sugarcane bagasse and other wood species, with the end product quality varying with each feedstock. The feedstock flexibility shown in the biomass torrefaction and densification pilot facility developed within this project opens the doors to explore other feedstocks of opportunity to help mitigate higher cost feedstocks.

As feedstock into the system changes, so too will the system need to be adapted to accommodate the feedstock. However, if the raw biomass feedstocks can be economically reduced to a similar particle size and resulting bulk density the only characteristics of the system that would likely need to change would be the time and temperature at which the torrefaction of the biomass would occur. In supply chains that have dramatically different raw biomass feedstocks – for example, ground corn stover and wood chips – the feed handling and reactor designs for these two different feedstocks would likely be designed differently to incorporate the changes to the system dynamics imposed by these different feedstocks.

The production conversions costs from raw corn stover to biocoal were determined to be just a fraction of the final costs. Therefore, the acquisition and control of large volumes of raw biomass at economically advantageous prices will be of paramount importance when putting together project financing for any eventual commercial scale biocoal production plant. The owners of the biocoal production plants would likely be best suited to be large forestry companies, large farms, or other dedicated energy crop producers, or aggregators.

While in-field collection of the raw corn stover biomass was, overall, successful further improvements of in-field density and post-collection storage are still required to further optimize the entire biomass supply chain for the eventual production of commercial quantities of a biocoal product from corn stover.

The physical volume of corn stover required for economically interesting quantities of biocoal to be produced are quite staggering. At 1.8 lbs/ft^3 of in-field densities, as seen by our Fall 2008 harvest, annual collection of all of the sustainably harvested corn stover in Minnesota could fill up the entire interior volume of the Twin Cities Metrodome 462 times.

The current state of the art of raw biomass size reduction, while advanced, likely needs to develop specialized equipment to accommodate round or square bales at rates in excess of three to four times that existing “large” raw biomass machines are currently capable of, assuming the bales are shipped to the biocoal plant as is.

The in-field and hybrid variation of raw biomass feedstock causes variability within the biomass torrefaction and densification production process that will likely need to be actively managed to better ensure consistent “biocoal” product should the process move into a commercial setting.

As the natural variability of raw biomass moves through the biomass torrefaction and densification system, so too will the variability of the final product. The project proved the technical ability to densify corn stover into biocoal. As the raw biomass input into the system changed substantially, such as from a different field, year of harvest, alternative storage method or hybrid, we would see changes in the resulting characteristics of the finished product. Just as with an industrial chemical process feedstock consistency is key to keep the finished product characteristics consistent. Eventual commercial scale systems will need to factor this inevitable variability in raw biomass feedstock into the design and operational window of the installed plant.
While the resulting biocoal proved to be significantly superior to raw biomass with regard to moisture-uptake and resistance to rotting, the extent to which the product can be stored outdoors using the exact same storage methods as coal were not conclusive. Further testing of these attributes should be conducted prior to commercially viable quantities of biocoal are contracted for at existing pulverized coal power plants.

The use of corn stover biocoal proved to be technical feasible at existing pulverized coal power plants to produce electricity. However, due to the elevated levels of alkaline earth metals within the ash of corn stover the fuel’s propensity to accelerate the rate of fouling depositions will need to be carefully reviewed by specific potential users of the fuel for appropriate blending rates, boiler settings, and/or possible additives to reduce the impacts.

Usefulness of Project Findings:

As we started this project we set out with three main goals:

- **Goal 1:** Generate electricity from the torrefaction of renewable biomass energy sources that are readily available in Minnesota and approaching economic feasibility
- **Goal 2:** Strengthen the economy of rural Minnesota through value-added processes that capture renewable biomass energy production capability
- **Goal 3:** Increase accessibility to information that facilitates the adoption of biomass technologies to generate electricity and reduce fossil fuel use

The project findings have proven the technical feasibility and have demonstrated and developed the key knowledge required to pursue larger scale trials and eventual commercial implementation of the developed technology. When fully implemented on a commercial basis, the underlying process and foundation laid by this product will allow the generation of electricity from the torrefaction of renewable biomass energy, and as a result, will strengthen the economy of rural Minnesota by capturing additional value from the renewable biomass.

By accomplishing goal three we have laid a solid foundation from which future piloting and larger scale demonstration projects can be funded to move the concept further towards commercial implementation. Further, by developing a solid understanding as to the overall economics of the proposed system – from field to combustion – we have developed and communicated the boundary conditions under which such a system would be economically viable and/or what the current costs would be for existing power producers to implement the system on a commercial basis – be that raw biomass prices, coal prices, electricity prices, regulations or a price levied on carbon dioxide emissions – the information generated from this project sheds further light as to when, economically, the process can gain commercial traction in today’s energy markets.

The project proved that the torrefaction process increases the ability of biomass to be transported, stored, and utilized in today’s pulverized coal power plants over that of raw biomass. While the project focused on corn stover the project also proved that the process is transferrable to other raw biomass feedstocks such as sugarcane bagasse, wood, etc. The broad application of the process on raw biomass feedstocks to improve their functionality and usability in existing infrastructure to produce renewable energy should not be understated. For example, using torrefaction as a pre-treatment option just ahead of a IGCC system for cofiring with coal or the pre-treatment of raw biomass for a BTL (biomass to liquids) gasification system –
such as a high pressure entrained flow gasification system for the production of fuels or chemicals via a Fischer–Tropsch (FT) synthesis process – are other high value applications of the base technology developed within this project.

The project has also provided useful findings in that, if implemented on a commercial basis, the torrefaction process proposed by this project would fully realize goal two – in that rural areas, the technology would create skilled, high paying jobs to manage and operate this technology, provide significant economic benefits to these communities, while at the same time reduce the nation’s dependence on fossil fuels and increase its use of renewable energy sources.

Further, by the early flexibility shown by the pilot system developed within this project for different feedstocks, the ability of rural Minnesota to leverage the process technology developed will be expanded to those feedstocks that need to be transported longer distances – such as a Minnesota export to biomass poor areas – as the improvement in bulk and energy density directly resulting from the process developed in this project will dramatically improve the economics of transporting and using the resulting biocoal product in a wide array of end markets. While the project focused on the use of the biocoal product for renewable baseload electric power the biocoal product has also shown flexibility for use in distributed heating, gasification and district heating systems to name a few additional end markets from which the raw biomass can now more easily penetrate.

Milestones:

We have completed all nine of the required nine Milestones.

Project Status:

The project has been successfully completed.

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