CHARITON VALLEY BIOMASS PROJECT

Draft Sales Contract Report

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Chariton Valley Biomass Project (Phase I)
Deliverable 3 –Draft Sales Contract Report

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EXECUTIVE SUMMARY

The Chariton Valley Biomass Project (CVBP) is a research and demonstration effort cost-shared by the U.S. Department of Energy. The primary goal of the Chariton Valley Biomass Project is to demonstrate biomass (switchgrass) and coal cofiring technology with a vision of developing markets for energy crops in southern Iowa. The project is led by Chariton Valley Resource Conservation and Development, a non-profit organization sponsored by the U.S. Department of Agriculture, whose mission is to provide assistance to local communities, counties, and organizations to carry out local objectives related to economic development, community facilities and natural resource conservation. Key partners in the CVBP include: one of the largest energy companies in Iowa (Alliant Energy Corporation), a farmer cooperative organization (Prairie Lands Bio-Products Inc.), southern Iowa farmers, agricultural research staff at Iowa universities, national laboratories, and several engineering and consulting firms with expertise in biomass energy, power generation, and agriculture.

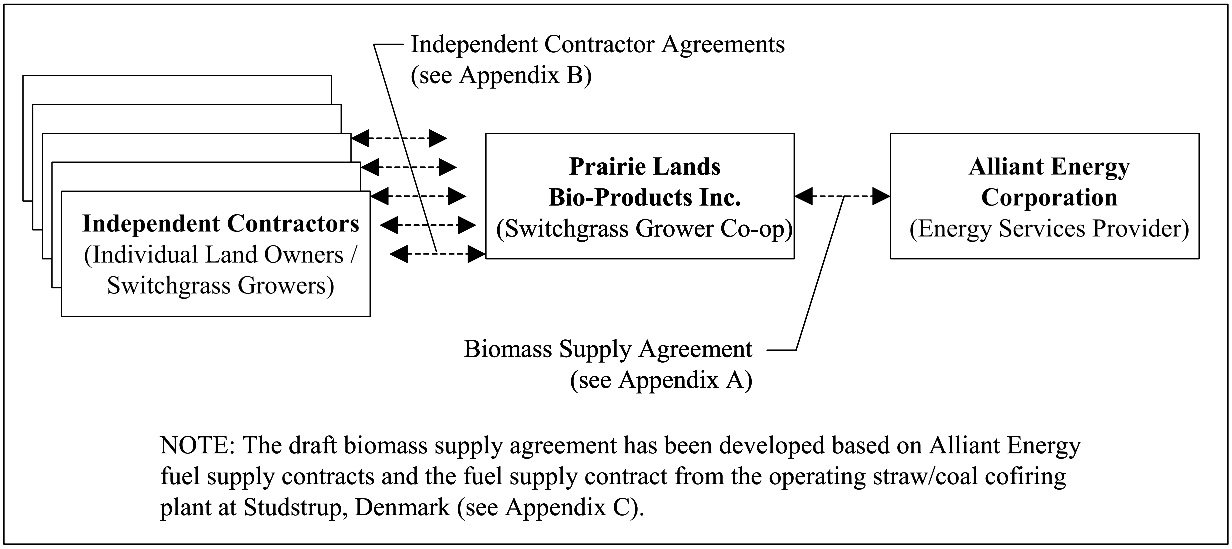
The project seeks to investigate and demonstrate the technical feasibility, environmental benefits, and potential commercial/business viability of growing an "energy crop" (switchgrass) to replace a portion of the coal fuel supply at one of Iowa's largest coal-fired power plants. The project will replace purchases of out-of-state coal with a locally-grown, renewable biomass energy crop. If the project achieves its goal of reaching commercial viability after the research and demonstration phase, it will involve up to 500 southern Iowa farmers growing 200,000 tons per year of switchgrass on up to 50,000 acres for use as fuel for power generation at the 725 mega-watt Ottumwa Generation Station (OGS) in Chillocothe, Iowa. OGS is Iowa's third-largest power plant. The switchgrass will be delivered in bales on trucks to a new biomass storage and processing facility built at OGS. There, it will be de-baled and processed (chopped-up) into a form suitable for use in the power plant's boiler.

This fuel supply contracts report discusses two major elements associated with this effort: 1) a draft biomass fuel supply contract between Alliant Energy Corporation and Prairie Lands Bio-Products Inc., and 2) an economic analysis that assesses the project's commercial viability under likely and possible near-term scenarios. *The economic analysis identifies a number of policy and market scenarios under which the project would be commercially viable.* The report then summarizes the potential need for, and current status of, external factors such as tax credits, emissions credits, renewables mandates or portfolio standards, system benefits charges, green power sales, and the Conservation Reserve Pilot Program. Finally, expected benefits of a commercially-operating Chariton Valley Biomass Project are briefly discussed.

Draft Fuel Supply Contract

Exhibit ES-1 illustrates two planned contractual agreements and the parties involved in a commercially operating Chariton Valley Biomass Project. The three contractual parties are: Alliant Energy Corporation, Prairie Lands Bio-Products Inc., and as many as 500 independent contractors (switchgrass growers). Alliant Energy Corporation is an energy-service provider that serves more than 1.3 million customers in Iowa, Illinois, Minnesota and Wisconsin. Prairie Lands Bio-Products, Inc. is a not-for-profit organization with a current membership of close to 60 switchgrass growers. Prairie Lands' membership elected a board of directors to oversee the organization's activities. Its mission is to: identify and develop switchgrass products and markets for those products, produce switchgrass to satisfy demand for products, evaluate environmental benefits of producing and using switchgrass, and inform and educate the public about the potential of switchgrass. The independent contractors are Southern Iowa farmers who would raise switchgrass on their own lands or land rented from others, and deliver it either directly to the

Exhibit ES-1: Draft Contracting Agreements and Parties for Chariton Valley Biomass Project



switchgrass storage and processing facility at OGS or to intermediate storage facilities in the Chariton Valley Biomass Project area.

To streamline communications for this project, Alliant wants to deal with a single organization (Prairie Lands) rather than with multiple independent contractors as other utilities have done in similar projects. A single "*Biomass Supply Agreement*" between Alliant and Prairie Lands will cover terms and conditions required for delivering processed switchgrass to the burner tips of several burners in the OGS boiler. A draft of this agreement is provided in Appendix A and is briefly summarized in section 2.4 of this report. This draft contract specifies requirements for: biomass quality, delivery terms and schedules, pricing and payment terms, rejection criteria, and warranties and liabilities. It was developed based on existing Alliant Energy fuel supply contracts and the fuel supply contract from the operating straw/coal cofired power plant at Studstrup, Denmark (see Appendix C).

Prairie Lands will coordinate all activities involved in raising, harvesting, storing, delivering, and processing switchgrass and supplying it to the OGS burners. Production, storage and delivery of switchgrass from independent switchgrass growers to Prairie Lands will be handled through "*Independent Contractor Agreements*" between Prairie Lands and each grower/contractor. Appendix B includes a draft of this agreement and key provisions are briefly summarized in section 2.5 of this report.

Costs for Producing and Delivering Switchgrass

Exhibit ES-2 describes a range of possible scenarios for the costs of producing and delivering switchgrass to OGS. These scenarios for switchgrass fuel production, storage, handling and delivery costs to OGS are based on information from a combination of the following sources: Iowa State University reports, Oak Ridge National Laboratory reports, and recent hay market sale prices. The scenarios cited in Exhibit ES-2 cover a wide range of delivered costs that span from the likely minimum to a likely maximum.

Exhibit ES-2: Summary of Switchgrass Delivered Cost Scenarios*

Fuel Delivery Scenario Name	Estimated Ave. Delivered Cost	Scenario Description
"Low"	$40/ton	This is the assumed lowest feasible average annual delivered switchgrass cost. Appendix I shows the range of recent Iowa hay market prices for low-end (fair quality) hay. Auction prices ranged from $40 to $60/ton.
"Low-Medium"	$52/ton	6 ton/acre/yr average yield, a low land charge ($25/acre), all acres get CRP Pilot Program benefits, and low storage costs (storage on crushed stone under re-useable tarps)
"Medium-High"	$68/ton	4 ton/acre/yr average yield, a high land charge ($100/acre), all acres get CRP Pilot Program benefits, and high storage costs (steel sheds)
"High"	$92/ton	4 ton/acre/yr average yield, a high land charge ($100/acre), no CRP Pilot Program benefits, and high storage costs (steel sheds)

* Unless noted otherwise, all tons are implied to be "wet" tons, with moisture content less than 15% by weight. The analyses upon which the costs in the table above were based include typical farmer or farm contractor profit. Iowa State University based its operating costs for farm-related tasks on the *2000 Iowa Custom Rate Survey*, which includes profit for each farm-related task performed.

Based on recent hay market data, the assumed lowest feasible delivery cost was $40/ton ("fair" quality hay was recently sold in Iowa for $40 to $60/ton—see Appendix I for hay market data). Based on estimates from Oak Ridge National Lab, supplies of switchgrass well in excess of 200,000 tons/yr could be produced and delivered in Iowa at this price or lower. According to Oak Ridge's estimates, the statewide quantities that could be available in Iowa at $40 per delivered ton are about *35 times* the 200,000 ton per year amount of switchgrass needed to commercially cofire at OGS.[1] In order to allow the project to reach commercial operation, partners expect that the delivered costs will have to be somewhere in the lower half of the price range indicated in Exhibit ES-2. As the Oak Ridge estimates indicate, and based on project experience and achievable scenarios identified by ISU (even at average yields as low as 4 tons/acre), project partners believe this is possible.

Description of Economic Analysis

An economic analysis model was developed to consider the project's performance under a range of scenarios and to help during possible future contract negotiations. It can be used to identify and quantify the impacts and risks associated with key factors that could influence the commercial viability of the project, including: tax credits, emissions credits, renewables mandates or portfolio standards, system benefits charges, green power sales, the Conservation Reserve Pilot Program, cost of biomass fuel, impacts on ash marketability, biomass system capital costs, and financing terms. Assumptions and details about the analysis are provided in chapter 3.

The cofiring project's economic performance was compared to two primary competitors:

1) *Existing coal-only production costs at OGS*. This represents the status quo condition where no unfulfilled and immediate mandates for increased renewable power generation exist in Iowa.

[1] Walsh, Marie E., et. al., 2000, *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*, Oak Ridge National Laboratory, Oak Ridge, TN, April 30, 1999, Updated January.

2) *Wind power purchased from independent generators from Iowa-based wind farms*. This represents a recent past and potential future situation where Iowa utilities are required to purchase/install and sell increased amounts of renewable power to comply with an expanded renewables mandate or portfolio standard. For this situation, we compared the economic performance of the cofiring project to the likely *range* of prices Alliant would have to pay to purchase more wind generation for Iowa. Wind power is the renewable energy technology with the highest installed generation capacity in Iowa, and is the most likely competition among renewables. The range considered, 2.9 to 4.9 ¢/kWh, accounts for the range of wind conditions available in Iowa and different financing arrangements of the generators, ranging from municipal to independent power producer ownership. The section 45 production tax credit or equivalent[2] was applied for the wind projects in all cases. Based on a detailed recent study on present and future economics of wind generation in Iowa, the average (or most likely) cost of electricity from wind power installed in 2002 in Iowa would be about 3.9 ¢/kWh.[3]

The comparison of the project's economics versus existing electricity production at OGS using coal-only provides a good point of reference based on status quo conditions; however, it is important to note that project's intention has not been to compete with coal but to position biomass use at OGS as a competitively attractive renewable energy source for Alliant to consider (i.e., as opposed to wind).

In determining the cost to produce electricity from switchgrass at OGS, *all operational cost changes at OGS due to the cofiring project were charged to the cofiring project*. For example, if there is a slight decrease in boiler efficiency caused by the cofiring operation, increased coal purchases (per unit of power output) are incorporated into the switchgrass cost of electricity. All changes in ash management costs (if applicable) are fully charged to the cofiring project, although about 95% of the ash will be coal ash during the cofiring operation. Based on assumptions used for this analysis, the bulk of the annual costs associated with the switchgrass portion of the cofiring operation would be:

- Delivered cost of switchgrass fuel
- Fixed O&M costs—This category represents the additional fixed O&M costs that are associated with switchgrass operation. It includes: additional employees, maintenance, administration and insurance to maintain and operate the switchgrass processing and storage facility at OGS.
- Variable O&M costs (exclusive of fuel)—It was assumed that switchgrass power will have the same variable O&M costs on a $/kWh basis as the existing coal-fired operation. This category includes maintenance costs of the boiler, turbines, and other existing equipment at OGS. Based on recent OGS operation, firing 200,000 tons of switchgrass per year would represent 6.2% of the annual heat input required for the boiler, so 6.2% of the estimated variable O&M cost for OGS' existing operations was applied to the cost of generating power from switchgrass.
- Capital and Installation Costs for the Biomass Storage and Processing facility at OGS—This was assumed to be zero in the base case to reflect the proposed Federal cost-sharing that would cover these expenses during the demonstration project.

[2] In the municipal case the Renewable Energy Production Incentive, or REPI, was applied. The REPI incentive is equivalent in value to the section 45 credit and is available to municipal generators.
[3] Wind, Thomas A. (Wind Utility Consulting), 2000, *Projected Impact of a Renewables Portfolio Standard on Iowa's Electricity Prices*, Jefferson, IA, January 31.

- Changes in performance caused by the cofiring operation—This accounts for slight efficiency losses and possible increased fouling on boiler heat exchange surfaces.

The economic analysis tool estimates the delivered switchgrass cost (freight-on-board [F.O.B] delivered in square bales to the switchgrass facility at OGS) required for the project to break even during commercial operation. Under "breakeven" conditions:

- Alliant would capture its normal rate of return on electricity sales from the switchgrass project,
- all operating costs for Prairie Lands would be covered (including all administration, insurance, and biomass processing facility O&M), and
- all operating costs for the farmers would be covered (including all labor, materials, transportation/hauling, storage, land rent, and typical farmer or farm contractor profit)

It should be noted that while much is known about switchgrass production costs, some uncertainty remains regarding the average cost to produce it on a commercial basis at large regional scales for an energy end-use. This has never been done on a commercial basis in the U.S.; therefore, some cost uncertainty exists. In addition, farmers involved in a commercial-scale project will face a wide range of circumstances; each one may have slightly different delivery cost and price requirements, including acceptable profit margins, land value, alternative crops, and equipment needs. From a farmer's perspective, presenting the breakeven prices in terms of delivered cost F.O.B. at the power plant is the most direct comparison to an auction price, which is a very familiar way of valuing crops and judging their relative business benefit. The goal of this analysis, based on the best publicly available information and information not critically sensitive to project partners for future negotiations, is to indicate scenarios under which this project can continue on a commercial basis after the demonstration phase has been completed. The farmers' actual required profit and production costs are very important, business-sensitive items for future contract negotiations.

Economic Analysis—Results and Preliminary Conclusions

Results and conclusions from the preliminary economic analysis are discussed in detail in chapter 4 and are summarized below. Three primary incentives were directly considered in the breakeven analysis: 1) SO_2 emissions credits, 2) the section 45 production tax credit for wind and closed-loop biomass, and 3) green power incentives/premiums.[4] These incentives were chosen for direct consideration because they exist today (although the production tax credit would have to be expanded for it to be used by this project). These incentives are incorporated in the economic model from the electric generation-side of the project (i.e., as if they are incentives collected by Alliant but passed through to the farmers to lower the fuel delivery costs).

[4] Other potential incentives such as systems benefits charges and carbon credits were also considered, but not directly in the economic model.

A fourth incentive is also currently available because the Chariton Valley Biomass Project is one of six pilot biomass energy projects under the Conservation Reserve Program (CRP).[5] Since this is a farm-side incentive, it is reflected in the four potential delivered biomass price scenarios in Exhibit ES-2.

Treatment of green power incentives is based on Alliant's existing Second Nature green power program. Currently, the program has three levels of participation: Nature Sentinel (25% renewable power), Eco Watcher (50% renewable power), and Earth Steward (100% renewable power). The premium for the *renewable portion* of these three products remains fixed at 2.0 ¢/kWh, and the overall premium for each product varies directly according to the fraction of renewable power in the product. If a customer chooses the Earth Steward option, he is charged a 2.0 ¢/kWh premium on all kilowatt-hours purchased. For the 50% renewable product the overall premium to the customer is 1 ¢/kWh (50% x 2 ¢/kWh), and for the 25% renewable product, the overall premium is 0.5 ¢/kWh (25% x 2 ¢/kWh).

Exhibits ES-3 and ES-4 show the results of the preliminary breakeven analysis for the base case scenario. This scenario assumes that there will be no changes in existing ash sales; OGS will be able to receive the same amount of revenue from selling cofired ash as from coal-only ash.[6] The combination of incentives considered for each "scenario" are shown in the left column of each table. Green power incentives (GPI) corresponding to Alliant's three Second Nature product offerings discussed above (25% GPI, 50% GPI, and 100% GPI) are considered in combination with the two other incentives examined (SO_2 emissions credits and the Section 45 production tax credit).

Exhibit ES-3 lists the maximum breakeven price needed for the switchgrass project to compete with coal production costs at OGS (1.5 ¢/kWh), low-cost Iowa wind generation (2.9 ¢/kWh, "wind-low"), average-cost Iowa wind generation (3.9 ¢/kWh, "wind-ave"), and high-cost Iowa wind generation (4.9 ¢/kWh, "wind-high"). As shown in Exhibit ES-3, the GPI does not alter the switchgrass breakeven points for the wind options because this analysis assumes that wind and biomass power will receive equal green power income sources (so neither would gain an advantage over the other due to green power sales). It is also assumed that wind power cannot be cheaper than coal power, so the wind-low entries with 100% GPI are the same as for the coal cases ($38/ton and $62/ton).

Comparing the delivery price scenarios in Exhibit ES-2 to the "required breakeven delivered cost" estimates shown in Exhibits ES-3 allows one to see the farm- and delivery-side conditions

[5] The CRP is a voluntary federal program that offers annual rental payments, incentive payments for certain activities, and cost-share assistance to establish approved cover on eligible cropland. The program encourages farmers to plant long-term resource-conserving covers to improve soil, water, and wildlife resources, and in return, the farmers receive a "rental payment." In the year 2000, the federal government authorized the CRP to conduct pilot projects where biomass would be harvested on CRP land and used for energy production; the farmer would continue to receive a (reduced) rental payment. Under this pilot effort, the farmers still have an incentive to keep the land in the CRP program, but they also have the opportunity to use it to produce a revenue-generating crop. Prior to this pilot project, harvesting on CRP acres was not allowed.

[6] Scenarios examining the effect of negatively impacting existing ash markets at OGS were also considered. If there was a total loss of ash sales due to the cofired ash not meeting ASTM standards, the delivered price of switchgrass would have to be reduced by about [redacted]/ton to compensate Alliant from lost ash sales revenue and increased ash disposal costs. This price reduction would likely not allow the required income to make the project worthwhile to farmers. This highlights the importance of maintaining existing ash markets.

Exhibit ES-3 Breakeven Switchgrass Delivered Costs (F.O.B. to OGS Biomass Facility)

Regulatory/Financial Incentive Combination	Coal ($/ton)	Wind-Low ($/ton)	Wind-Ave ($/ton)	Wind-High ($/ton)
SO_2 alone (no GPI)	$10	$29	**$43**	**$58**
SO_2 + 25% GPI	$17	$29	**$43**	**$58**
SO_2 + 50% GPI	$24	$29	**$43**	**$58**
SO_2 + 100% GPI	$38	$38	**$43**	**$58**
SO_2 + PTC (no GPI)	$35	**$54**	**$68**	**$82**
SO_2 + PTC + 25% GPI	**$42**	**$54**	**$68**	**$82**
SO_2 + PTC + 50% GPI	**$49**	**$54**	**$68**	**$82**
SO_2 + PTC + 100% GPI	**$62**	**$62**	**$68**	**$82**

NOTES: Bold numbers in the table above represent scenarios where the switchgrass project could be commercially competitive. Costs in the table above assume no negative impact on existing ash markets. "SO_2" refers to SO_2 emissions credits valued at $150/ton. "PTC" refers to the section 45 production tax credit for wind and closed-loop biomass, valued at 1.8 ¢/kWh. "GPI" refers to green power incentives, and 25% GPI, 50% GPI, and 100% GPI refer to Alliant's Second Nature green power offerings that allow customers to buy electricity with a 25%, 50%, or 100% mix of renewable power, respectively. The overall premiums for the 25%, 50%, and 100% GPI scenarios are: 0.5 ¢/kWh, 1.0 ¢/kWh, and 2.0 ¢/kWh, respectively.

Exhibit ES-4 Summary of Toughest Competition Chariton Valley Biomass Project Would Outperform under Various Incentive and Delivery Price Scenarios

Regulatory/Financial Incentive Combination	Switchgrass Delivery Cost Scenario			
	Low ($40/ton)	Low-Medium ($52/ton)	Medium-High ($68/ton)	High ($92/ton)
SO_2 alone (no GPI)	Wind-A	Wind-H	none	none
SO_2 + 25% GPI	Wind-A	Wind-H	none	none
SO_2 + 50% GPI	Wind-A	Wind-H	none	none
SO_2 + 100% GPI	Wind-A	Wind-H	none	none
SO_2 + PTC (no GPI)	Wind-L	Wind-L	Wind-A	none
SO_2 + PTC + 25% GPI	Coal	Wind-L	Wind-A	none
SO_2 + PTC + 50% GPI	Coal	Wind-L	Wind-A	none
SO_2 + PTC + 100% GPI	Coal	Coal	Wind-A	none

* "Coal" means that this option is competitive with coal (1.5 ¢/kWh) production costs at OGS, wind-low (2.9 ¢/kWh), wind-ave (3.9 ¢/kWh), and wind-high (4.9 ¢/kWh); "Wind-L" means that this option is competitive with wind-low, wind-ave and wind-high; "Wind-A" means that this option is competitive with wind-ave and wind-high; "Wind-H" means that this option is competitive with wind-high only.

that must be achieved in order to make a given scenario commercially feasible (if possible). For example, if the project is able to capture SO_2 emissions credits, the production tax credit, but receives no green power incentives (this scenario corresponds to the row labeled "SO2 + PTC (no GPI)" in Exhibit ES-3) and is competing against an average Iowa wind project (this corresponds to the column labeled "Wind-Ave" in Exhibit ES-3), the breakeven delivered switchgrass cost for the project would be $68/ton.[7] If farmers can deliver their switchgrass to OGS for $68/ton or less, the project would be commercially viable. As shown in Exhibit ES-2, three of the example farm-side scenarios result in estimated delivered costs at or below $68/ton (the "Low", "Low-Medium", and "Medium-High" scenarios). The "Medium-High" scenario corresponds to 4 ton/acre/yr average yields, a high land charge ($100/acre), all acres get the CRP Pilot Program benefits, and high storage costs (steel sheds).

Breakeven switchgrass delivered cost numbers shown in bold in Exhibit ES-3 represent scenarios where the project could be commercially competitive. The breakeven delivered switchgrass costs for these scenarios are higher than the "Low" switchgrass delivered cost of $40/ton shown in Exhibit ES-2. This "Low" fuel delivery cost scenario is estimated to be the lowest feasible average delivery cost achievable by the farmers. In summary:

- The project would be competitive with coal production costs at OGS (this is the status quo condition, and the future situation where no increased renewables mandates are required in Iowa) if it gets market value for its SO_2 emissions credits, qualifies for the production tax credit, and gets about a 0.5 ¢/kWh green power premium or equivalent on all power generated from the project (corresponding to "25% GPI in the table).
- The project would be competitive with the average Iowa wind project under today's conditions, where the only incentives immediately available to the project are SO_2 emissions credits. This represents the situation where an increased renewables mandate is implemented in Iowa, as suggested in Iowa's *2002 Comprehensive Energy Plan Update.*
- The project would be competitive with the lowest-cost wind projects in Iowa if the project obtains SO_2 emissions credits and, like all wind projects, qualifies for the production tax credit.

Exhibit ES-4 present the same information as that presented in Exhibit ES-3, but in a slightly different form. At each the four switchgrass delivered price scenarios discussed in Exhibit ES-2, it shows what conditions are necessary for the project to outperform each of the competing systems considered. Each cell in the table lists the *toughest* competition that the Chariton Valley Project will outperform under the given scenario. To summarize results shown in Exhibit ES-4:

- *"Low" Delivery Cost Scenario:* If the farmers are able to deliver switchgrass to OGS at $40/ton, the project will be competitive with the average wind project in Iowa even if the project does not qualify for the production tax credit. With the production tax credit, it will outperform low-cost wind in all cases and production costs for coal at OGS with a 0.5 ¢/kWh or higher green power premium or equivalent.
- *"Low-Medium" Delivery Cost Scenario:* If the farmers are able to deliver switchgrass to OGS at $52/ton, the project will be competitive with high-cost wind projects in Iowa even if the project does not qualify for the production tax credit. With the production tax

[7] For this scenario to become applicable, the language for the production tax incentive would have to be expanded to allow cofiring closed-loop energy crops with coal, and an increased renewables mandate similar to that called for in Iowa's *2002 Comprehensive Energy Plan Update* would have to be implemented.

credit, it will outperform low-cost wind in all cases and production costs for coal at OGS with a 2.0 ¢/kWh or higher green power premium or equivalent.
- *"Medium-High" Delivery Cost Scenario:* If the farmers are able to deliver switchgrass to OGS at $68/ton, the project will not be competitive with any of the competition considered unless it qualifies for the production tax credit. With the production tax credit, it will outperform average-cost wind projects in all cases.
- *"High" Delivery Cost Scenario:* If the farmers are only able to deliver switchgrass to OGS at $92/ton, the project will not be competitive with any of the options considered, even if it qualifies for the production tax credit.

The results above show that there are multiple potential circumstances that will create the conditions to allow the project to achieve commercial project success. The two policies that could be most important to the project's competitive position are: 1) an increased renewables mandate in Iowa, and/or 2) the section 45 production tax credit. Iowa's *2002 Comprehensive Energy Plan Update* calls for reaching a goal of about 1000 MW (ten percent of generation) by 2010. Since Iowa presently has about 608 MW of installed renewable power capacity, about 392 MW of new renewable capacity would have to be installed to meet the 1,000 MW goal. The Chariton Valley Biomass Project would be very competitive in that situation. Expanded language for the section 45 wind and closed-loop biomass production tax credit would also have a large positive impact on the project's commercial viability. If *either* an expanded renewables mandate in Iowa *or* an expanded definition of the production tax credit occurs, the outlook for achieving commercial success will be very good. If *both* of these legislative changes occur, commercial success would be extremely likely.

Key Economic and Technical Criteria for Project Success

Based on the analysis described above and discussions between partners, the key economic and technical criteria required for project success are outlined below:

- Economic conditions must be such that all parties (growers, Prairie Lands, and Alliant) financially benefit from the project.
  - The conditions required for this to occur are discussed above and in more detail in Section 4. An economic tool was developed to allow partners to examine all cost-related issues associated with the project. This tool could be refined and used by partners during future contract negotiations.
- The project must not harm existing ash sales at OGS. Reduced ash revenues and increased disposal costs would make it extremely difficult for the project to produce favorable economics.
  - Tests conducted on ash samples from the first test cofire campaign for the project indicate that the *properties* of the cofired ash are sufficiently similar to those of non-cofired ash at OGS that the cofired ash could be successfully used for the same applications. More testing is needed to confirm these results. Work is presently underway to modify ASTM standards for using coal ash as a cement admixture to allow commingled biomass and coal ash to be acceptable as long as the *properties* of the ash meet the existing standards.
- Alliant has to feel comfortable that the cofiring project will not cause unacceptable conditions in the OGS boiler (unacceptable levels of slagging, fouling, corrosion, efficiency losses, emissions increases, etc.).
  - Based on results from the first cofire campaign and experiences at other similar operations, the project is not expected to create any such conditions. Long-term

testing is needed to confirm this prior to proceeding on a commercial basis at OGS. Since 1995 in Studstrup, Denmark, straw and coal have been cofired successfully at rates up to 20% straw input in a 350 MW pulverized-coal boiler. Techwise, the lead design firm for Studstrup's cofiring system, has been hired to lead design and testing efforts for the Chariton Valley Biomass Project to help ensure similar success.

If all of the above criteria can be met, there is a good probability that the Chariton Valley Biomass Project would continue on a commercial basis after the demonstration project is completed.

Next Steps/Other Issues

The analysis conducted for this report highlighted the importance of policy or market development efforts to the project's commercial viability. These include: emissions credits, green power markets, and state/federal incentives. With the exception of CO_2 trading, which is still in the infancy stage, most of these items can be viable both today and in the long term. The CVBP partners have been extremely active, with significant resulting progress to date, in both state and federal policy development activities that could create the conditions for commercial success for this project. Through their work with Senators Grassley and Harkin, they have taken a leadership role on both the CRP pilot project legislation and development as well as with the proposed modifications to the production tax credit language. On the state level, they have been active in developing Iowa's green power standard in a manner that includes cofiring as an approved technology (Iowa's is the first *Green-e* standard in the country that includes cofiring) and have also been closely involved in Iowa's state energy plan development process through their work on the Governor's Energy Task Force.

Chapter 5.0 begins with a review of Iowa's 2002 Energy Plan Update and then discusses each of these elements; all are summarized below. This section concludes with a brief overview of recent Iowa public opinion regarding alternative energy.

<u>Iowa 2002 Comprehensive Energy Plan Update</u>

Iowa's *2002 Comprehensive Energy Plan Update* highlights the importance of renewable energy and energy efficiency to the state's goals of energy independence and security, economic development, and environmental protection. It outlines many instances where renewable energy, including biopower, can play a pivotal role.

Overall, the Plan authors recognize the importance of legislative action to the renewable energy industry. They say that Iowa's natural resources and its agricultural expertise make it the ideal locale for the development of "homegrown" energy. However, despite its growth in renewable energy capacity, they say that state government incentives are needed for renewable energy to compete with fossil-fueled power. The Plan's policy recommendations relevant to biopower and this project include the following:

- *Establish a Statewide Public Benefits Fund*
  - The objective is to reduce electric and natural gas consumption in Iowa by 20% by 2010 and increase the amount of electric energy produced from renewable energy resources in Iowa to 10% of the total

  - The funding should be collected through a systems benefit charge and it will be used to establish a menu of rebates, loans, incentives, credits, grants, education, and R&D of energy efficiency and renewable energy technologies
- *Ensure State Government Leads By Example*
  - At least 10% of the electricity purchased by state government should be generated from renewable energy resources by 2005
- *Develop an Emissions Credit Trading Program*
  - The state should establish a credit-trading program for emissions avoided at state government facilities through energy efficiency and renewable energy initiatives

Since it is already underway, the CVRCD project is well positioned to benefit from these policies and contribute to the state's goals.

CO_2 Trading

Carbon trading is a relatively new concept but it is gaining attention as a policy tool. However, absent a global mandatory emissions reduction requirement, several companies, non-profit groups and governments have decided to undertake greenhouse gas (GHG) emissions trading. This market has emerged due to international treaty negotiations, anticipation of future regulations, and corporate foresight.

This project may benefit from two CO_2 trading efforts: one is through the Iowa state government and the other is with a regional trading exchange. Iowa's *2002 Energy Plan Update* recommends that the state establish a credit-trading program for emissions avoided at state government facilities. It applies to reducing criteria pollutant and carbon emissions through energy efficiency and renewable energy initiatives.

The second option offers a more near-term CO_2 trading opportunity for the CVBP. The Chicago Climate Exchange was established in 2001 as a regional GHG trading exchange. Participating companies would commit to voluntarily reducing their GHG emissions by 2% below 1999 levels during 2002 and 1% annually thereafter (Pew Center, 2002). The Exchange is expected to be up and running by the third quarter of 2002 for participants in seven states: Illinois, Indiana, Iowa, Michigan, Minnesota, Ohio, and Wisconsin. Based on data from average CO_{2e} trades, the CVBP could see a benefit between 0.06 ¢/kWh and 0.36 ¢/kWh if it engages in CO_2 trading. Based on this range of CO_2 values, participating in this program could provide an additional $165,000 to $991,000 of revenue for the project per year.

Green Power Markets

Green power markets are a way for power providers and their customers to jointly stimulate the renewable energy industry. The state of Iowa has mandated that all utilities in the state have to offer green power options to their customers beginning January 2004. Alliant Energy has already begun offering a green power option to its residential customers. Its Second Nature program levies an additional 0.5, 1.0, or 2.0 ¢/kWh premium, based on three participation levels of 25%, 50%, or 100% renewable power, respectively. If all of the project's power could be sold at a 2.0 ¢/kWh premium, the increased revenue to the project from green power sales would be about $5.5 million per year. At a 1.0 ¢/kWh premium, revenue would increase by $2.75 million per year, and the increased revenue would be about $1.375 million per year if all of the project's power was sold at a green premium of 0.5 ¢/kWh.

However, the residential sector alone may not be a large enough green power market to significantly impact the Chariton Valley Biomass Project. At a minimum, Alliant would need to sign up more than 35,000 average residential customers at the highest participation level (100% renewable power) to consume all of the power generated by the project in a year. This means that nearly 8% of Alliant's total residential customer base would have to purchase green power from this project, and that number neglects the green power generated from other renewables in Iowa. By comparison, the customer participation rates for the top ten utility green pricing programs range from 3% to 7%, with a premium ranging from 1.0 to 1.5 ¢/kWh (DOE, 2002).

Thus, project partners would most likely have to expand their green power marketing efforts to include the corporate and government sectors. Compared to the residential sector, these two consumer groups have an institutional interest in purchasing green power, have greater financial means to do so, are more aware of alternative technologies, and they can buy it in larger volume. Corporations' incentives to buy green power are to save money and/or to adhere to corporate social responsibility (CSR). CSR is a growing management trend where companies voluntarily align their normal business practices to address environmental and social issues; renewable energy and energy efficiency have become popular ways for businesses to incorporate CSR.

Government agencies can fulfill executive directives and set an example. In fact, Iowa's *2002 Energy Plan Update* acknowledges this role—it says that at least 10% of the electricity purchased by state government should come from renewable energy sources by 2005. To provide some perspective, in 2001, it is estimated that Iowa state government facilities consumed 561,320,413 kWh of electricity, so 10% would be 56,132,041 kWh/yr. (Iowa Dept. of Natural Resources, 2002). If the CVBP is expected to generate 275,360,000 kWh/yr, then at the 10% purchase rate Iowa state government can purchase approximately 20% of the project's output. This alone is nearly enough to reach the "25% GPI" level shown in Exhibits ES-3 and ES-4.

Federal agencies can also make a large contribution. Energy Secretary Abraham recently challenged DOE operations to buy renewable energy to supply 5% of the agency's total annual energy needs by the year 2005. In April 2002, DOE announced that it would purchase green power to supply 17% of the electricity needs at its headquarters facilities in Washington, DC and Germantown, MD. (NREL, 2002)

In addition, Executive Order 13123 directs the Federal government to reduce energy consumption per square foot in federal buildings by 30% in 2005 and 35% in 2010, relative to the 1985 baseline. Renewables purchases count as energy consumption reductions, on a one-to-one basis, toward meeting this goal. EO 13123 also requires federal facilities to derive 2.5% of their annual electricity consumption from renewables. This is equivalent to 1,422 GWh/yr. So far, the Federal government has met approximately 28% of the 2.5% renewables goal established in EO13123, with most of it coming from green power purchases (usually at premiums of at least 2 ¢/kWh) and biomass power.[8] The remaining 1,023 GWh/yr of targeted renewables purchases are about 3.7 times the total amount of power generated by the Chariton Valley Biomass Project. While it is not likely that the project could sell all of its power to one buyer, it may be possible to sell a significant fraction of the project's power to the Federal or state governments or other large consumers. By considering all potential green power buyers, including residential, governmental, and commercial customers, project partners may be able to sell enough of the project's power into the green power market to make a significant difference toward making the project commercially viable.

[8] Federal Energy Management Program, 2002.

State/Federal Incentives

Three major government initiatives have been shown to be very important to the commercial success of this project: possible increased renewables mandates in Iowa, the Federal Production Tax Credit (PTC), and the Federal Conservation Reserve Program (CRP).

Under Iowa's Alternative Energy Law, the state's three investor-owned utilities were required to purchase a total of 105 MW of renewable power; these utilities have already met this requirement. The Governor's Energy Task Force recommended reaching a total of 1,000 MW of renewables capacity by 2010; this is comparable to the Energy Plan's recommended 10% renewables goal by 2010. To pay for this increased capacity, the Plan suggests establishing a systems benefit charge (SBC) that will be levied on all electric, natural gas, fuel oil, and propane-consuming customers in the state. By 2001, Iowa had 608 MW of installed renewable power capacity, most of it wind power installed since 1998. This leaves 392 MW to be installed to meet the 1,000 MW goal.

The analysis provided in Appendix G estimates that the average Iowa electric bill "mark-up" needed to fully pay for this project, with no other incentives except the existing SO_2 credits, would be only 0.0211 ¢/kWh (at an average delivered switchgrass cost of $52/ton). This equates to an average additional cost of $6.59/yr (or $0.55/month) for each residential electric customer in the state. The analysis in Appendix G compares this amount to rate riders used in Iowa to pay for existing energy efficiency programs and alternate energy production. This comparison indicates that the amount required for the CVBP is only 6.4% of the existing Energy Efficiency Cost Recovery Rider or 16.1% of the existing Alternate Energy Production Clause Rider. Therefore, absent any presently unavailable incentives, a relatively small systems benefit charge would make the project commercially viable.

The section 45 production tax credit (PTC) was shown to be a potentially key component of the project's economics, but as currently written the parameters are too restrictive for most biomass projects. In fact, very few biomass projects have qualified for this incentive over its 10-year existence. Conversely, wind power developers have received an estimated $1.14 billion in obligated funds from this credit (this estimate very conservatively neglects any qualifying wind projects after the year 2001). If this 1.8 ¢/kWh credit becomes available to this project, it could be worth about $4.96 million per year. Over the course of the 10-year life of the credit for the CVBP, the cumulative value of this credit to the CVBP would be less than 4% of that already obligated to wind projects (neglecting all costs from post-2001 wind installations).

The CRP program turns out to be beneficial to both the farmers and the federal government. The farmers receive a rental payment for planting switchgrass on CRP land, which helps them reduce their delivered cost of fuel and increases their competitiveness. To illustrate this point, assuming an average $92.49/acre rental rate, if all switchgrass is planted on CRP land, the Program would benefit the CVBP at the following levels:

- $4.16 million/year, or about $20.81/ton of switchgrass at an average annual yield of 4 tons/acre; or
- $2.77 million/year, or about $13.87/ton of switchgrass at an average annual yield of 6 tons/acre

In addition, the government ends up saving money because it would pay 10% less per acre to these farmers compared to the amount paid to farmers to keep CRP land fallow. If 50,000 acres are harvested for switchgrass production, the federal government would save $465,000 a year through this project.

Public Opinion of Alternative Energy

The 2002 Energy Plan, current green power programs, and government efforts all point to increasing acceptance of renewable energy in Iowa. Complementary to this is the public's positive view of alternative energy and its importance. Results from two recent polls conducted in Iowa are summarized below (Iowa Dept. of Natural Resources, 2002; The Mellman Group, 2002):

- A survey of Iowa farmers found that:
  - 87% believe Iowa should invest more in alternative energy sources
  - 94% believe more research should focus on new alternative energy uses for Iowa farm commodities
  - 90% believe more research should focus in new alternative crops for Iowa
- A survey of likely Iowa voters found that:
  - 67% believe that promoting renewables and energy efficiency are the best way to solve the nation's energy crisis
  - 70% favor requiring power companies to generate 20% of their power from renewable sources

Potential Benefits of the CVBP

This analysis has shown multiple pathways for the Chariton Valley Biomass Project to achieve commercial success in this first-of-a-kind closed-loop biomass energy crop project. For commercially viable conditions to exist, one or more new policy or market developments will have to occur. These developments could include one or more of the following: an increased renewables mandate in Iowa, expansion of the section 45 wind and closed-loop biomass production tax credit (to allow generators cofiring closed-loop energy crops to qualify for the credit), or the development of a significant green power market among Iowa residential, governmental, and commercial electricity consumers.

Because this project would be located at an existing Iowa power plant, it could provide new renewable power generation capacity in Iowa without encountering electricity transmission system constraints that often hinder new wind projects. It would also provide a new source of *base-load* renewable electricity generation in Iowa—base-load generation options are advantageous to power generators, planners, and marketers because they provide predictable power output and are not directly subject to intermittent conditions such as wind speeds (as in the case of wind power projects) or sunlight (as in the case of solar power projects).

If the project succeeds commercially, it will result in air emissions reductions (particularly SO_2 and *net* CO_2 emissions), and water and soil quality benefits in Southern Iowa and the Lake Rathbun watershed. In addition, it would replace the purchase of about 176,000 tons and $2.7 million per year of out-of-state coal with the purchase of about 200,000 tons per year of switchgrass grown locally by Southern Iowa farmers. An estimate of the potential value of the CVBP to individual Iowa farmers was conducted as part of this analysis. The results show that for two potential commercially viable and feasibly attainable scenarios, an average farmer could earn about 30% to 35% of their average annual net farm income from the farming of only 20% to 30% of their lands to supply biomass fuel to Alliant. Since the farmer's return on their land used for the CVBP would be higher than average returns obtained through other land uses, it appear that participation in the project would be attractive to farmers. In total, for all 500 potential farmers, the net farmer income associated with the project would be between $6.3 and $7.65 million per year under these scenarios.

1.0 INTRODUCTION

1.1 Overview of Chariton Valley Biomass Project

The primary goal of the Chariton Valley (CV) Biomass Project is to develop markets for energy crops in southern Iowa. A feasibility study identified herbaceous switchgrass as an attractive biofuel for cofiring with coal at the Ottumwa Generating Station (OGS), thus presenting an opportunity for developing and sustaining a market for energy crops in southern Iowa. The development of gasification technologies was subsequently added to the cofiring approach.

The CV Biomass Project is coordinated by the Chariton Valley Resource Conservation and Development (CVRCD) organization. CVRCD is a non-profit corporation that receives technical assistance from the USDA's Resource Conservation and Development Program. The stated purpose of the RC&D Program "…is to accelerate the conservation, development, and utilization of natural resources, to improve the general level of economic activity, and to enhance the environment and standard of living in authorized RC&D areas."

1.2 Objective of Fuel Supply Contracts Report

This report includes a draft biomass fuel supply contract between Prairie Lands and Alliant Energy for cofiring switchgrass at OGS. It is based on a combination of a traditional fuel supply contract and the fuel supply contract used for a straw-fired energy facility in Denmark. A brief description of alternative contract vehicles is included for comparison. The draft contract addresses: biomass quality, delivery terms and schedules, pricing and payment terms, rejection criteria, storage requirements, and warranties and liabilities.

The report also includes a discussion of a financial analysis model that was developed to consider the project's performance under a range of scenarios; results are discussed in the text and graphically displayed. The model was used to identify and quantify the impacts and risks associated with key factors that could influence the commercial viability of the project: ash marketability, tax and CRP program incentives, biomass production costs, capital costs for biomass storage/processing facilities, tradable emissions credits, green power premiums, and financing terms.

The analysis compares the cost of generating power from switchgrass cofiring to the cost of producing wind power in Iowa (for examining competition under a state renewables mandate) or coal-only power at OGS (for examining competition in the absence of a state renewables mandate). The model is used to identify conditions under which the project can be commercially viable relative to existing or expected competition, thus revealing the conditions necessary for the sales contract to be implemented.

1.3 Project Status

Project partners have held a series of meetings to identify the full set of issues that need to be addressed in any commercial agreement for the project. A draft supply agreement, based on a combination of a traditional utility fuel supply contract and the fuel supply contract used for a straw-fired energy facility in Denmark, has also been completed. A model has been developed to consider economic performance of the project under a range of scenarios and to identify conditions under which the project can be commercially viable.

1.4 Project Partners

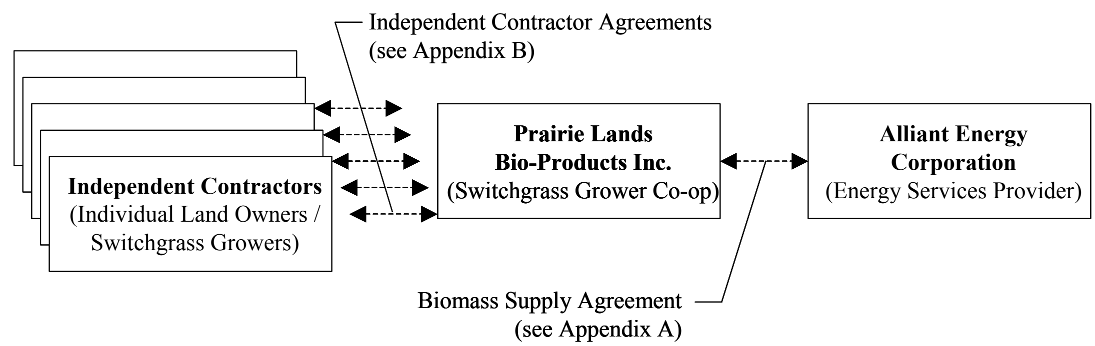
The CV Biomass Project participants have included: Alliant Energy; Chariton Valley RC&D, Inc.; Energy Research Corporation; Iowa Department of Agriculture and Land Stewardship; Iowa Department of Natural Resources; Soil and Water Conservation Districts; Iowa Farm Bureau Federation; Iowa Energy Center; Iowa State University (ISU); University of Iowa; John Deere Works; Kelderman Manufacturing; ISG Resources; Leopold Center for Sustainable Agriculture; National Renewable Energy Laboratory (NREL); Oak Ridge National Laboratory; Prairie Lands Bio-Products, Inc.; U.S. Department of Agriculture; U.S. Department of Energy; Vermeer Manufacturing Company; Hazen Research; Mostardi-Platt; Techwise, TR Miles Consulting; Bradford Conrad Crow Engineering, and Antares Group Inc.

2.0 BIOMASS SUPPLY AGREEMENT

2.1 Parties Involved in Contract Agreements

Exhibit 2-1 shows two planned contractual agreements and the parties involved in a commercially operating Chariton Valley Biomass Project. The three contractual parties are: Alliant Energy Corporation, Prairie Lands Bio-Products Inc., and as many as 500 independent contractors (switchgrass growers). Alliant Energy Corporation is an energy-service provider that serves more than 1.3 million customers in Iowa, Illinois, Minnesota and Wisconsin. Prairie Lands Bio-Products, Inc. is a not-for-profit organization with a current membership of close to 60 switchgrass growers. Prairie Lands' membership elected a board of directors to oversee the organization's activities. Its mission is to: identify and develop switchgrass products and markets for those products, produce switchgrass to satisfy demand for products, evaluate environmental benefits of producing and using switchgrass, and inform and educate the public about the potential of switchgrass. The independent contractors are as many as 500 Southern Iowa farmers who would raise switchgrass on their own lands or land rented from others, and deliver it either directly to the switchgrass storage and processing facility at OGS or to intermediate storage facilities in the Chariton Valley Biomass Project area.

Exhibit 2-1: Contracting Agreements and Parties for Chariton Valley Biomass Project



NOTE: The draft biomass supply agreement has been developed based on Alliant Energy fuel supply contracts and the fuel supply contract from the operating straw/coal cofiring plant at Studstrup, Denmark (see Appendix C).

To streamline communications for this project, Alliant wants to deal with a single organization (Prairie Lands) rather than with multiple independent contractors as other utilities have done in similar projects. A single "*Biomass Supply Agreement*" between Alliant and Prairie Lands will cover terms and conditions required for delivering processed switchgrass to the burner tips of several burners in the OGS boiler. A draft of this agreement is provided in Appendix A and briefly is summarized in section 2.4 of this report. This draft contract specifies requirements for: biomass quality, delivery terms and schedules, pricing and payment terms, rejection criteria, and warranties and liabilities. It was developed based on existing Alliant Energy fuel supply contracts and the fuel supply contract from the operating straw/coal cofired power plant at Studstrup, Denmark (see Appendix C).

Prairie Lands will coordinate all activities involved in raising, harvesting, storing, delivering, and processing switchgrass and supplying it to the OGS burners. Production, storage and delivery of switchgrass from independent switchgrass growers to Prairie Lands will be handled through

"*Independent Contractor Agreements*" between Prairie Lands and each grower/contractor. Appendix B includes a draft of this agreement and key provisions are briefly summarized in section 2.5 of this report.

It should be noted that in addition to the Studstrup, Denmark project serving as an example for contract agreements and required operations, Alliant can draw experience from a similar project of its own. For years, Alliant has been cofiring resifil (processed oat hulls) with coal at its Sixth Street Station power plant in Cedar Rapids, Iowa. From Alliant's operational perspective, the resifil project would be very similar to the OGS cofiring project. Resifil is produced as a waste byproduct from a Quaker Oats manufacturing facility located adjacent to the Sixth Street Station property. It is prepared for combustion at the Quaker Oats facility and blown through a pipe to the boilers at Sixth Street Station. About 7.5 MW of power is generated from the heat input provided by the resifil. Boiler operators at Sixth Street Station communicate by phone with staff at the Quaker Oats facility to coordinate burn times (on versus off) for the resifil delivery system. Alliant is responsible for all equipment, maintenance, and labor on its end of the delivery pipe, and Quaker Oats is responsible for those items on its end.

2.2 Types of Contracts

Two commonly used contract vehicles for procuring fuel for power plants are: 1) "traditional" fuel supply contracts, and 2) tolling agreements. The most common contract form is the "traditional" fuel supply contract where the power generator purchases its fuel supply from an external party. The power generator maintains responsibility and control over all other actions and transactions required to convert that fuel into electricity and to sell the electricity to end-users. Terms of these agreements deal primarily with fuel supply volumes, quality requirements, price, delivery period, future price escalation, and other more general terms and conditions. If all quality and delivery requirements have been met, the fuel supplier's role ends with delivery of the fuel. At this time, both Alliant and Prairie Lands would prefer to use a traditional fuel supply contract. This type of agreement will be the simplest and will provide each organization control and responsibility in their core area of expertise: Alliant will have control and responsibility for all aspects associated with generating and selling electricity, and collecting associated tax and emissions credits (if applicable); and Prairie Lands will have control and responsibility for all aspects of supplying and processing biomass. Alliant would essentially buy processed biomass delivered to the burner tips of several burners in the OGS boiler.

While it is not of primary interest at this time, a tolling agreement may be worth future consideration. This agreement would allow Prairie Lands to "rent" part of the boiler and generator to convert the energy from its switchgrass to electrical energy. Prairie Lands could then take possession of the electricity for sale and/or some part of the environmental attributes (emissions credits, green power, etc.) for sales, trades, or banking. While a commercially operating Chariton Valley Biomass Project would be a small part of Alliant's business, it would represent a primary income for Prairie Lands. Capitalizing on external benefits such as greenhouse gas credits or marketing the resulting green power would create value-added revenue streams improving chances for commercial success of the project, and it *may* therefore be of greater organizational priority for Prairie Lands as compared to Alliant. Alliant and its partner MidAmerican Energy may benefit from a "guaranteed" revenue stream for energy conversion services and management of fuel supply and electrical sales risk. Although these benefits could be reflected in a traditional fuel supply contract, a tolling agreement could allow an increased role for Prairie Lands in the marketing of the electricity and environmental attributes and could result in an improved financial and risk allocation situation for all parties. The general mechanics of a tolling agreement are briefly discussed below for informational purposes only—all presently planned future contract development efforts will be aimed at developing a refined traditional fuel supply contract.

The tolling agreement has emerged in part as a way for power generators to manage market risk in deregulated markets, moving the risk of fluctuating fuel and/or electricity prices to the fuel supplier. Tolling agreements are contracts where a fuel supplier rents the energy conversion services of a generating plant. Specifically, Party A owns the power generating plant and enters into an agreement with Party B to convert fuel into electricity. Party B owns the fuel and may own or simply market for a fee, the electricity (and/or emissions credits) that will be produced. Under a tolling contract, Party B pays Party A a fixed amount for a fixed period of time for the conversion services.

In summary, the main differences between a tolling agreement and a traditional fuel supply contract are: 1) the compensation for a generating plant's conversion services, 2) the distribution of fuel price and power marketing risk, and 3) the final ownership of the electricity and/or emissions credits. In a traditional fuel supply agreement, the supplier's responsibility and involvement end at the power plant's gate. In a tolling agreement, the fuel supplier maintains title to the fuel and buys conversion services from the power plant owner. The fuel supplier may have contractual possession of the electricity generated or may market the resulting electricity and pay a lines charge for transmission and distribution services.

2.3 Essential Conditions for the Cofiring of Biomass at Ottumwa Generating Station

Prior to the development of the Draft Fuel Supply Agreement, project partners held a series of meetings to identify the full range of issues that should be addressed in a final contractual agreement between Alliant and Prairie Lands for commercial operation of the project. Each of these conditions is listed below, with a brief description of either the treatment of each issue within the draft contract, or the current thinking of project partners regarding the issue. Each issue/condition is shown below in *italics*, and explanation details are shown in normal text. The present version of the draft contract does not explicitly deal with all of the issues listed below, but a final contract will. The terms in the draft contract and items listed below are open for future negotiation.

1. *Describe cofiring operational issues in both regulated and deregulated environments.* This item is not presently addressed in the draft agreement. Actions to deregulate electricity in Iowa have been suspended.

2. *Agreement must be structured to allow full use of tax credits and other policy initiatives such as renewable portfolio requirements.* – The draft agreement is presently structured for Alliant to own the electricity generated from the project and to manage collection of tax credits, RPS, and green power benefits if applicable.

3. *Identify and consider all cost elements:* (All of the following items have been incorporated into the economic analysis tool developed by Antares and described in more detail in sections 3 and 4. The model will allow partners to consider different project scenarios—e.g., with and without production tax credits and green power premiums, with and without portfolio standards, etc.—and quickly determine the required payment ($/ton) to contract switchgrass growers to make the project commercially viable. The contract value for payment from Alliant to Prairie Lands for the biomass fuel supply under different scenarios can also be quickly estimated by the model. This tool will be helpful during future contract negotiations for determining the contract price Alliant

would pay Prairie Lands for switchgrass. A summary of the conditions under which the project could financially break even during commercial operation is provided in chapter 4.)

a. *Delivered cost of biomass (e.g., fuel qualitative valuation)* – The delivered cost of biomass will depend on the combination of market and policy incentives and a full accounting of factors "b" through "i" below.
b. *Facility operation and maintenance* – This cost is not explicitly addressed in the draft contract agreement, but O&M costs for both the biomass processing facility and the biomass project's share of non-fuel O&M at OGS are incorporated into the economic analysis tool. Present plans are for Prairie Lands to be responsible for all O&M costs and activities at the biomass facility, and for Alliant to be responsible for all O&M costs and activities at OGS.
c. *Labor* – Similar to O&M, this cost is not explicitly addressed in the draft contract, but present plans are for Prairie Lands to be responsible for all labor at the biomass processing facility and for Alliant to be responsible for all operations at OGS. Estimates of these costs are built into the economic analysis tool.
d. *Debt service on capital* – Present proposed plans are to have zero debt service requirements on capital expenses because project capital costs will be provided by government cost-share. The economic analysis tool is designed to consider debt service on capital in case capital costs are not fully covered by cost-share.
e. *Efficiency loss* – A slight efficiency loss is expected when cofiring biomass. Based on efficiency impact measurements reported from other cofiring projects, the economic analysis tool accounts for these losses and discounts the required delivered price of switchgrass to offset this loss (i.e., because of the efficiency penalty, Alliant would be willing to pay less per ton of switchgrass than it would otherwise). Measurements during future test campaigns will be used to refine the accounting of this loss.
f. *Fouling factor* – The economic analysis tool also accounts for effects of slightly increased fouling and discounts the required delivered price of switchgrass accordingly (i.e., because of the additional fouling during cofiring, Alliant would be willing to pay less per ton of switchgrass than it would otherwise).
g. *Fly ash sales and/or disposal* – The economic analysis tool allows consideration of reduced ash marketability due to cofiring operations at OGS. Lost ash sales are valued at [redacted] per ton of ash. For instances where ash sales are assumed to be negatively impacted, the tool also accounts for disposal costs associated with the unmarketable ash at a rate of [redacted] per ton of ash. Ash sale value and disposal cost rates were obtained from Alliant staff. As discussed in further detail in section 4, it is very important for the project to ensure that ash markets for OGS are not negatively impacted. Test results conducted on commingled coal/biomass ash from the campaign 1 test burn indicate that the properties of the ash should not preclude it from being sold into existing markets (i.e., to existing customers).
h. *Administration* – Administrative costs, including insurance, have been estimated and are included in the economic analysis tool.
i. *Risk and Incentive factor* – A placeholder of $150,000 per year has been placed in the economic analysis tool as an incentive and compensation for increased risk assumed by Alliant when cofiring switchgrass.

NOTE: All of the estimates for costs listed above will need to be further refined to ensure the most thorough and accurate analysis possible.

4. *Consider any environmental impacts:*

   a. *Permit requirements (e.g., emissions differences, facility operations)* – Required fuel specifications and measured emissions results from cofire test campaigns will be such that emissions at OGS are not negatively impacted, or that if small increases are experienced, the increases are not large enough to trigger a PSD review.
   b. *Credits (quantity, value, and ownership)* – Emissions credits for SO_2 reductions are estimated by the economic analysis tool and are valued at $150 per ton of SO_2 based on recent market value. By default the model assumes no net change in NO_x emissions and zero value associated with CO_2 credits. It is currently assumed that Alliant would own all emissions credits generated through the project.

5. *Describe alternatives regarding:*

   a. *Ownership of cofiring facilities and equipment (e.g., lease, removal)* – Current plans are for Prairie Lands to own the biomass facilities and equipment.
   b. *Operation and use of cofiring facilities and equipment* – Prairie Lands will manage and operate the biomass facilities at OGS.
   c. *Obligation to deliver fuel* – Prairie Lands will be required to deliver approved biomass to OGS according to an annual schedule attached to the agreement. A force majeure clause exempts delivery requirements in the event of acts beyond the reasonable control of, and not caused by the fault or negligence of Prairie Lands. The annual target for the project is 200,000 tons of switchgrass per year.
   d. *Ownership of delivered fuel* – The draft contract presently specifies that ownership of the biomass transfers to Alliant F.O.B. at the biomass processing facility. To be consistent with Alliant's present desire to purchase biomass at the burner tips of the biomass burners in the OGS boiler, ownership transfer may be amended in future versions of the contract agreement to occur at Alliant's burner tips.
   e. *Obligation to generate* – Alliant is obligated to purchase biomass according to the contract schedule unless: 1) force majeure conditions are encountered, 2) labor strikes or lockouts occur at OGS, 3) in Alliant's sole discretion the biomass cannot be burned for operational, environmental, and/or regulatory reasons without modifications to OGS.
   f. *Ownership of the power generated* – Present plans are for Alliant to maintain ownership of the power generated from biomass.
   g. *Sale and delivery of the power generated* – Present plans are for Alliant to sell and deliver the power generated from biomass.
   h. *Ash sale and disposal* – Present plans are for Alliant to manage the sale and disposal of all ash from OGS.
   i. *Timeframe* – The time period for the contract has not been determined yet.

6. *Identify and assign liabilities with respect to all contractual items* – See draft agreement in Appendix A for further details.

2.4 Overview of Draft Fuel Supply Agreement

This section briefly summarizes the key elements of the draft biomass fuel supply contract between Prairie Lands and Alliant Energy. Appendix A contains a draft of the entire biomass fuel supply contract. It is based on a combination of a traditional utility fuel supply contract from

Alliant Energy and the fuel supply contract used for the straw/coal cofired power plant in Studstrup, Denmark.

2.4.1 Quality Assurance of Biomass

- Quality of biomass—lists requirements for purity of biomass (e.g., no magnetic material or foreign impurities) and penalties for violating the fuel rejection limits

2.4.2 Delivery Terms and Schedules

- Transport of biomass—describes the documentation needed when the biomass is unloaded at the storage facility; delivery receipt has to include weight, and moisture content of the biomass
- Size of biomass bales—lists the specifications for width, length, depth, and weight for each bale
- Moisture content of biomass bales—lists average moisture content percentages and how they are to be measured
- Loading of biomass bales—provides specifics on how the bales are to be placed on the truck
- Rejection criteria—lists reasons why Alliant can reject the biomass bales, including deviation from size requirement, excessive moisture content, and improper loading
- Vehicles—describes loading dimensions and unloading procedures for trucks
- Tonnage guarantee—lists the number of bales needed to be available for processing and procedures during scheduled plant shut-downs
- Opening hours—provides the days/times that the power plant will be open for receipt of biomass
- Force majeure—states that the parties are not liable in the case of force majeure (circumstances beyond the control of the parties such as Acts of God, fire in biomass storages, etc.)

2.4.3 Pricing and Payment Terms

- Pricing—lists the dollar per ton basis price for biomass based on the heat content; it also includes price adjustments based on seasonal variation, weight correction, and Btu variation
- Terms of payment—specifies monthly invoice and payment dates

2.4.4 Warranties and Liabilities

- Lists responsibilities for equipment damage, specifications for express and implied warranties, and non-disclosure clauses

2.5 Overview of Draft Independent Contractor Agreement

Appendix B contains a draft of the independent contractor agreement between Prairie Lands and individual switchgrass growers. The scope of work attached to the agreement specifies the contractor's requirement to: 1) follow recommendations provided by Prairie Lands and the Chariton Valley RC&D, 2) participate in field harvest plan development and review with Prairie Lands and the Chariton Valley RC&D, 3) assist with the collection of harvest and yield related data and samples, 4) perform all activities related to harvest and delivery of a maximum quantity of switchgrass to a specified storage facility, and 5) provide switchgrass that meets the following specifications (the values shown below are based on current thinking and are subject to change):

a) 100% large square bales (3 ft x 4 ft x 8 ft) with plastic twine
b) maximum moisture content of 15% by weight
c) maximum inorganic/trash content of 1% by weight
d) negligible rotten material and wet spots

Separate payment rates are specified depending on whether the switchgrass is delivered directly to OGS or to an intermediate, off-site storage facility.

3.0 ECONOMIC ANALYSIS TOOL – ASSUMPTIONS & DEFINITIONS

A project economic analysis was conducted to determine which scenario and combination of project incentives would provide the greatest chance for project success. This chapter discusses the assumptions and definitions used in the analysis; results are provided in chapter 4.0. It begins by defining the Federal regulatory incentives available to Alliant Energy and Prairie Lands Bio-Products. It then discusses the components of switchgrass production and delivered costs and derives estimated values for each of them. The next section calculates the cost of electricity (COE) for the switchgrass portion of the project and then discusses the average COE for coal power at OGS and wind power in Iowa. The next chapter compares the various COE values under different project scenarios.

3.1 Value of Potential Regulatory Incentives

This section will discuss the three potential incentives for the project: sulfur dioxide (SO_2) credits, the Renewable Energy Production Tax Credit (PTC), and the Conservation Reserve Program (CRP). All three credits are currently available. Power producers can use the SO_2 credits and the PTC and the farmer can use the CRP payments, but their applicability hinges on the cooperation of both parties. The SO_2 credits and the CRP program are currently being used, but the PTC is not; it still requires some legislative changes to become more useful.

3.1.1 SO_2 Credits

Some SO_2 reductions will result from this project. Cofiring 200,000 tons of switchgrass a year decreases coal consumption, which is expected to reduce SO_2 emissions by 1,374 tons/yr, or 6.1%.[9] Emissions measurements during cofire tests will be used to refine this estimate prior to commercial operation. Based on emissions measurements from the first cofire test campaign, SO_2 reductions could be slightly larger—it is suspected that the potassium in the switchgrass may help remove additional SO_2. The current market value of SO_2 credits is approximately $150/ton, so the financial incentive to OGS for selling or trading SO_2 credits is calculated at $206,100/yr. At an overall effect of 0.7 mils/kWh, this incentive provides the least amount of financial benefit among the three incentives discussed in this section;[10] however, it is one of two incentives that would be fully available to the project under existing conditions (i.e., without changes to existing policy in the case of the PTC). The CRP biomass pilot program benefits would also be fully available today.

3.1.2 Production Tax Credit

The Section 45 Production Tax Credit (PTC) for wind, closed-loop biomass and poultry litter has been extended for two years and qualifying facilities now have to be in place by January 2004. Once a project has qualified, the credit is available for ten years and is a dollar for dollar reduction in the power company's tax obligation. Biomass cofiring is not presently eligible for this credit, however, Congress has considered including it as an eligible technology during several previous legislative sessions. Aside from several extensions of the credit qualification date, the credit was *expanded* once to allow the use of poultry litter as a fuel. The economic

[9] Currently, OGS produces 22,508 tons of SO_2 emissions a year. Cofiring 200,000 tons of switchgrass per year is expected to lower these emissions by about 6.1% (equal to the cofiring percentage on an annual heat input basis, with a slight adjustment for boiler efficiency losses due to cofiring). Thus, the SO_2 emissions reduction is estimated at 1,374 tons/yr (22,508 x 6.1%).

[10] This number assumes an annual biopower production of 275,360,000 kWh/yr.

analysis described in chapter 4 therefore assumes that if the Section 45 credit language is modified to allow cofiring closed-loop energy crops, the pre-tax levelized value of the PTC would be 1.8 ¢/kWh (2002 $US) for all power produced from the Chariton Valley Biomass Project.[11] If obtained, this tax credit would be worth about $4.96 million per year for the project (pre-tax).

3.1.3 Conservation Reserve Program (CRP) Biomass Pilot Project

The CRP is a voluntary federal program that offers annual rental payments, incentive payments for certain activities, and cost-share assistance to establish approved cover on eligible cropland. The program encourages farmers to plant long-term resource-conserving covers to improve soil, water, and wildlife resources, and in return, the farmers receive a "rental payment."

In the year 2000, the federal government authorized the CRP to conduct pilot projects where biomass would be harvested on CRP land and used for energy production; the farmer would continue to receive a (reduced) rental payment. The terms for each qualified pilot project specify harvesting frequency and acreage, and stipulate that the biomass cannot be used for any commercial purposes other than energy production. The Chariton Valley Biomass Project is one of six pilot projects that have qualified for this program. Under this pilot effort, the farmers still have an incentive to keep the land in the CRP program, but they also have the opportunity to use it to produce a revenue-generating crop. (USDA/Farm Service Agency, November 2000) Prior to this pilot project, harvesting on CRP acres was not allowed. The terms of the pilot project include the following:

- No more than 25% of total acreage in any National Agricultural Statistics Service (NASS) Crop Reporting District may be harvested in any single year.
- The total area of all six projects must not exceed 250,000 acres and individual projects must not exceed 50,000 acres.[12]
- The payment reduction equal to 10% of the annual rental payment will apply during the year the acreage is harvested.[13]
- Pilot projects must be conducted for a minimum of 10 years.

This biomass pilot project encompasses a 70-mile radius around OGS. That area contains all or parts of four NASS Crop Reporting Districts; a list of the counties within the project area is provided in Exhibit 3-1. According to USDA reports, these counties had a total of 835,645 acres of CRP lands. CRP acres and average land rental rates are shown in Exhibit 3-2 for each county and crop-reporting district in the project area. The district with the least amount of CRP lands is Central Iowa (containing the greater Des Moines area), with a reported 129,493 acres of CRP lands. Based on these numbers, if the average annual yield for the lands is 6 tons/acre, the project would not be limited by the CRP pilot project's 25% rule even if nearly all of the planted acres for the project were CRP lands from the Central Iowa district. Based on an average annual 4

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[11] The value of the tax credit is adjusted annually for inflation with a base value of 1.5 ¢/kWh in 1992—the tax credit is 1.8 ¢/kWh in 2002 $US. Considering a tax rate of 35%, the tax credit would be worth about 2.8 ¢/kWh (in 2002 $US) to Alliant on a pre-tax basis *during each of the ten years in which the PTC was applied*. Levelizing the pre-tax value of this 10 year credit over a 20 year project life yields a pre-tax value of 1.8 ¢/kWh for the PTC (based on a discount rate of 6.4%).

[12] Other biomass pilot projects intending to use this program are in New York, Oklahoma, Illinois, Minnesota, and Pennsylvania.

[13] This project will receive 90% of the annual rental payment as opposed to 75% stated on the USDA Biomass Pilot Program guidelines.

ton/acre yield, this project will not require more than 50,000 acres and would therefore not be constrained by the 25% rule even if all acres for the project are planted in any one of the three other NASS districts. To produce 200,000 tons/year at a 4 ton/acre average yield, it will require approximately 6% (50,000 ÷ 835,645) of the currently active CRP contract lands within the 70-mile radius around OGS. The weighted average annual rental rate for the project area is $92.49/acre, with an average of $100/acre in the South East Iowa district that lies wholly within the project area. Based on an average $92.49/acre rental rate, if all switchgrass is planted on CRP lands the CRP Pilot Program would be worth the following amount to the CVBP:

- $4.16 million/yr, or about $20.81/ton of switchgrass for an average annual yield of 4 tons/acre; or
- $2.77 million/yr, or about $13.87/ton of switchgrass for an average annual yield of 6 tons/acre

These amounts would translate to an incentive of about 1.5 ¢/kWh for an average annual yield of 4 tons/acre, or about 1.0 ¢/kWh for an average annual yield of 6 tons/acre. Since the program is based on a per acre rental payment, the value of this program per kWh decreases with increasing yield (increased yields reduce the number of acres required to produce the needed biomass).

Exhibit 3-1: Counties within 70-miles of OGS, Listed by NASS Crop Reporting District

East Central Iowa	Central Iowa	South Central Iowa		Southeast Iowa	
Benton	Jasper	Appanoose	Monroe	Davis	Louisa
Iowa	Marshall	Clarke	Warren	Des Moines	Mahaska
Johnson	Polk	Decatur	Wayne	Henry	Van Buren
Linn	Poweshiek	Lucas		Jefferson	Wapello
Muscatine	Story	Madison		Keokuk	Washington
	Tama	Marion		Lee	

Exhibit 3-2: CRP Acreage and Average Land Rental Rates for Counties in Project Area

County in East Central Iowa NASS Crop Reporting District	Total CRP Acres	Avg. Rental Rate
Benton	16,407.8	$117.44
Iowa	39,799.5	$102.28
Johnson	22,149.2	$111.02
Linn	13,112.6	$113.44
Muscatine	14,181.5	$118.52
Subtotal - Counties Listed Above	105,650.6	$110.03
Subtotal - Other Counties in District	98,183.4	
Total - East Central Iowa District	203,834.0	

County in Central Iowa NASS Crop Reporting District	Total CRP Acres	Avg. Rental Rate
Jasper	17,110.8	$106.10
Marshall	10,031.2	$115.05
Polk	4,140.7	$122.59
Poweshiek	27,065.1	$103.46
Story	5,312.6	$136.63
Tama	28,351.4	$110.29
Subtotal - Counties Listed Above	92,011.8	$110.10
Subtotal - Other Counties in District	37,481.2	
Total - Central Iowa District	129,493.0	

County in South Central Iowa NASS Crop Reporting District	Total CRP Acres	Avg. Rental Rate
Appanoose	27,828.8	$73.17
Clarke	38,286.0	$68.76
Decatur	42,854.2	$65.05
Lucas	38,462.5	$74.94
Madison	20,757.2	$80.41
Marion	29,367.5	$87.77
Monroe	26,678.9	$73.26
Warren	30,281.1	$88.49
Wayne	59,127.1	$69.28
Subtotal - Counties Listed Above	313,643.3	$74.34
Subtotal - Other Counties in District	90,478.3	
Total - South Central Iowa District	404,121.6	

County in South East Iowa NASS Crop Reporting District	Total CRP Acres	Avg. Rental Rate
Davis	43,689.9	$76.03
Des Moines	7,484.1	$117.81
Henry	25,691.4	$100.24
Jefferson	36,194.5	$96.91
Keokuk	55,827.8	$105.06
Lee	16,905.5	$99.53
Louisa	16,380.5	$121.05
Mahaska	31,289.4	$107.20
Van Buren	29,817.3	$77.95
Wapello	20,149.3	$95.04
Washington	40,910.1	$117.43
Subtotal - Counties Listed Above	324,339.8	$99.32
Subtotal - Other Counties in District	0.0	
Total - South East Iowa District	324,339.8	

Total Project CRP - Counties in 70 mile radius	**835,645.5**	**$92.49**
Total Project Area - 70 mile radius (acres)	**9,847,040.0**	
CRP Lands Percent of Total Project Area	**8.5%**	
High Average Rental Rate:		**$136.63**
Low Average Rental Rate:		**$65.05**

3.2 Switchgrass Delivered Costs

The analysis presented in chapter 4 provides the required breakeven switchgrass delivery price for a wide range of project scenarios. The "required breakeven delivered price" estimated for each scenario considered in chapter 4 is the average amount that Prairie Lands could afford to pay its independent contractors for producing, storing, and delivering switchgrass to OGS while allowing the entire project and all partners to financially break even. The present subsection discusses several scenarios for switchgrass fuel production, storage, handling and delivery costs based on information from a combination of the following sources: Iowa State University reports, Oak Ridge National Laboratory reports, and recent hay market sale prices. These scenarios are summarized in Exhibit 3-3. These scenarios can be compared to the "required breakeven delivered price" estimates presented in chapter 4 so the reader can know the farm- and delivery-side conditions that must be achieved in order to make each of the scenarios in chapter 4 commercially feasible (under breakeven conditions). Subsections 3.2.1 to 3.2.4 discuss details regarding how the delivered costs in Exhibit 3-3 were estimated. Readers not interested in those details should review Exhibit 3-3 and then skip ahead to section 3.3.

Exhibit 3-3: Summary of Switchgrass Delivered Cost Scenarios*

Fuel Delivery Scenario Name	Estimated Ave. Delivered Cost	Scenario Description
"Low"	$40/ton	This is the assumed as the lowest feasible average annual delivered switchgrass cost. Based on Oak Ridge National Lab estimates, switchgrass supplies greater than 200,000 tons/yr. could be produced and delivered in Iowa at this price or lower. Estimated statewide quantities that could be available at $40/ton are about *35 times* the 200,000 ton/yr. amount of switchgrass needed to commercially cofire at OGS.[14] Appendix H shows the range of recent Iowa hay market prices for low-end (fair quality) hay. Auction prices ranged from $40 to $60/ton.
"Low-Medium"	$52/ton	6 ton/acre/yr average yield, a low land charge ($25/acre), all acres get CRP Pilot Program benefits, and low storage costs (storage on crushed stone under re-useable tarps)
None**	$54/ton	6 ton/acre/yr average yield, a high land charge ($100/acre), all acres get CRP Pilot Program benefits, and low storage costs (storage on crushed stone under re-useable tarps)
None**	$61/ton	6 ton/acre/yr average yield, a high land charge ($100/acre), all acres get CRP Pilot Program benefits, and high storage costs (steel sheds)
"Medium-High"	$68/ton	4 ton/acre/yr average yield, a high land charge ($100/acre), all acres get CRP Pilot Program benefits, and high storage costs (steel sheds)
"High"	$92/ton	4 ton/acre/yr average yield, a high land charge ($100/acre), no CRP Pilot Program benefits, and high storage costs (steel sheds)

* Unless noted otherwise, all tons are implied to be "wet" tons, with moisture content less than 15% by weight.
** These scenarios are not presented by name in Section 4 tables and are therefore labeled "None" here. They are provided in this table as two additional moderate cost production and delivery scenarios.

[14] Walsh, Marie E., et. al., *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*, Oak Ridge National Laboratory, Oak Ridge, TN, April 30, 1999, Updated January, 2000.

3.2.1 Production Cost

The production cost is the farm gate cost and it includes the establishment costs, reseeding costs, operating expenses, pre-harvest machinery operations, harvesting expenses, and the land charge. Establishment costs are associated with planting the switchgrass crop, and they occur in the first year. Reseeding costs occur in the second year, but it depends on the strength of the stand, so this analysis assumes that there is a 25% probability that reseeding will be needed. Since the crop is not ready for harvest until year 2 or 3, both the establishment and reseeding costs are deferred to year 3, when the farmer receives revenue from the crop. The farmer has to borrow money during the first two years, so these costs are prorated at an 8% interest rate. The harvesting expenses begin in year 3 and are the most expensive portion of the production cost.

Exhibit 3-4 shows the range of production costs based on varying yield and cost of land ("land charges"). The other production cost components listed above are not delineated in this table because they are a function of the crop yield. Results show that the lowest production cost is $44/ton (at 6 ton/acre yield and low land charge) and the highest is $72/ton (at 4 ton/acre yield and high land charge) (Duffy and Nanhou, 2001).

Switchgrass Production Process

<u>Establishment</u> (yr.1)
- Seeding
- Disking
- Harrowing/Mowing
- Applying lime, fertilizer, herbicide, etc.
- Cost is deferred to year 3; pro-rated at 8% interest rate over 11 years

<u>Growth</u> (yr. 2)
- Re-seeding (25% probability)
- Applying fertilizer, herbicides
- Cost is deferred to year 3; pro-rated at 8% interest rate over 10 years

<u>Harvesting & Baling</u> (beginning in yr. 2 or 3; continuing for next 10 yrs.)
- Applying fertilizer
- Mowing
- Raking
- Baling
- Staging and loading
- Costs are incurred for current year, from years 1 and 2, and for next 10 years

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= Switchgrass production cost (including land charge)

Exhibit 3-4: Summary of Switchgrass Production Costs

Average Annual Switchgrass Yield (tons/acre)	Land Charge * ($/acre)	Production Cost ($/ton)
6	$25	$44
4	$25	$53
6	$100	$57
4	$100	$72

* These values were obtained from recent ISU research; they represent low and high average land costs that may be applicable for the project.

3.2.2 Storage Cost

A portion of the harvested switchgrass can be immediately delivered to OGS during harvesting season (Sep., Oct., Nov.). That which can't be delivered directly from the farm to OGS will be stored on the farm or at an intermediate storage facility until it is used during the remaining months (Dec. – Aug.). OGS is usually shut down for maintenance during the month of October, so it operates for only eleven months of the year. Therefore, up to 18% of the time (2 months ÷ 11 months) the switchgrass could be sent directly from the field to the power plant (during

September and November). It would be retrieved from on-farm or intermediate storage the remaining 82% of the time.

Storage costs are estimated to range from $8.50 to $17/ton, depending on the method used to protect the switchgrass from the weather. (Duffy, 2002) The lowest cost option is storing the switchgrass outside under reusable tarp on crushed rock. Most of the estimated cost associated with this option is attributed to an estimated 7% dry matter loss (switchgrass damaged due to exposure to the elements). Other storage options include storing it outside unprotected (estimated to result in 15% dry matter loss) or under open-sided pole-framed structures (estimated to result in 4% dry matter loss). The option that would provide the most protection from weather and therefore the least dry matter losses would be storing the switchgrass inside pre-manufactured steel storage sheds. This option would cost about $17/ton and, to date, is the storage method preferred by Prairie Lands because it requires the fewest number of production acres (due to a minimum amount of dry matter loss during storage) and will maintain the switchgrass in good condition for an extended period of time (i.e., greater than one year, as has been needed for stockpiling switchgrass for cofire test campaigns). Minimizing dry matter losses results in lower required production acreage and is therefore very important, especially during early stages of the project. Since 82% of the switchgrass has to be stored at the farm, the storage costs range from a low of $7/ton (82% * $8.50/ton) for the reusable tarp option to $14/ton (82% * $17/ton) for steel sheds.

3.2.3 Handling and Delivery Cost

The bale handling charge is $2/ton and the average cost for transporting the switchgrass 30 miles is estimated to be $4/ton. (Duffy, 2002) This yields a total handling and delivery cost of $6/ton. Bale handling follows this process:

1) Staging at the farm
2) Loading on to a truck and hauling to a farm storage facility
3) Unloading off the truck and stacking
4) Reloading for the final haul to the power plant

3.2.4 Calculation of Switchgrass Delivered Cost

Two types of land are targeted to produce switchgrass for this project: CRP and non-CRP land. In both cases, it is assumed that the farmer fully owns the land—he has no outstanding payments left. In addition, we have assumed that switchgrass farming will have to be at least as profitable as alternative uses of the land. The delivered cost of switchgrass is equal to the production cost plus storage, handling and delivery costs minus the CRP rental payment benefit. The CRP rental payment benefit, discussed below, represents the total land charge adjusted for both the pilot program terms and crop yield. Estimated delivered costs for yields ranging from 1.5 to 6.0 tons per acre per year, land rents ranging from $25 to $100 per acre per year, and with or without the CRP pilot program payments are provided in Appendix J. Key assumptions and details on how these costs were calculated are provided below.

If the switchgrass is grown on CRP land, the farmer receives a partial CRP rental payment during harvest years. According to the rules of the CRP Pilot Program for the Chariton Valley Biomass Project, the rental payment received during the switchgrass harvest year will be 90% of the normal CRP payment (i.e., the harvest year payment will be 90% of the rental payment the farmer would receive for leaving the land fallow). If this CRP land were not used for switchgrass production, then it would be left fallow, so growing switchgrass has to be at least as profitable as the CRP payment for the farmer to find it appealing. Therefore the switchgrass farmer on CRP land will need to recover his production costs and the portion of the CRP payment that he loses for harvesting biomass.

For non-CRP land, it is assumed that the land is fully owned by the farmer who provides the switchgrass to Alliant, but the farmer pays a contractor for actually growing the fuel. The contractor gets paid for his time and materials. To make this a worthwhile endeavor, the farmer needs to recoup a land charge that is equivalent to what he would get from row crop land.[15]

In this analysis, the CRP rental payment or the land charge is considered a farmer's profit.[16] In deriving the production cost, all operations are assumed to be performed by contractors. If the farmer has the time and equipment needed for growing and harvesting switchgrass, he could potentially gain higher profits (or reduce his delivered price) by performing most of the production work himself. The distinction between CRP and non-CRP land is important because it is assumed that farmers on CRP land can offer a lower delivered price than farmers who provide switchgrass grown on non-CRP land. The farmer with switchgrass on non-CRP land is at a disadvantage because he cannot lower his delivered price by a similar amount.

Exhibit 3-3 lists the major elements of delivered switchgrass cost. The delivered switchgrass cost is calculated by subtracting the CRP rental payment benefit from the production cost and then adding in storage, handling and delivery costs. "Full CRP benefits" refers to growing all the switchgrass on 50,000 acres of CRP land. As summarized in Exhibit 3-3, four delivered switchgrass cost scenarios are outlined below:

- "*Low*" represents the lowest delivered cost of switchgrass for Iowa produced by Oak Ridge National Laboratory.[17]
- "*Low-Medium*" represents a 6 ton/acre yield, a low land charge ($25/acre), full CRP benefits, and low storage costs
- "*Medium-High*" represents a 4 ton/acre yield, a high land charge ($100/acre), full CRP benefits, and high storage costs (steel sheds)
- "*High*" represents a 4 ton/acre yield, a high land charge ($100/acre), no CRP benefits, and high storage costs

Existing hay and straw markets were used to determine the validity of these costs; research showed that the average prices (on a per ton basis) for grass, straw, alfalfa, and alfalfa mix spanned a range similar to that covered over the range of the "Low" to the "High" cases noted above and in Exhibit 3-5. Refer to Appendix H for further information on the hay and straw market data.

[15] The most profitable farming scenario in Southern Iowa is "corn following corn" (planting corn annually in the same field). Its production cost ranges from $328 to $406/acre, which includes a land charge between $105 and $145/acre (Duffy and Smith, 2002)

[16] Additional profit margins above *normal* profits were not considered in the "breakeven" analysis described in this report.

[17] The "Low" fuel delivered cost is estimated based on the ORNL report "Economic Analysis of Energy Crop Production in the U.S" by Marie Walsh, and Daniel De La Torre Ugarte, et. al. This report states that switchgrass can be supplied at a price around $40 per ton.

Exhibit 3-5: Summary Table for Estimated Delivered Switchgrass Costs ($/ton)[18]

Production Cost	CRP Rental Payment Benefit	Storage Cost	Handling & Delivery	Delivered Switchgrass Cost
$44	$5	$7	$6	$52 (Low-Med)
$72	$24	$14	$6	$68 (Med-High)
$72	$0	$14	$6	$92 (High)

The production costs shown in Exhibit 3-5 are obtained from Exhibit 3-4. As discussed in section 3.2.1, the land charge is assumed a low of $25/acre or a high of $100/acre. The land charge is used to calculate the CRP rental payment benefit, as shown in Equation 3-1.

Equation 3-1:

$$\text{CRP Rental Payment Benefit (\$/ton)} = \frac{(LC * \text{Pilot }\%) + K}{Y}$$

Where:

LC = Land charge ($/acre)

K = Amount of the land charge included in the establishment and reseeding portion of the production cost ($8/acre)[19]

Pilot % = Biomass pilot program rate for energy crop production (90%)

Y = Average yield of switchgrass fields

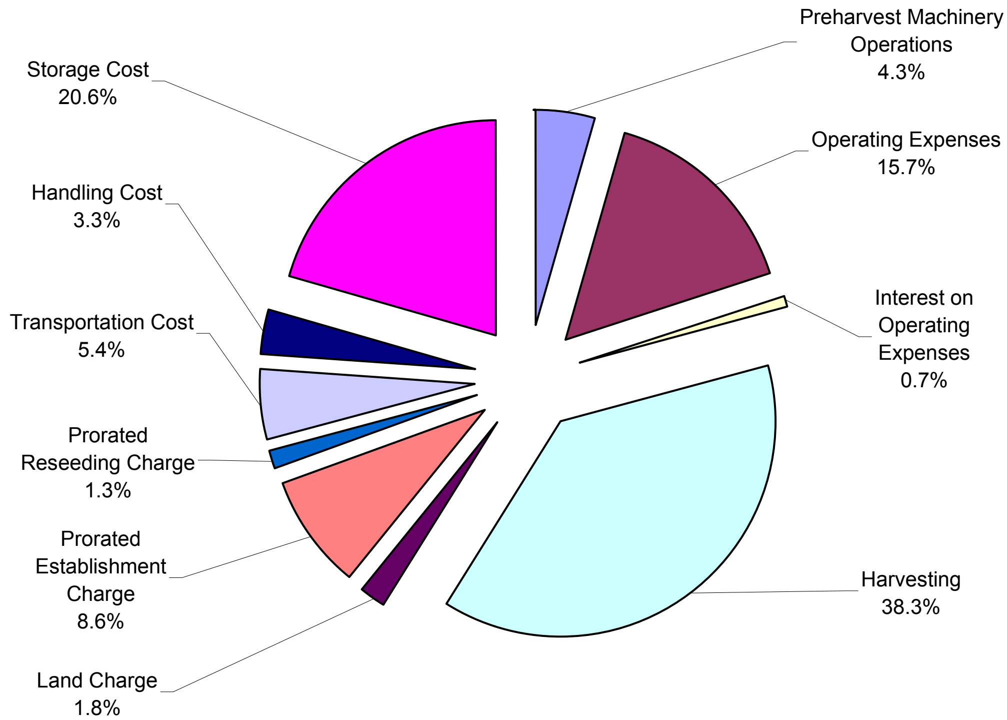
The "Low-Med" delivered cost scenario has a $5/ton CRP rental payment benefit {[($25 * 90%) + $8]/6}. The "Med-High" delivered cost scenario has a $24/ton CRP payment reduction benefit {[($100 * 90%) + $8]/4}. The "High" delivered cost scenario does not have a CRP payment reduction amount because it is assumed that the switchgrass is grown on non-CRP land. Results show that the CRP payment can significantly lower the cost of providing switchgrass fuel (by as much as $24 per ton).

Exhibit 3-6 displays the relative weight of each delivered cost component; the values represent the "Med-High" scenario for delivered cost of switchgrass fuel ($68/ton). Harvesting and storage costs together comprise nearly 60% of the total cost and represent significant opportunities for production cost savings.

[18] Antares Group assumes that the "Low" price stated in the ORNL report uses some of the strategies that will be mentioned in Chapter 5 for reducing the cost lower than the $52/ton. It is not included in Exhibit 3-5 since the details of the computations for the delivered cost are not fully explained within the report.

[19] $8/acre is estimated based upon results calculated in the economic study "Cost of Producing Switchgrass for Biomass in Southern Iowa" by Duffy and Nanhou.

Exhibit 3-6 Delivered Cost Components, at $68/ton



3.3 Determining the Cost of Electricity (COE) for Switchgrass Power

The goal of this analysis is to determine the circumstances under which the switchgrass cofiring project can be commercially viable at OGS. Identifying these conditions requires a comparison of switchgrass generation with the other major generation options in Iowa. In this project, the coal portion of cofiring dominates the switchgrass portion, so using a combined/overall cofiring COE would mask the effect of introducing switchgrass at OGS.[20] Therefore, to isolate the switchgrass portion and fairly compare it with its competition, we calculated the COE from *the switchgrass portion of the cofiring operation* ("switchgrass COE") alone.[21] Under the status quo, the competition for the switchgrass cofiring project is coal-only operation at OGS. In the case where there is an RPS requirement or an increased demand for Alliant's green power offerings, we compare the switchgrass COE to a range of COEs for wind power in Iowa.

In determining the switchgrass COE, *all operational cost changes at OGS due to the cofiring project are charged to the switchgrass COE*. For example, if there is a slight decrease in boiler efficiency caused by the cofiring operation, increased coal purchases (per unit of power output) are incorporate into the switchgrass COE. Changes in ash management costs are also included in the switchgrass COE, although more than 95% of the ash will be coal ash during the cofiring operation. To reiterate, the switchgrass COE is not the overall cofiring COE from OGS.

This section will describe how we determined the annual costs related to the switchgrass COE. This COE is calculated by dividing the total annual costs associated with the cofiring project by the annual power generated from the switchgrass portion of the project. The annual costs associated with the switchgrass portion of the cofiring operation are:

- Delivered cost of switchgrass fuel
- On-site capital costs (assumed zero)
- Fixed O&M costs
- Variable O&M costs (exclusive of fuel)
- Changes in performance due to cofiring
- Risk factor

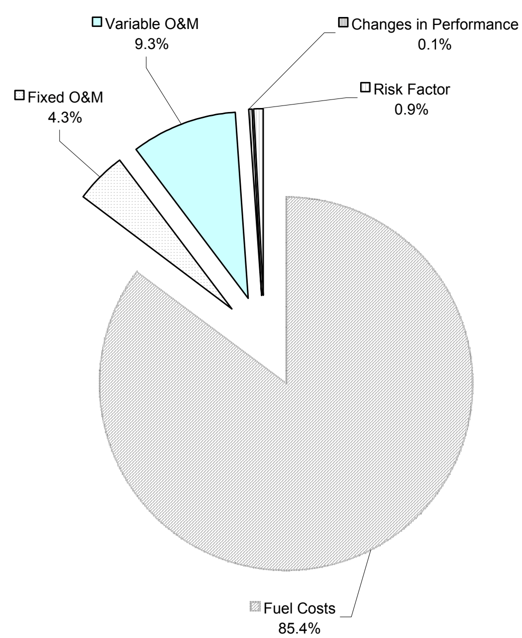


Exhibit 3-7: Switchgrass COE by Cost Component, at $68/ton Delivery Price

Exhibit 3-7 shows each cost's proportional impact on the switchgrass portion of the cofiring COE. The costs are based upon the "Med-High" unsubsidized fuel delivery price of $68/ton.

[20] Cofiring uses two fuels, which makes it difficult to identify each fuel's impact if one examines the overall COE for the power plant. This project magnifies this situation because switchgrass comprises only 6.2% of the heat input to the boiler, and coal comprises the remaining 93.8%.

[21] This COE does not represent the overall/combined cofiring COE at OGS. The overall cofiring COE is calculated by dividing the total costs of both coal and biomass operations by the total net power generated at OGS during cofiring.

3.3.1 Switchgrass Fuel Cost

Fuel purchases will be the largest component of the project's annual costs. The "Medium-High" delivered fuel price is $68/ton (from Exhibit 3-5) and the annual switchgrass consumption is 200,000 tons/yr. Thus, the total annual fuel cost will be $13.6 million.

3.3.2 On-Site Capital Costs

The initial cost for the switchgrass receiving system and processing center was estimated to be $15,308,900; the automated stack and reclaim system using the overhead bridge crane system comprises approximately 10% to 15% of this cost (BCCE, 2001). If this initial cost is divided by the 35 MW biopower portion of the total generation (5% of 726 MW), it yields a capital cost-to-power produced ratio of $439/kW of installed biopower.[22]

This project's capital costs are reduced by the proposed DOE cost share funds. The total DOE cost share amount is assumed to be $15.3 million. Thus, the amount financed for this project's capital costs is assumed to be zero in the results presented in this report. If part of the capital costs are financed by one of the partner organizations, for each $1 million financed the annual debt service for a twenty-year loan financed at 8% would be $101,852. The required breakeven delivered fuel prices presented in the executive summary and section 4 would have to be reduced by $0.51 per ton to compensate for each $1 million of partner investment under these financing terms.

3.3.3 Fixed O&M Costs

This category represents the additional fixed O&M costs that are associated with switchgrass operation. It includes: additional employees, maintenance, and administration and insurance. The project is expected to require three additional employees to supervise the automated crane system and to drive the spotter trucks; compensation for these three employees will add $225,000 to the cost of producing switchgrass power. Annual maintenance costs are estimated to be 2% of the project's initial capital cost (Easterly, 1994); this equates to approximately $306,000. An additional two people will be required to handle the administrative duties, which include handling trucking logistics and processing payments for the delivered switchgrass. The compensation for these two people will add $150,000 to the project cost annually. Adding these costs together results in a total fixed O&M cost of $681,000.

3.3.4 Variable O&M Costs (exclusive of fuel)

It is assumed that the switchgrass produced power will have the same variable O&M costs on a $/kWh basis as the existing coal-fired operation. This category includes costs such as maintenance of the boiler, turbine, and cooling tower. It is assumed that the switchgrass project will replace 6.2% of the existing coal generation (equal to the annual heat input percentage). If the variable O&M cost for OGS' existing operations is $24 million/yr., the estimated annual cost for switchgrass O&M is approximately $1.48 million (6.2% * $24 million), or about $0.00537/kWh.

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[22] As a comparison, EPRI estimates that the capital cost for a separately-fed biomass cofiring operation is between $175/kW and $300/kW. These costs are based on wood-fired systems that are typically required to receive 2 inch minus wood chips and process them into ¼ inch or 1/8 inch minus material (Hughes, 1998). Equipment requirements for the CVBP are more expensive due to the need to receive, store, manage, and process large bales of material instead of 2 inch minus chips.

3.3.5 Changes in Performance

Performance changes includes costs associated with the following: anticipated decreased boiler efficiency and increased fouling, unanticipated efficiency losses, a risk factor, increased parasitic load, losses in ash sales, and ash disposal costs. Alliant Energy anticipated an increased fouling factor of 0.1% and a decreased boiler efficiency of 0.07%. These efficiency losses result in annual increases of $10,000 and $7,500, respectively. The previous cofiring tests show for a 6.2% cofiring operation on a heat basis, the boiler efficiency will decrease 0.17% (Plasynski et. al., 1998). From this cofiring experience, an estimated extra annual cost of $7,500 was added for unanticipated inefficiency losses. These estimates assume that the parasitic load of OGS will remain the same. If ash sales remain the same, the total cost associated to the changes in performance is approximately $25,000. Chapter 4.0 discusses the ramifications of lost ash sales.

3.3.6 Risk Factor/Contingency

A $150,000 risk factor was included to compensate Alliant Energy. This is viewed as an incentive for Alliant to participate in this project.

3.3.7 Summary of Annual Project Costs and Resulting COE

Cost Component	Annual Cost
Switchgrass fuel cost (@ $68/ton)	$13,600,000
On-site capital costs	$0
Biomass related O&M costs	$681,000
Existing coal O&M costs	$1,480,000
Changes in boiler performance	$25,000
Risk factor	$150,000
Annual Project Cost	**$15,936,000**

Equation 3-2 calculates the annual switchgrass generation and Equation 3-3 uses this value to calculate the switchgrass COE.

Equation 3-2:

$$\text{Annual Switchgrass Generation (kWh/yr)} = \frac{\text{Switchgrass consumption (lb/yr)} * \text{Switchgrass HHV (Btu/lb)}}{\text{OGS net heat rate + heat rate increase (Btu/kWh)}}$$

Switchgrass consumption = 200,000 tons/yr (400,000,000 lbs/yr)
Switchgrass HHV = 7,428 Btu/lb (Amos, 2002)
OGS net heat rate = 10,828 Btu/kWh (Alliant Energy, 2002)
Heat rate increase = 6 Btu/kWh (Plasynski, 1998; see section 3.3.5)

Using these assumptions, this project will produce approximately 275,360,000 kWh/yr from switchgrass generation.

Equation 3-3:

Cost of Electricity for Biopower ($/kWh)
= (Annual project cost)/(Annual biopower generated)
= $15,936,000/275,360,000 kWh
= **$0.058/kWh** for a fuel cost of $68/ton

3.4 Cost of Electricity (COE) of Competition

Switchgrass will have to compete with either coal or wind power. The current COE at OGS is based on coal-only power and it is used as a benchmark for determining the maximum delivered price of switchgrass. The wind power COE is used to compare the switchgrass project's COE against the other predominant renewable energy source in Iowa.

3.4.1 Coal Power at OGS

The COE at OGS was determined by dividing the annual expenses for the coal operation by the annual amount of electricity generated. The annual COE for coal power (from fuel only) was calculated by using Equations 3-4, 3-5, and 3-6. OGS provided the following inputs:

Cost of Coal:	\$0.90 /MMBtu
Capacity Factor (CF):	75.6%
HHV, Coal:	8,400 Btu/lb
Net Plant Capacity (NPC):	675MW
Net Plant Heat Rate (NPHR):	10,828 Btu/kWh

Equation 3-4:

$$\text{Annual Coal Consumption (lb/yr)} = \frac{\text{NPC x CF x 8760 (hrs/yr) x 1000 (kW/MW) x NPHR}}{\text{HHV Coal}}$$

Equation 3-5:

$$\text{Total Coal-Power Generation (kWh)} = \frac{\text{Annual Coal Consumption (lb/yr) x HHV Coal (Btu/lb)}}{\text{Net Plant Heat Rate (Btu/kWh)}}$$

Equation 3-6:

$$\text{Coal COE (fuel component) (¢/kWh)} = \frac{\text{Annual Coal Consumption x Cost of Coal}}{\text{Total Coal-Power Generation}}$$

Based on these inputs and equations, the fuel-only COE for coal-power is calculated to be approximately 1.0 ¢/kWh. Our analysis assumes debt service on all capital cost is zero due to the age of the power plant. Another 0.5 ¢/kWh is added to the coal power for non-fuel related O&M costs for a total busbar COE of 1.5 ¢/kWh. The additional 0.5 ¢/kWh is an industry estimate for large-scale coal power plants. (EIA, 1996)

3.4.2 Wind Power in Iowa

Wind COE numbers are highly dependent upon the wind resource potential (wind classification zone), project ownership structure, and the project financing method. Since the type of ownership structure and financing are unknown, the competitive COE number for wind power will be represented by a maximum and minimum amount. These numbers represent the range of potential COEs for wind power in Iowa; they are not based on an existing wind farm operation in the state. Although this analysis was based primarily on a source that used wind power technology costs from 1996 and assumed a base year of 1997, more recent reference materials were used to verify that the range discussed below is still valid for Iowa wind projects (USDOE and EPRI, 1997; Wind, 2000).

Both the upper and lower bounds of the range for wind power production in Iowa are based on the following assumptions (Wiser and Kahn, 1996):

1) The power would be produced within a class 4 zone such as the northwestern portion of Iowa.
2) The wind farm capacity would be 50 MW with a 30% capacity factor.
3) Capital costs would be $1000 per installed kW, and O&M expenses would be $17/kW-yr.
4) Project life is 20 years with an inflation rate of 3.5% and a discount rate of 10%.

The upper bound for the wind COE is 4.9 ¢/kWh; this is referred to as "wind-high." This calculation is based on the following major assumptions (Wiser and Kahn, 1996):

1) The wind farm will be privately owned with project financing.
2) The debt fraction of 46.8% will be amortized over a 12-year period at a 9.5% interest rate.
3) The equity fraction of 53.2% invested in the project will need a minimum return of 18%.[23]
4) The production tax credit of 1.5 ¢/kWh will be applied.[24]
5) Wind equipment will be depreciated over a 5-year period, and the land cost will be depreciated over a 15-year period.

The lower bound for the wind COE is 2.9 ¢/kWh; this is referred to as "wind-low." This calculation is based on the following major assumptions (Wiser and Kahn, 1996):

1) The wind farm will be publicly owned and internally financed.
2) The annual Renewable Energy Production Incentive (REPI) will be awarded.
3) Capital costs will be amortized over a 20-year period at a 5.5% interest rate.

The next chapter of this report derives estimated COEs for Alliant Energy and applies project revenue generating incentives. The COE numbers for switchgrass with and without incentives will then be compared against coal and wind generated power sources.

[23] The 18% return on equity is slightly higher than the 17% return on equity required for Independent Power Producers as described in the Project Financial Evaluation Section of the 1995 Renewable Energy Technology Characterization.
[24] The 1.5 ¢/kWh is in 1992 dollars, but we use 1.8 ¢/kWh for the switchgrass power COE calculations, which is adjusted for inflation to 2001 $US.

4.0 PRELIMINARY FINANCIAL ANALYSIS: RESULTS AND CONCLUSIONS

4.1 Factors Affecting Project Viability

The three contractual parties involved in a commercial Chariton Valley Biomass Project would be the farmers (the fuel suppliers), Prairie Lands Bio-Products Inc. (grower cooperative organization, fuel supply integrator and processor), and Alliant Energy Corporation (the fuel purchaser). Each faces unique conditions that could determine the project's overall success: total capital cost, switchgrass storage options, delivered cost of switchgrass fuel, ash market impacts, availability of external incentives and new policies, and power plant operations at OGS. Refer to Chapter 3.0 for a detailed explanation of these factors as considered in this analysis.

Project success, however, is not based solely on the cost inputs. To be commercially successful, biomass cofiring at OGS has to be competitive with other generation alternatives in Iowa: either 1) existing coal-fired power at OGS, or 2) Iowa wind power. Comparing the switchgrass cost of electricity (COE) (section 3.3) to the existing coal COE at OGS represents the competitive environment in the absence of an increased state renewables mandate. If there is no increased demand for renewable energy in the state, then biomass cofiring must generate electricity at a cost less than or equal to existing coal-fired power at OGS. Since Iowa recently had a requirement for the installation of 105 MW of renewable capacity (this requirement has already been fulfilled through installation of new wind projects), and Iowa's *2002 Energy Plan Update* includes a recommendation for increasing that amount to ten percent of the state's electric generation by 2010, a comparison to Iowa wind power allows the 35 MW of biopower produced by switchgrass to be evaluated in a competitive environment that is limited to in-state renewables. Two wind options are included to represent different financing structures. The cost of wind power based on municipal financing is referred to as "wind-low" in the Exhibits below, and is estimated to be 2.9 ¢/kWh. The cost of wind power based on project (independent power producer) financing is referred to as "wind-high" in the Exhibits below, and is estimated to be about 4.9 ¢/kWh. Based on a detailed recent study on present and future economics of wind generation in Iowa, the average (or most likely) cost of electricity from wind power installed in 2002 in Iowa would be about 3.9 ¢/kWh. (Wind, 2000)

This chapter discusses the results of the preliminary analysis conducted using the economic analysis model developed by Antares Group. This model was developed to help the contract parties understand their respective positions so that before serious contract negotiations begin, project partners can determine common and important objectives (i.e., so partners can determine what things must be accomplished before serious negotiations can occur). This analysis studied the conditions necessary for project viability—identifying how switchgrass can be a competitive fuel option and how Alliant Energy can generate cofired electricity at a competitive price, given the alternative generation options. The conditions for project viability are grouped by: 1) the project's impact on OGS's existing ash markets, and 2) the available external incentives such as SO_2 emissions credits, the production tax credit, and green power sales. [25] Supporting charts and tables are provided in the appendices.

4.1.1 Cofiring Project Impact on Existing Ash Markets

The analysis began by establishing scenarios that represent likely project conditions. Two scenarios were chosen to evaluate how impacts on the ash market can alter the project's viability:

[25] The term "external" incentives is used to refer to incentives that would lead to increased revenue from parties other than the contract parties for the Chariton Valley Biomass Project.

a base case and a lost ash market case. The economic model can quickly evaluate any situation between these two extremes—i.e., a partial loss of existing ash markets.

Base Case Scenario

The base case scenario assumes that there will be no changes in existing ash sales; OGS will be able to receive the same amount of revenue from selling cofired ash as from coal-only ash.

Lost Ash Market Scenario (Alternate #1)

This scenario assumes that there will be total loss of ash sales in the event the ash from cofiring does not meet ASTM standards and equivalent replacement markets are not found.[26] It highlights the importance of the ash market to OGS' economics. Currently, OGS generates 172,000 tons of ash a year, which it sells at an average price of [redacted]/ton; this brings in [redacted] in annual revenue. If OGS cannot sell the ash, they will have to dispose of it. Ash disposal costs average about [redacted], which equates to [redacted] in new expenses. Thus, losing the ash market plus having to dispose of the ash would cost OGS [redacted].[27]

4.1.2 Regulatory Incentives

The analysis then introduces three potential regulatory incentives. CRP payments are given to farmers to preserve lands under CRP management, SO_2 credits are part of the national credit trading market, and the PTC is for wind, closed-loop biomass and poultry litter-fired power plants. Refer to section 3.1 for a more detailed explanation of these incentives. As these incentives are applied, the switchgrass production cost or COE are affected.

The Appendix includes graphs depicting how the delivered cost of switchgrass fuel varies by the two scenarios and the effect of external incentives; the CRP payment amount is already incorporated in the delivered cost of switchgrass fuel (see Exhibit 3-3). Each graph delineates the coal, wind-low, and wind-high COEs, and three switchgrass cofiring cases:

- without any regulatory incentives
- with an SO_2 credit of 0.05 ¢/kWh[28]
- with the SO_2 credit and the PTC of 1.8 ¢/kWh (total = 1.85 ¢/kWh)

Results from the breakeven analysis are shown in Exhibits 4-4, 4-5, 4-6 and 4-7. The biomass cofiring case without any incentives is shown in the graphs in Appendix E for comparison purposes. The SO_2 credit is available today, so cofiring with this incentive alone is referred to as the "status quo" option in Exhibits 4-4, 4-5, 4-6 and 4-7. The scenario with both the SO_2 credit and the PTC, and competition with wind (for the regulatory case where there is an expanded renewables mandate in Iowa) is considered cofiring's "best" case regulatory option. In several ways, this "best" case regulatory situation is the fairest comparison for the Chariton Valley Biomass Project:

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[26] ASTM is the American Society of Testing and Materials; ASTM certifies the ash to be used in various construction applications.
[27] Data on ash sales, ash disposal, average ash content of coal, and annual heat input provided by Alliant Energy.
[28] Based on current market value of $150/ton for SO_2 credits.

- Wind projects already receive the production tax credit (which is figured into their COE in this analysis) or the equivalent Renewable Energy Production Incentive.
- The production tax credit was also intended to allow closed-loop biomass projects to qualify (the CVBP would be a closed-loop biomass project)—other restrictions that presently exclude biomass cofiring projects (even with closed-loop biomass) have resulted in minimal biomass projects qualifying for the credit compared to extensive qualification by wind projects.
- The expansion of wind capacity has been largely fueled by increased renewables mandates or by competitive evaluation versus *new* power generation projects (rather than existing, base-load, fully-amortized coal-fired power plants like OGS).

4.1.3 Green Power Markets

Green power premiums obtained via its Alliant's Second Nature program could bring additional revenue to the project. Currently, the program has three levels of participation: Nature Sentinel (25% renewable power), Eco Watcher (50% renewable power), and Earth Steward (100% renewable power). If a customer chooses the 100% green power option, he is charged a 2.0 ¢/kWh premium. The premiums are pro-rated for the 50% or 25% green power options—1.0 and 0.5 ¢/kWh, respectively.

This project is expected to produce 275,360,000 kWh of biopower annually using 200,000 tons of switchgrass per year. If Alliant is able to sell this entire amount at the 2.0 ¢/kWh premium, it could receive an annual income of $5.5 million (275,360,000 kWh/yr * $0.02/kWh). Research and experience has shown that residential customers purchase various levels of green power, not just the 100% option. However, a lack of data makes it difficult to apportion potential customers across the three options, so we assume that all green power customers will choose the same option.

Exhibit 4-1 shows how many residential green power customers will be needed if *all* of them signed on to any one of the three Second Nature program options. For example, if all of them choose the Earth Steward option, Alliant will need 29,901 green power customers, or about 8% of its total residential *Iowa* customer base to receive the $5.5 million annual income from green premiums.[29] Examining the required sales over Alliant's 796,000 residential customers in all of its service areas (Iowa, Wisconsin, Minnesota, and Illinois), subscriptions to the Earth Steward program would have to be 4% of Alliant's total residential customers to consume all of the CVBP's power output. These amounts would be in addition to other renewable projects that provide power for Alliant's Second Nature program. As a comparison, the customer participation rates for the top ten utility green pricing programs range from 3% to 7%, with a premium ranging from 1.0 to 1.5 ¢/kWh. (USDOE, 2002) As further discussed in chapter 5, CVBP partners should also market their green power to corporate customers, and state and federal government organizations who have already established significant renewable power purchase goals. This would greatly reduce the amount of residential subscriptions required to sell all of the project's power.

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[29]The average residential Alliant Energy customer in Iowa consumes 9,209 kWh/yr, and approximately 393,000 Iowans are Alliant Energy residential customers.
<u>Calculation (for # customers)</u>:
275,360,000 kWh/yr ÷ (9,209 kWh/yr.-customer x 100% Renewable) = 29,901 customers
<u>Calculation (for %)</u>: 29,901 ÷ 393,000 = 30.4%

Exhibit 4-1: "*Second Nature*" Residential Customers Required, at Three Program Levels
(*Second Nature* is the name of Alliant's green power program.)

	Nature Sentinel (0.5 ¢/kWh premium)	**Eco Watcher (1.0 ¢/kWh premium)**	**Earth Steward (2.0 ¢/kWh premium)**
Residential Customers Only			
# of customers required to consume all CVBP power	119,602	59,801	29,901
% of Alliant's ***Iowa*** residential customer base	30%	15%	8%
% of Alliant's ***Total*** residential customer base	15%	8%	4%

NOTE: Numbers in this table assume no sales to non-residential customers. Sales to non-residential customers could greatly decrease sales requirements to residential customers.

Exhibit 4-4 provides the maximum breakeven delivered price needed for the switchgrass COE to compete with coal, wind-low, and wind-high; these are evaluated based on the regulatory incentives available and the portion of the maximum annual income ($5.5 million) from green power sales—"green power income" (GPI). For example, if the project gets the SO_2 credit and 100% of the GPI, then the delivered switchgrass price would have to be $38/ton for all contractual parties to break even (i.e., obtain *typical* profits) with coal in the base case.

As treated in this analysis, the GPI does not alter the switchgrass breakeven points for the wind options because this analysis assumes that wind and biomass power will receive equal green power premiums. Exhibit 4-4 shows that the breakeven prices for the wind options do not change with the presence of a GPI, with the exception of the wind-low options with 100% GPI. These values are the same as for the coal cases ($38/ton and $18/ton without the PTC; $62/ton and $43/ton with the PTC). This is because Iowa's electricity industry has not deregulated, so we assume that regulators would not allow wind power to be cheaper than coal-fired power and still receive a green premium.

4.2 Issues Affecting Each Party

Project viability will be based mainly on the delivered cost of switchgrass (the largest component of the COE), the incentives available, and the competing generation options. This section shows when switchgrass can be competitive with the alternative generation options, for a given project condition (0% or 100% lost ash sales) and available incentives. Discussion is categorized by issues that affect the farmers, Prairie Lands, and Alliant. Exhibit 4-2 describes the primary product flows involved from one party to another, and Exhibit 4-3 describes the costs associated with the switchgrass as it changes ownership from the farmers to Prairie Lands, and from Prairie Lands to Alliant. This cost and responsibility allocation may be somewhat different during commercial operation, especially between the farmers and Prairie Lands. During commercial operation, Prairie Lands may have responsibility for some of the items shown as costs to the farmers. For example, some farmers may deliver their bales to an intermediate storage facility operated by Prairie Lands, and then Prairie Lands would transfer those bales from intermediate storage to the biomass storage and processing facility at OGS when needed. Payments for those costs would then be moved from the farmer's delivered costs to part of Prairie Lands' operating budget.

Exhibit 4-2: Summary of Primary Product Flows for Chariton Valley Biomass Project

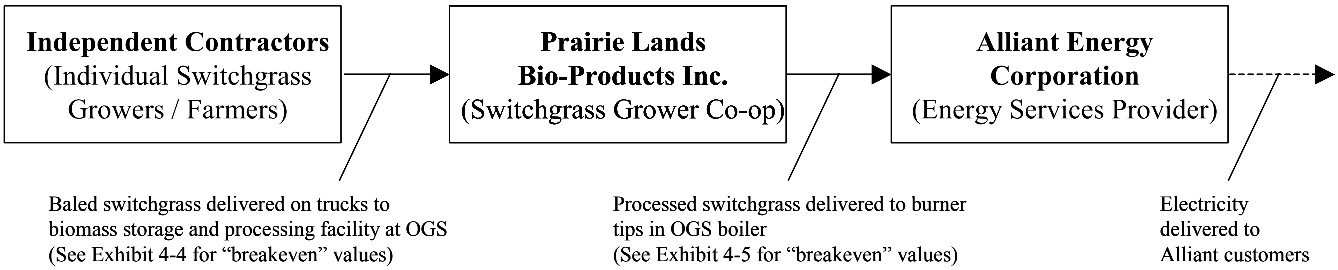
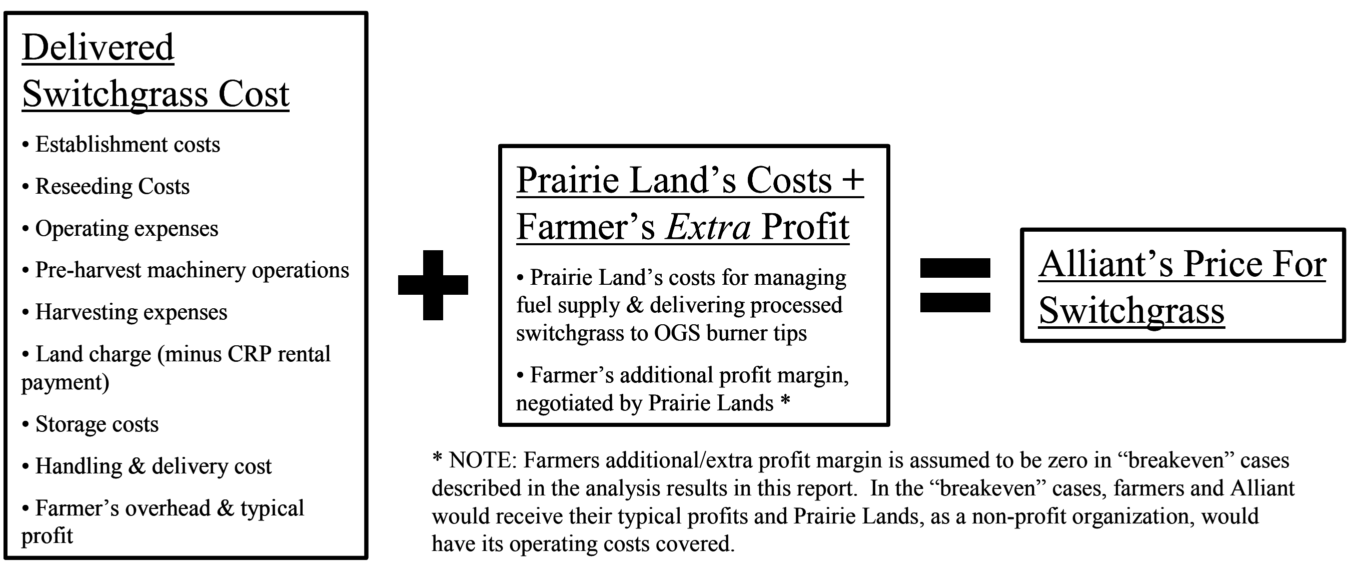


Exhibit 4-3: Summary of Delivered Switchgrass Cost and Price Components for Each Contracting Party in the Chariton Valley Biomass Project



4.2.1 Issues for Prairie Lands' Farmers

Exhibit 4-4 shows the *farmers'* breakeven price in order for the switchgrass COE at OGS to compete with coal, wind-low, wind-ave (average cost of wind power in Iowa), and wind-high under the two ash scenarios considered; the information is categorized by regulatory and financial incentives that may be available. Values in Exhibit 4-4 are at the point of receipt at the biomass proceesing facility at OGS (they are freight-on-board prices, for bales delivered on trucks to OGS). The project will be viable only if switchgrass can be delivered at a cost no greater than these various breakeven prices. Breakeven prices shown in **bold** indicate scenarios where the CVBP could be commercially viable based on the lowest-cost ($40/ton) fuel supply scenario summarized in Exhibit 3-3. As shown in Exhibit 4-3, under "breakeven" conditions farmers would have to receive payment for all of their expenses, including land rent, plus profits typical of farm contractors for each farm-related task.

Exhibit 4-4: Maximum Breakeven Delivered Switchgrass Price ($/ton) to Allow Even Competition with Coal and Wind, with Regulatory and Financial Incentives

(Prices below are for switchgrass delivered, Freight-on-Board, to the biomass facility at OGS)

		Competition Considered			
Regulatory/Financial Incentive Combination	**Ash Management Scenario**	**Coal ($/ton)**	**Wind-Low ($/ton)**	**Wind-Ave ($/ton)**	**Wind-High ($/ton)**
	"Status Quo" Regulatory Scenarios				
SO_2 alone (no GPI)	Base Case--No change	$10	$29	**$43**	**$58**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + 25% GPI	Base Case--No change	$17	$29	**$43**	**$58**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + 50% GPI	Base Case--No change	$24	$29	**$43**	**$58**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + 100% GPI	Base Case--No change	$38	$38	**$43**	**$58**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
	"Best Case" Regulatory Scenarios				
SO_2 + PTC (no GPI)	Base Case--No change	$35	**$54**	**$68**	**$82**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + PTC + 25% GPI	Base Case--No change	**$42**	**$54**	**$68**	**$82**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + PTC + 50% GPI	Base Case--No change	**$49**	**$54**	**$68**	**$82**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + PTC + 100% GPI	Base Case--No change	**$62**	**$62**	**$68**	**$82**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]

NOTES: Bold numbers in the table above represent scenarios where the switchgrass project could be commercially competitive. "SO_2" refers to SO_2 emissions credits valued at $150/ton. "PTC" refers to the section 45 production tax credit for wind and closed-loop biomass, valued at 1.8 ¢/kWh. "GPI" refers to green power incentives, and 25% GPI, 50% GPI, and 100% GPI refer to Alliant's Second Nature green power offerings that allow customers to buy electricity with a 25%, 50%, or 100% mix of renewable power, respectively. The overall premiums for the 25%, 50%, and 100% GPI scenarios are: 0.5 ¢/kWh, 1.0 ¢/kWh, and 2.0 ¢/kWh, respectively.

Results show that depending on the available incentives and ash management scenario, switchgrass can be delivered at a price:

- up to $35/ton and be competitive with coal, with no green power incentive
- up to $62/ton and be competitive with coal, with a 2 ¢/kWh green power incentive (this is the 100% GPI scenario in Exhibit 4-4)
- up to $54/ton and be competitive with low cost wind
- up to $68/ton and be competitive with average cost wind
- up to $82/ton and be competitive with high cost wind

4.2.2 Issues for Prairie Lands

Prairie Lands' role as the farmer cooperative will be to manage the entire fuel supply chain, receive and process the biomass and provide it to Alliant's burner tips at OGS, manage all aspects of operating the biomass storage and processing facility at OGS, and serve as the liaison between the farmers and Alliant. The administrative costs associated with these activities are incorporated into the fixed O&M project costs as discussed in section 3.3.3. Since Prairie Lands is a non-profit organization, we excluded profits for Prairie Lands in the economic analysis. We estimated that total employment of Prairie Lands would be five people—a total of three for supervising the automated crane system, performing maintenance at the facility, and driving spotter trucks, and two for handling administrative duties, including handling trucking logistics and processing payments for the delivered switchgrass. Adding these labor expenses to other estimated costs for operating the biomass facility resulted in an estimated annual operating budget (excluding switchgrass purchases) of $681,000 for Prairie Lands. So a charge of about $3.41 per ton ($681,000/yr ÷ 200,000 tons/yr) would have to be added to the costs of switchgrass delivered to the biomass facility at OGS to cover Prairie Lands' expenses.

4.2.3 Issues for Alliant Energy

During commercial operation, the difference between the actual F.O.B. delivered switchgrass costs and the actual price Alliant pays[30] for switchgrass delivered to the OGS boiler burner tips will be equal to Prairie Lands' overhead[31] for managing the fuel supply and providing processed biomass to the burner tips, plus any additional profit margin negotiated by the farmers. Based on our preliminary estimates, the cost required to cover Prairie Lands overhead would be about $3.41/ton (as discussed above). Exhibit 4-5 shows breakeven costs from *Alliant's* perspective under various scenarios, including the amount required to cover Prairie Lands' entire overhead. This table shows what is needed for the switchgrass COE at OGS to compete with coal, wind-low, wind-ave, and wind-high under the two ash management scenarios; the information is categorized by regulatory incentive. The values in Exhibit 4-5 vary from those in Exhibit 4-4 by a constant $3.41/ton—the amount required to cover estimated Prairie Lands' expenses.

[30] This would be the negotiated contract amount in the Biomass Supply Agreement between Alliant and Prairie Lands (Appendix A).

[31] In the terminology used here, the Prairie Lands "overhead" refers to all of the costs required for the nonprofit co-operative organization to manage the biomass project, maintain the processing facility at OGS, and process the biomass for use in the OGS boiler. This includes all required administration, insurance, and biomass processing facility operation and maintenance.

Exhibit 4-5 Maximum Breakeven Processed Switchgrass Prices ($/ton) to Allow Even Competition with Coal and Wind, with Regulatory and Financial Incentives
(Breakeven prices below are for *processed switchgrass provided to the OGS burner tips*)

		Competition Considered			
Regulatory/Financial Incentive Combination	**Ash Management Scenario**	**Coal ($/ton)**	**Wind-Low ($/ton)**	**Wind-Ave ($/ton)**	**Wind-High ($/ton)**
	"Status Quo" Regulatory Scenarios				
SO_2 alone (no GPI)	Base Case--No change	$13	$32	**$47**	**$61**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + 25% GPI	Base Case--No change	$20	$32	**$47**	**$61**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + 50% GPI	Base Case--No change	$27	$32	**$47**	**$61**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + 100% GPI	Base Case--No change	$41	$41	**$47**	**$61**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
	"Best Case" Regulatory Scenarios				
SO_2 + PTC (no GPI)	Base Case--No change	$38	**$57**	**$71**	**$86**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + PTC + 25% GPI	Base Case--No change	**$45**	**$57**	**$71**	**$86**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + PTC + 50% GPI	Base Case--No change	**$52**	**$57**	**$71**	**$86**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]
SO_2 + PTC + 100% GPI	Base Case--No change	**$66**	**$66**	**$71**	**$86**
	Lost Ash Market	[redacted]	[redacted]	[redacted]	[redacted]

NOTES: Bold numbers in the table above represent scenarios where the switchgrass project could be commercially competitive. "SO_2" refers to SO_2 emissions credits valued at $150/ton. "PTC" refers to the section 45 production tax credit for wind and closed-loop biomass, valued at 1.8 ¢/kWh. "GPI" refers to green power incentives, and 25% GPI, 50% GPI, and 100% GPI refer to Alliant's Second Nature green power offerings that allow customers to buy electricity with a 25%, 50%, or 100% mix of renewable power, respectively. The overall premiums for the 25%, 50%, and 100% GPI scenarios are: 0.5 ¢/kWh, 1.0 ¢/kWh, and 2.0 ¢/kWh, respectively.

4.3 Conclusions

The commercial success of this project is predicated on the Prairie Land farmers' ability to provide an economically priced fuel and Alliant Energy's ability to generate cofired power at a competitive cost of electricity. These are influenced by the impact of the project on existing ash management practices at OGS, the availability of regulatory and other financial incentives, and the competing generation options in Iowa. The low, med-low, med-high, and high delivered switchgrass costs considered in Exhibits 4-6 and 4-7 are discussed in Chapter 3.0 (see Exhibit 3-3 and section 3.2). The conclusions in this report only reflect consideration of these four delivered switchgrass costs. It is important to note that these costs were chosen based on available data and are used as guidelines, but farmers may be able to provide switchgrass at other prices (see Appendices I and J for information on other possible delivered costs). This section discusses the project's competitiveness without and with a green power premium (exhibits 4-6 and 4-7, respectively) and then outlines the conditions necessary for commercial success.

Exhibit 4-6: Conditions Where Cofiring will be Competitive with Coal, Wind-Low, or Wind-High, at Various Delivered Switchgrass Costs *

Regulatory Incentive	Ash Management Scenario	Switchgrass Delivery Cost Scenario			
		Low ($40/ton)	Low-Med ($52/ton)	Med-High ($68/ton)	High ($92/ton)
w/SO_2 alone	Base Case—no change	Wind-A	Wind-H	---	---
	Lost Ash Market	---	---	---	---
w/SO_2 + PTC	Base Case—no change	Wind-L	Wind-A	Wind-A	---
	Lost Ash Market	Wind-A	Wind-H	---	---

* As explained in Chapter 3.0, the switchgrass COE is compared to the coal and wind COEs; "Wind-L" means that this option is competitive with wind-low, wind-ave, and wind-high; "Wind-A" means that this option is competitive with wind-ave and wind-high; "Wind-H" means that this option is competitive with wind-high only.

The busbar COE for coal at OGS is 1.5 ¢/kWh, the wind-low COE is 2.9 ¢/kWh, the wind-ave COE is 3.9 ¢/kWh, and the wind-high COE is 4.9 ¢/kWh. In the absence of a renewables mandate, the switchgrass COE would have to be less than 1.5 ¢/kWh to compete with coal. If Iowa increases its renewables mandate in the future, the switchgrass COE could be as high as 4.9 ¢/kWh and still be competitive with wind. Exhibit 4-6 illustrates when the switchgrass COE is competitive with coal, wind-low, wind-ave, and wind-high at these delivered cost options:

- At the "low" delivered cost of $40/ton, the project:
  - is competitive with <u>wind-low</u> in the base case if the project gets both regulatory incentives
  - is competitive with <u>wind-ave</u> in the base case, with one or both regulatory incentives; is competitive with <u>wind-ave</u> if it results in lost ash markets, but receives both regulatory incentives
  - is competitive with <u>wind-high</u> in the base case, with one or both regulatory incentives; is competitive with <u>wind-high</u> if it results in lost ash markets, but only if it gets both regulatory incentives
  - is not competitive with coal under any combination of scenarios and regulatory incentives outlined in Exhibit 4-6[32]

- At the "med-low" delivered costs of $52/ton, the project:
  - is competitive with <u>wind-low</u> in the base case if the project gets both regulatory incentives
  - is competitive with <u>wind-ave</u> in the base case if it receives both regulatory incentives
  - is competitive with <u>wind-high</u> in the base case, with one or both regulatory incentives; is competitive with <u>wind-high</u> if it loses the ash market, but only if it gets both regulatory incentives
  - is not competitive with coal under any combination of scenarios and regulatory incentives outlined in this analysis[32]

[32] Other alternatives, such as systems benefits charges, for making the project commercially viable in competition with coal and in the absence of green power premiums are discussed in chapter 5. As shown in Exhibit 4-7, if a green power incentive of 0.5 ¢/kWh or more is obtained, the CVBP can compete with coal in several of the scenarios considered.

- At the "med-high" delivered cost of $68/ton, the project:
  - is only competitive with <u>wind-ave</u> and <u>wind-high</u> in the base case (where the ash market is maintained) and if the project gets both the SO_2 credit and the PTC
  - is not competitive with coal or wind-low under any combination of scenarios and regulatory incentives considered in Exhibit 4-6

- At the "high" delivered cost of $92/ton, the project:
  - is not competitive with coal or any of the wind options under any combination of scenarios and regulatory incentives considered in Exhibit 4-6

Exhibit 4-7: Conditions Where Cofiring will be Competitive with Coal or Wind, with Regulatory and Financial Incentives*

Regulatory/Financial Incentive Combination	Scenario	$40/ton (Low)	$52/ton (Low-Med)	$68/ton (Med-High)	$92/ton (High)
SO_2 alone (no GPI)	Base Case	Wind-A	Wind-H	---	---
	Lost Ash Market	---	---	---	---
SO_2 + 25% GPI	Base Case	Wind-A	Wind-H	---	---
	Lost Ash Market	---	---	---	---
SO_2 + 50% GPI	Base Case	Wind-A	Wind-H	---	---
	Lost Ash Market	--	---	---	---
SO_2 + 100% GPI	Base Case	Wind-A	Wind-H	---	---
	Lost Ash Market	---	---	---	---
SO_2 + PTC (no GPI)	Base Case	Wind-L	Wind-A	Wind-A	---
	Lost Ash Market	Wind-A	Wind-H	---	---
SO_2 + PTC + 25% GPI	Base Case	**Coal**	Wind-A	Wind-A	---
	Lost Ash Market	Wind-A	Wind-H	---	---
SO_2 + PTC + 50% GPI	Base Case	**Coal**	Wind-A	Wind-A	---
	Lost Ash Market	Wind-A	Wind-H	---	---
SO_2 + PTC + 100% GPI	Base Case	**Coal**	**Coal**	Wind-A	---
	Lost Ash Market	**Coal**	Wind-H	---	---

* As explained in Chapter 3.0, the switchgrass COE is compared to the coal and wind COEs; "Coal" means that this option is competitive with coal, wind-low, and wind-high; "Wind-L" means that this option is competitive with wind-low and wind-high; "Wind-H" means that this option is competitive with wind-high only.

The presence of the green power premium improves the project's competitive position compared to coal. The wind values shown in this table are from Exhibit 4-6 and the graphs provided in the Appendix; they are included here to provide a comprehensive overview of the project's commercial viability. Exhibit 4-7 assumes that wind and biomass power receive the same green power incentive; therefore, neither generation option gains an advantage over the other due to green power incentives. Conclusions relative to competition with wind are stated above in the discussion following Exhibit 4-6. The following results apply to the project's competition with coal:

- At the "low" delivered cost of $40/ton, the project:
  - is competitive with <u>coal</u> if its gets both regulatory incentives, retains the ash market, and sells 25%, 50%, or 100% of its green power at a premium of 2 ¢/kWh (or, alternatively, if it sells all of its biopower at 0.5, 1.0, or 2.0 ¢/kWh premiums,

respectively); is also competitive with coal if it loses the ash market, but only in the case where it gets both regulatory incentives and can sell 100% of its green power

- At the "med-low" delivered cost of $52/ton, the project:
  - is only competitive with coal in the base case if the project gets both regulatory incentives and can sell 100% of its green power
- At the "med-high" and "high" delivered costs of $68/ton and $92/ton, the project:
  - is not competitive with coal under any combination of scenarios and regulatory incentives detailed

4.3.1 Conditions for Commercial Success

This report demonstrated how various elements such as regulatory incentives and impact on existing ash market can affect project success. Specific elements necessary for the project to be commercially viable compared to existing coal power at OGS, wind-low, wind-ave, and wind-high are outlined below.

General Observations

- The best case is if all the financial incentives are available, the ash market is retained, and the delivered costs are low
- The green power premium significantly improves the project's competitiveness compared to coal
- Given these delivered costs, a greater demand for renewable power, either through expansion of Iowa's renewables mandate or expansion of Alliant's green power program, will significantly help project viability
- The delivered cost drives the project's competitiveness; this cost can be lowered by achieving higher switchgrass yields, lower production costs, lower storage costs, and by using lands that qualify for benefits under the CRP biomass pilot program (the value of the CRP biomass pilot program would be about 60 to 80% of the value of provided by the PTC)
- The PTC significantly improves the project's competitiveness
- The SO_2 credit alone is not a major factor in the project's economics

To be competitive with COAL:

- *Without a green power premium:*

  - The delivered price of switchgrass can be up to $35/ton, if the project retains the ash market and gets both the SO_2 and the PTC

- *With a green power premium,*

  and 100% sales at 2 ¢/kWh:

  - The delivered price of switchgrass can be up to $62/ton, if the project retains the ash market and gets both the SO_2 and the PTC
  - The 100% green power premium allows the farmer to deliver the switchgrass at a cost that is about $28/ton higher than the delivered cost without the premium

  and 50% sales at 2 ¢/kWh (or 100% sales at 1.0 ¢/kWh):

– The delivered price of switchgrass can be up to \$49/ton, if the project retains the ash market and gets both the SO_2 and the PTC

and 25% sales at 2 ¢/kWh (or 100% sales at 0.5 ¢/kWh):

– The delivered price of switchgrass can be up to \$42/ton, if the project retains the ash market and gets both the SO_2 and the PTC

To be competitive with WIND-LOW:

- The delivered price of switchgrass can be up to \$54/ton, if the project retains the ash market and gets both regulatory incentives

To be competitive with WIND-AVE: [33]

- The delivered price of switchgrass can be up to \$68/ton, if the project retains the ash market and gets both regulatory incentives
- The delivered price of switchgrass can be up to \$[redacted]/ton, if the project retains the ash market and only gets the SO_2 credit

To be competitive with WIND-HIGH:

- The delivered price of switchgrass can be up to \$82/ton, if the project retains the ash market and gets both regulatory incentives
- The delivered price of switchgrass can be up to \$[redacted]/ton, if the project retains the ash market and only gets the SO_2 credit

[33] This case most represents the intended target competition for the project.

5.0 NEXT STEPS

The analysis conducted for this report highlights the importance of policy or market development efforts to the project's commercial viability. These include: emissions credits, green power markets, and state/federal regulatory and financial incentives. ***In general, if one or two presently unavailable but feasibly obtainable incentives or policies materialize—such as the production tax credit, green power premiums, or increased renewables mandates or market demand in Iowa--the project can achieve commercial success.*** This chapter begins by outlining the relevant elements of Iowa's *2002 Comprehensive Energy Plan Update* and recommendations made by Iowa's State Energy Task Force in its 2001 report to the Governor. It then discusses various options that could be pursued by project partners (or that could occur without partner actions) to bring increased revenue or value to the project. With the exception of CO_2 trading, which is still in the infancy stage, these items could be viable both in the near and long term.

5.1 2002 Comprehensive Energy Plan Update

"I firmly believe that energy efficiency and renewable energy hold solutions for Iowa to take a proactive stance toward greater energy independence and firmer economic opportunities."

\- Thomas J. Vilsack, Governor of Iowa

"Central to the plan was a commitment to improve energy efficiency and expand renewable energy production and use in Iowa. The state reaffirms its dedication to meeting the goals set forth in that plan."

\- Jeffrey R. Vonk, Director, Iowa Dept. of Natural Resources

These two statements from Iowa's *2002 Comprehensive Energy Plan Update* highlight the importance of renewable energy and energy efficiency to the state's goals of energy independence and security, economic development, and environmental protection. The Plan outlines many instances where renewable energy, including biopower (and switchgrass in particular), can play a pivotal role. Since it is already underway, the CVBP project is well positioned to benefit from these policies and contribute to the state's goals. For example, the Plan specifically mentions switchgrass as a potential biomass fuel source four times and it discusses the October 2000 cofiring test as a successful application of renewable energy.

Overall, the Plan authors recognize the importance of legislative action to the renewable energy industry. They mention that Iowa is a leader in renewable energy because it has a history of policies/legislation that establish requirements or provide financial incentives for in-state energy production.[34] The Plan says that the state's natural resources and agricultural expertise make it the ideal locale for the development of "homegrown" energy. However, despite its growth in renewable energy capacity, they say that state government incentives such as legislative/financial assistance, portfolio standards, and a credit-trading program are still needed for renewable energy to compete with fossil-fueled power. The Plan's policy recommendations relevant to biopower and this project include the following:

<u>Establish a Statewide Public Benefits Fund</u>

The objective of the Public Benefits Fund is, by 2010, to reduce electric and natural gas consumption in Iowa by 20% and increase the amount of electric energy produced from

[34] The 1990 Iowa Comprehensive Energy Plan and each subsequent biennial plan called for the state to increase renewable energy generation in the state to 10%.

renewable energy resources in Iowa by 10%. Implementation of the Fund should include these conditions:

- Funding should be collected through a charge on all electric, natural gas, fuel oil and propane-consuming customers in the state, based on usage. (Currently, 19 states apply broad-based charges to provide for renewable energy, energy efficiency, and low-income programs.)
- Based on a needs assessment and a strategic plan outlining goals and opportunities, funding will be used to establish a menu of rebates, loans, incentives, credits, grants, education and other mechanisms that will make programs and projects achievable. Funding will also be used for research and demonstration of energy efficiency and renewable energy technologies.

<u>Ensure State Government Leads By Example</u>
At least 10% of the electricity purchased by state government should be generated from renewable energy resources, by 2005. This requirement can be met by facilities installing renewable energy production capabilities, such as wind turbines, photovoltaics or biomass systems. It also could be purchased from utilities offering renewable energy purchasing options.

<u>Develop an Emissions Credit Trading Program</u>
The state of Iowa should establish a credit-trading program for emissions avoided at state government facilities through energy efficiency and renewable energy initiatives. The program will include development of quantification procedures, a monitoring and verification process, a marketing plan and a pilot project. The program will include credit trading for criteria pollutants (as established by federal Clean Air Act) and carbon.

5.1.1 Governor's Energy Policy Task Force

The Task Force spent a year studying Iowa's energy needs and outlined its recommendations in a report released in October 2001. These policy suggestions helped form the *2002 Iowa Comprehensive Energy Plan Update*. Relevant items are listed below; nearly all were directly employed in the 2002 Plan.

- Goals and policy recommendations included "ensuring Iowa is maximizing energy efficiency and production of renewable energy" and "diversifying the supply of energy sources to include renewable energy"
- Since Iowa is an agricultural state, expanding the use of switchgrass and crop residues for electric generation is possible
- It sets forth a goal of 1,000 MW of renewable energy by 2010 [this could equate to the Plan's 10% goal][35], to be accomplished through vigorous subsidies and incentives, a proactive effort to provide appropriate transmission systems, and by eliminating regulatory barriers to increased use of renewable sources
    - a major barrier to achieving this goal is the absence of transmission from areas where renewable power could be produced [this would not pose difficulties for the CVBP since OGS already has transmission capability]
- State government's role:

[35] Present generation capacity in Iowa is around 9,003 MW and is expected to grow significantly by 2010.

- encourage the increased use of commercialized renewable energy technologies and support R&D of emerging technologies involving Iowa-grown agricultural commodities
- purchase renewables-based electricity to the extent possible
- be an equity investor for the amount needed to help coal-fired power plants use some biomass or municipal wastes as fuel
- either own or have significant equity investment in a base-load power plant
    - currently, approximately 23 cents of every dollar paid by an investor-owned utility customer goes to pay taxes and shareholder return; this money does not have to be paid by a state-owned company, so it can be invested in public purpose programs

5.2 CO_2 Trading

Carbon trading is a relatively new concept but it is gaining attention as a policy tool. However, absent a global mandatory emissions reduction requirement, several companies, non-profit groups and governments have decided to undertake greenhouse gas (GHG) emissions trading. This market has emerged due to international treaty negotiations, anticipation of future regulations, and corporate foresight. Approximately 65 greenhouse gas trades for quantities above 1,000 tonnes of carbon dioxide-equivalent (CO_2e) have occurred in the world since 1996. (Pew Center, 2002) This market has emerged due to international treaty negotiations, anticipation of future regulations, and corporate foresight.

This project may benefit from two CO_2 trading efforts, one is through the Iowa state government and the other is with a regional trading exchange. Iowa's *2002 Energy Plan Update* recommends that the state establish a credit-trading program for emissions avoided at state government facilities. It applies to reducing criteria pollutant and carbon emissions through energy efficiency and renewable energy initiatives.

The second option offers a more near-term CO_2 trading opportunity for the CVBP project. The Chicago Climate Exchange was established in 2001 as a regional GHG trading exchange. Participating companies would commit to voluntarily reducing their GHG emissions by 2% below 1999 levels during 2002 and 1% annually thereafter (Pew Center, 2002). The Exchange is expected to be up and running by the third quarter of 2002 for participants in seven states: Illinois, Indiana, Iowa, Michigan, Minnesota, Ohio, and Wisconsin. Based on data from average CO_{2e} trades, the CVRCD project can see a benefit between 0.06 ¢/kWh and 0.36 ¢/kWh if it engages in CO_2 trading.[36] Based on this range of CO_2 values, participating in this program could provide an additional $165,000 to $991,000 of revenue for the project per year. CVBP project participants will need to assess whether the CO_{2e} emissions reductions from biomass cofiring make it worthwhile to be involved in the exchange.

5.3 Green Power Markets

The state of Iowa has instituted a mandatory utility green power option that requires all utilities in the state to offer green power to their customers beginning January 2004. Currently, Iowa is the only state with a final green power standard that includes biomass cofiring as an approved

[36] These values are based on the assumption that 1,000 tons of switchgrass yields 1,423 tonnes of CO_2. Amos, W., 2002) Assuming OGS consumes 200,000 tons of switchgrass annually, the benefit equates to 0.06 ¢/kWh at a CO_2 credit value of $0.60/tonne and to 0.36 ¢/kWh at a CO_2 credit value of $3.50/tonne. (Pew Center, 2002)

technology for certified green power products using the *Green-e* label.[37] Alliant Energy has already begun offering a green power option to its residential customers. Its Second Nature program levies an additional 0.5, 1.0, or 2.0 ¢/kWh premium, based on three participation levels of 25%, 50%, or 100% green power, respectively. Section 4.1.3 discusses this program and how this project might be incorporated.

If all of the project's power could be sold at a 2.0 ¢/kWh premium, the increased revenue to the project from green power sales would be about $5.5 million per year. At a 1.0 ¢/kWh premium, revenue would increase by $2.75 million per year, and the increased revenue would be about $1.375 million per year if all of the project's power was sold at a green premium of 0.5 ¢/kWh. Project partners would need to sign up about 30,000 average Iowa residential customers to sell all of the biopower generated by the CVBP. This means that nearly 8% of Alliant's total Iowa residential customer base, or about 4% of its total residential customer base (in Iowa, Wisconsin, Minnesota, and Illinois), would need to purchase green power from the project. By comparison, the customer participation rates for the top ten utility green pricing programs range from 3% to 7%, with a premium ranging from 1.0 to 1.5 ¢/kWh. (USDOE, 2002)

Since the residential sector alone may not be a large enough green power market to significantly impact the Chariton Valley Biomass Project, project partners would most likely have to expand their green power marketing efforts to include corporate and government customers. Compared to the residential sector, these two consumer groups have an institutional interest in purchasing green power, have greater financial means to do so, are more aware of alternative technologies, and they can buy it in larger volume.

Corporations' incentives to buy green power are to save money and/or to adhere to corporate social responsibility (CSR). CSR is a growing management trend where companies voluntarily align their normal business practices to address environmental and social issues. The companies hope to benefit from positive public relations (PR) publicity and improved customer relations. One of the more popular CSR efforts in the U.S. has been the use of renewable energy and energy efficiency. Companies such as Dupont, Kinko's, and Cargill Dow have installed renewable energy systems at their facilities or purchased green power in an effort to reduce their environmental footprint. By recognizing this management trend, project partners can target part of their marketing efforts to companies in Alliant's service area with the CSR approach.

Government agencies can fulfill executive directives and set an example. As stated in the state's *2002 Energy Plan Update*, at least 10% of the electricity purchased by Iowa's state government should be generated from renewable energy resources, by 2005. One suggestion for meeting this requirement is to purchase from utilities offering renewable energy purchasing options. To provide some perspective, in 2001 it is estimated that Iowa state government facilities consumed 561,320,413 kWh of electricity, so 10% would be 56,132,041 kWh/yr. (Iowa Dept. of Natural Resources, 2002). If the CVBP is expected to generate 275,360,000 kWh/yr, then at the 10% rate, Iowa state government can purchase approximately 20% of the project's output.

Federal agencies can also make a large contribution. Energy Secretary Abraham recently challenged DOE operations to buy renewable energy to supply 5% of the agency's total annual energy needs by the year 2005. In April 2002, DOE announced that it would purchase green power to supply 17% of the electricity needs at its headquarters facilities in Washington, DC and Germantown, MD. (NREL, 2002)

[37] New York and Florida have draft/proposed standards that include cofiring.

In addition, Executive Order 13123 directs the Federal government to reduce square foot energy consumption in federal buildings by 30% in 2005 and 35% in 2010, relative to the 1985 baseline. It also requires federal facilities to derive 2.5% of their annual electricity consumption from renewables. This is equivalent to 1,422 GWh/yr. Renewable power purchases count toward both the renewables increase goal and the square foot energy reduction goal. According to the Federal Energy Management Program, the Federal government has met approximately 28% of the 2.5% renewables goal established in EO13123. Of the 397 GWh of renewable power presently used by the Federal government a year, 49% (~32 MW) is from green power purchases and 23% is from biomass power (~15 MW).[38] The remaining 1,023 GWh/yr of targeted renewables purchases are about 3.7 times the total amount of power generated by the Chariton Valley Biomass Project.

While it is not likely that the project could sell all of its power to one buyer, it may be possible to sell a significant fraction of the project's power to the Federal or state governments or other large consumers. By considering all potential green power buyers, including residential, governmental, and commercial customers, project partners may be able to sell enough of the project's power into the green power market to make a significant difference toward making the project commercially viable.

5.4 State/Federal Incentives

Three major government initiatives could be very important to the commercial success of this project: Iowa's Alternative Energy Law, the Federal Production Tax Credit (PTC), and the Federal Conservation Reserve Program (CRP). The Alternative Energy Law is a renewables mandate, which stimulated a demand for green power in the state. The two federal incentives lower the project's cost of electricity. In the case of the CRP pilot program, the government actually saves money by supporting this project.

<u>Iowa's Alternative Energy Law/Renewables Goal/SBC</u>

Under Iowa's Alternative Energy Law, the state's three investor-owned utilities were required to purchase a total of 105 MW of renewable power; these utilities have already met this requirement. In its 2001 report, the state's Energy Task Force recommended reaching a total of 1,000 MW of renewables capacity by 2010; this is comparable to the Energy Plan's recommended 10% renewables goal. As mentioned in section 5.1, to pay for this increased capacity, the Plan suggests establishing a systems benefit charge (SBC) that will be levied on all electric, natural gas, fuel oil, and propane-consuming customers in the state. The table below shows that, by 2001, Iowa had 608 MW of installed renewable power capacity, most of it wind power installed since 1998. This would leave 392 MW to be installed to meet the 1,000 MW goal.

Past legislation tried to promote renewable energy generation from small independent companies and groups, but the reality was that this incentive was largely ineffective because large non-Iowa companies own most facilities producing the 105 MW. (Governor's Energy Policy Task Force, 2001) Thus, the Task Force called for future legislation to eliminate restrictions on Iowa companies owning renewable generation facilities. These policy recommendations are intended to increase the demand for renewable energy and will give the CVBP an even greater chance to remain commercially viable.

[38] Federal Energy Management Program, 2002.

Installed Renewable Power Capacity in Iowa

Renewable Source	Installed Capacity (MW)	Fraction of Total
Wind	335.4	55%
Solar	<< 1	0%
Biomass	138.7	23%
Hydro	134.3	22%
Total	**608.4**	100%
2010 Iowa Goal	*1,000.0*	
Required New Renewables in Iowa to Meet 2010 Goal	**391.6**	

Source: *2002 Comprehensive Energy Plan Update*

An analysis was conducted to estimate the potential per kilowatt-hour systems benefit charge required to make the CVBP commercially viable. The analysis, provided in Appendix G, estimates that the average Iowa electric bill "mark-up" needed to fully pay for this project, with no other incentives except the existing SO_2 credits, would be only 0.0211 ¢/kWh (at an average delivered switchgrass cost of $52/ton). This equates to an average additional cost of $6.59/yr (or $0.55/month) for each residential electric customer in the state. The analysis in Appendix G compares this amount to rate riders used in Iowa to pay for existing energy efficiency programs and alternate energy production. This comparison indicates that the amount required for the CVBP (if no new incentives become available) is only 6.4% of the existing Energy Efficiency Cost Recovery Rider or 16.1% of the existing Alternate Energy Production Clause Rider.

Section 45 Production Tax Credit (PTC)

The PTC was shown to be a key component of the project's economics, but as currently written, the parameters are too restrictive for most biomass projects; in fact, very few biomass projects have qualified for this incentive over its 10-year existence. Conversely, wind power developers have already been allocated an estimated $1.14 billion from this credit (this estimate very conservatively neglects any qualifying wind projects after the year 2001).[39] If this 1.8 ¢/kWh credit becomes available to the CVBP, it could be worth about $4.96 million per year.[40] Over the course of the 10-year life of the credit for the CVBP, the cumulative value of this credit to the CVBP would be less than 4% of that already obligated to wind projects (neglecting all costs from post-2001 wind installations). If the 400 to 450 MW of U.S. wind installations in 2002, and the projected installations of over 2,000 MW in 2003 are considered (AWEA, 2002), the fraction of this credit obligated to the Chariton Valley Biomass Project would be significantly less than 4%.

[39] This assumes that all 95.5 billion kWh of wind capacity installed in the U.S. between 1992 and 2000 receives this credit for 10 years; the credit was adjusted for inflation. See Appendix H for details on the analysis.

[40] This assumes that the entire 275,000,000 kWh of biopower produced annually receives this credit for 10 years; the credit was not adjusted for inflation.

Conservation Reserve Program (CRP) Biomass Pilot Project

The CRP program turns out to be beneficial to both the farmers and the federal government. The farmers receive a rental payment for planting switchgrass on CRP land, which helps them reduce their delivered cost of fuel and increases their competitiveness. The government ends up saving money because it pays 10% less per acre to these farmers compared to the amount it pays farmers to keep CRP land fallow. If 50,000 acres are harvested for switchgrass production, the federal government will *save* $465,000 a year through this project.[41] The Chariton Valley Biomass Project has already qualified for this pilot program. This USDA program could help farmers reduce the delivered cost of their switchgrass fuel grown on CRP lands by $14 to $21 per ton compared to switchgrass grown on non-CRP lands.

5.5 Switchgrass Production

In addition to seeking external incentives to bring additional revenue to the project, project partners will need to seek ways of reducing delivered costs of switchgrass. Lowering switchgrass production costs and maximizing external revenue sources will be the best ways to ensure commercial viability of this project. Several fuel delivery cost scenarios were discussed in section 3.2. Delivered costs in the scenarios discussed ranged from $40/ton to $92/ton. Except for the "low" delivered cost scenario of $40/ton, all estimates were based on research and estimates provided by Iowa State University. The $40/ton "low" scenario was based on the low end of recent hay market auction prices in Iowa for "fair" quality hay, and on estimates reported for Iowa by Oak Ridge National Laboratory. If the farmers can deliver switchgrass to OGS at costs in the $40 to $60 per ton range, many of the scenarios considered in this analysis would allow the project to be commercially viable. The closer farmers can get to producing and delivering switchgrass at costs near the lower end of this range, the higher the likelihood of commercial viability of the project. At delivered costs near the low end of this range, nearly all scenarios considered could be commercially viable if the existing ash market at OGS is not negatively impacted by the biomass project. Aside from the assistance provided by the CRP Biomass Pilot Project, there are several routes farmers can pursue to reduce production costs. These include: 1) Reducing storage costs, 2) Improving yields above 6 ton/acre, 3) using cool season grasses, 4) harvesting improvements, and 5) economies through learning. Efforts are under way in all of these areas.

[41] This assumes a $93/acre CRP rental payment multiplied by 10%, applied to 50,000 acres.

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APPENDIX A

Draft Chariton Valley Biomass Supply Contract

BIOMASS SUPPLY AGREEMENT
BETWEEN
______________________ (SELLER)
AND
ALLIANT ENERGY CORPORATE SERVICES, INC., AGENT FOR IES UTILITIES, INC.(BUYER)

1. GENERAL TERMS

These terms and conditions constitute the requirements made for delivery of biomass to Ottumwa Generating Station.

This Agreement is effective this ____ day of 200x by and between _____________ ("Seller") and Alliant Energy Corporate Services, Inc., agent for IES Utilities Inc. ("IES"), ("Buyer").

The quantity of biomass shall be ____________tons per year according to dates specified.

Seller agrees to sell and deliver and Buyer agrees to buy and accept biomass of the quantity and quality, at the price and on the terms and conditions stated in this Agreement.

The decision to make any modifications to the Generating Station facilities or operations will be solely in the discretion of the Buyer. Similarly, the decision to make any modifications in production and loading operations will be solely in the discretion of the Seller.

2. QUALITY ASSURANCE OF BIOMASS

The biomass shall be substantially free of magnetic material and other foreign material impurities. It is presupposed that the biomass does not contain any large foreign bodies and that no ammonia or other chemicals have been added after the bales have been pressed.

If the biomass in any shipment violates any of the rejection limits specified in section 3.6, Buyer may in its sole discretion reject such shipment. In that event, Buyer shall have no obligation to pay for the rejected biomass and Seller shall be responsible for all costs incurred by Buyer with respect to the rejected biomass and further shall be responsible for the environmentally sound disposal of the rejected biomass.

If the biomass fails to meet the rejection limits specified in the Independent Contractor Agreement for two shipments within a 30 day period criteria specified in the Independent Contractor Agreement, the Buyer may suspend all further shipments until Seller can demonstrate to Buyer's satisfaction that biomass quality will meet the applicable specifications.

3. TERMS OF DELIVERY

3.1 Point of Delivery

The delivery point will be F.O.B. at the biomass processing facility.

Title and risk of loss shall pass to the Buyer at the delivery point.

Seller's transport shall be compatible with Buyer's road, storage and unloading facilities.

Seller shall load each trailer at Seller's expense.

Seller shall be responsible for demurrage and all other charges invoiced to Seller by Seller's carrier resulting from Seller's failure to load, unload or otherwise delay carriers transport.

3.2 Transport of Biomass

When unloading at the biomass storage of the power plant, the supplier is registered in a data terminal by means of an ID card. The biomass storage is supplied with two unloading cranes and the unloading is carried out by the power plant.

Before leaving the storage building, the driver will get a receipt for the load according to agreement. The following information will be given on the receipt:

- Weight of the biomass in pounds;
- Moisture content of the biomass in percentage;
- Supplier;
- Date and time;
- Consecutive numbering.

3.3 Size of the Biomass Bales

The biomass bales are to be delivered as big-bales with the following approximate dimensions and weight:

Width:	~48 inches	Length	~96 inches
Depth:	~36 inches	Weight	~1100 lbs

In years with extreme weather conditions, it may be accepted that a few bales in each load have a minimum weight of as little as XXX lbs/bale.

3.4 Moisture Content of the Biomass Bales

The straw bales should have as low a moisture content as possible. The moisture content is measured during weighing by the measuring equipment installed in the cranes. Each measurement is made as an average across two bales. At each straw gripping device the moisture content is measured from several representative places. The average moisture content of two straw bales is not to exceed 20%. Not even one measurement of a moisture content of 23%

or above made in the straw gripping device will be accepted, and the layer of straw bales or the load, respectively, will be refused.

Test measurements can be made by inserting the moisture-measuring spear into the straw bales at a place chosen by the controller. Measurements are not to be made in the outermost 5 cm (2 inch) of the straw bale. If the moisture content of two manual test measurements made at an interval of 30 cm (12 inch) exceeds 30%, the layer of straw bales or load, respectively, will be refused at the reception area.

The moisture content of a load of straw for settlement is registered during the receipt by means of a microwave system. A moisture content below 10% cannot be registered. If the microwave system breaks down, the power plant personnel will measure the moisture content by inserting moisture-measuring spears at 10 different locations in each load. The average of these 10 measurements will be valid. The result of the manual measurement is registered in the power plant's registration system and settlement will take place as usual.

3.5 Loading of the Biomass Bales

Each transport is to carry XX biomass bales loaded as follows:

- closely packed;
- longitudinally on the flatbed trailer;
- along the longitudinal centerline of the trailer;
- close towards the front of the truck;
- maximum of three bales high (so that the XX" dimension is in the vertical);
- in such a way that the bales are not staggered;
- the biomass bales are to be standing on the twines

3.6 Rejection Criteria

The biomass transport may be rejected if:

- the biomass bales deviate from the criteria for size (see section 3.3);
- the moisture content of the biomass bales is too high (see section 3.4);
- the biomass bales are not loaded correctly (see section 3.5);
- the biomass bales contain substantial non-combustible material;
- all twines around the bales are broken;
- the biomass bales on visual inspection deviate from a normally satisfactory quality, e.g. due to decomposition.

If the biomass transport is rejected, information will be given about which bales caused the rejection.

If a seller considers a rejection to be unacceptable, the seller can demand additional inspection supervised by the buyer and the seller. A report will be prepared in case of rejection.

If a layer of biomass is rejected, the seller is to bear all expenses connected with cleanup and disposal of the load. If the biomass bales have been unloaded, the power plant is responsible for cleanup, etc.

If biomass loads are repeatedly rejected on the above grounds, this is considered a breach of contract and entitles the buyer to suspend the agreement and to purchase a replacement supply on the supplier's account.

3.7 Vehicles

Transport of biomass by tractor is not permitted unless otherwise agreed.

The fully loaded flatbed trucks are not to exceed the following dimensions:

Length by unloading:	53 feet
Width:	10 feet
Height:	14 feet

Unloading of the flatbed trucks must be possible from any of the sides and from the back. (e.g. the flatbed truck must not have a rear-mounted crane on the trailer).

After unloading, all flatbed trucks are to be cleaned by their drivers before leaving the unloading area. A vacuum cleaner is available for this purpose. Any littering of the area and road is to be avoided.

Any possible environmental requirements in connection with the transport are the responsibility of the carrier.

3.8 Tonnage Guarantee:

The total amount of bales stored, ready for processing, at the Buyer's facility will be xxxx bales.

The minimum amount of bales stored, ready for processing, at the Buyer's facility will be xxx bales.

If Buyer's facility is shut down for scheduled maintenance, schedule testing or for other scheduled reasons, Seller will be informed at least one (1) week prior to shutdown and delivery of biomass will discontinue when total amount of allowable site stored bales is reached.

If buyer's facility experiences an unscheduled shut down, Seller will be promptly notified and Seller will discontinue delivery of biomass bales when the total amount of allowable site stored bales is reached.

If the Buyer or the Seller request the biomass storage area to be emptied or partially emptied of biomass, the Buyer and Seller will negotiate the timing and duration of the interruption.

3.9 Opening Hours

The power plant will be open for receipt of biomass bales on all normal workdays between 7 a.m. and 6 p.m. as well as on Saturdays between 7 a.m. and 2 p.m. Receipt of biomass bales outside these hours may only take place according to special agreement.

The flatbed trucks are not to arrive at the gate of the power plant before 7 a.m. and are to be out of the gate at the latest at 6 p.m. on workdays and at 2 p.m. on Saturdays.

If the unloading system of the power plant is out of operation, the waiting time can be settled at $x.xx/hour pro rata according to agreement with the buyer of the power plant. As is the case for the basis price of biomass, the rate for waiting time is adjusted once a year on August 1.

3.10 Miscellaneous

All drivers must be familiar with the safety regulations of the power plant, which can be requisitioned at the plant.

Directions given by the power plant personnel must be complied with.

4. DELIVERY SCHEDULES

Delivery takes place according to agreement with the logistics officer of the power plant during the period specified in the corresponding contract.

In July/August the power plant issues a draft delivery schedule. The draft specifies the supplier's delivery period. The supplier's wishes can to some extent be considered during the planning phase.

At the latest two workdays before delivery of biomass is to be commenced, the supplier will be contacted by the logistics officer of the plant with a view to further details of the time and amount of delivery per day.

In case of suspension of or reduction in the biomass delivery or supply, the other party is to be informed of this immediately as well as of the reason for and the expected duration of the suspension or reduction.

If transport of a load has been commenced, the load is considered as delivered, and the power plant must accept the load (unless the load is rejected in accordance with section 3.6).

Force Majeure

The parties are not liable if force majeure occurs after the agreement has been made.

By force majeure is to be understood - according to this contract – any circumstances beyond the control of the parties including unusual natural phenomena (Acts of God), fire in biomass storages, faults in or breakdown of the boiler of the power plant including reception system, which renders impossible the receipt and combustion of biomass.

In case of force majeure each of the parties are exempted in whole or in part from their obligation to deliver or purchase.

The party wishing to claim force majeure is to inform the other party in writing and without undue delay of the accrual of the force majeure and the expected cessation of the force majeure.

The reason for the force majeure is to be documented in writing.

Notwithstanding the foregoing, it is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the labor difficulty and that the above requirement of due diligence to resolve the force majeure shall not require the settlement of strikes or lockouts when such a course is inadvisable in the discretion of the party having the labor difficulty.

5. PRICING AND TERMS OF PAYMENT

5.1 Pricing

The biomass is settled based on the contract basis price.

The Price(s) of the biomass[s] for XXXX shall be $____ per net ton F.O.B. at the process facility.

This [These] Price[s] is [are] firm for the term of this Agreement subject only to adjustments for changes in laws and regulations enacted and in force during the term of this Agreement.

The basis price is adjusted once a year on August 1.

As specified in the contract, the basis price is adjusted during the delivery season by means of season variation and weight correction as follows:

Seasonal Variation

In the period August 1 to August 31 the delivery price is equal to the basis price. For delivery in the subsequent months, the price is increased by a monthly addition. The monthly addition is calculated each month of the delivery year based on the following equation:

$$(\textit{Basis price}) \text{ x } \frac{\textit{delivery month} - \boldsymbol{1}}{12} \text{ x } (\textit{discount rate} + \mathbf{10})\ \%$$

The addition is calculated to the nearest cent. The monthly additions in the delivery year are calculated at the start of the delivery season on basis of the average discount rate + 5% during the preceding period from April 1 to March 31.

Weight Correction

The weight registered during the weighing is adjusted for moisture as follows:

The basis price applies to XX% moisture content. XX% moisture content covers the range from -.5 to +.4%. XX% moisture content covers the range from -.5 to +.4%, etc.

If the average moisture content is less than XX%, the weight is corrected by 2% for each 1% reduced moisture content. Moisture content below 10% cannot be measured. If the moisture content is more than XX% the weight is corrected by -2% for each 1% increased moisture content.

Example: Moisture content XX%: the weight is increased by XX%.
Example: Moisture content XX%: the weight is reduced by XX%.

5.2 Terms of Payment

The power plant specifies a statement of delivered straw corrected for moisture content and season variation on the last workday of the month. The purchase sum for straw deliveries is due for payment on the 15th in the subsequent month. If the 15th is a Saturday, Sunday or other non-business day, payment will be effected on the following workday.

Weight certificates are issued by weighing.

6. WARRANTIES AND LIABILITIES

6.1 Equipment And Property Damage

Buyer/Seller shall be responsible for, and shall indemnify Seller/Buye**r** for, any and all direct reasonable costs resulting from damage to:

1) Seller's or its contracted carriers' equipment if such equipment is damaged while on Buyer's property to the extent such damage is caused by the negligence of Buyer.
2) Buyer's equipment and property, including mobile and stationary equipment at Buyer's electric generating station, to the extent such damage is caused by the negligence of Seller.

6.2 Express Warranties:

BUYER AGREES THAT SELLER MAKES NO EXPRESS WARRANTIES OTHER THAN THOSE SET FORTH IN THIS AGREEMENT.

6.3 Implied Warranties:

ALL WARRANTIES OF MERCHANTABILITY OR OF FITNESS FOR A PARTICULAR PURPOSE OR ARISING FROM A COURSE OF DEALING OR USAGE OF TRADE ARE SPECIFICALLY EXCLUDED.

6.4 Limitation of liability:

IN NO EVENT SHALL EITHER PARTY HAVE LIABILITY TO THE OTHER PARTY FOR INCIDENTAL OR CONSEQUENTIAL DAMAGES.

6.5 Non-Disclosure:

Neither party shall disclose any information regarding any part of this Agreement to any unrelated third party without the prior consent of the other, except: as required by law; as required by jurisdictional regulation pursuant to the request of any regulatory authorities (including, without limitation, state utility commissions or boards, the Federal Energy Regulatory Commission, the U.S. Securities and Exchange Commission and tax authorities); to attorneys, auditors, consultants or other outside experts of the parties if said individuals are advised of the confidential nature of the information and said individuals agree to maintain the confidentiality of the information; or to generating unit co-owner(s).

6.6 Applicable Laws:

This Agreement shall be subject to and governed by the laws of the State of Iowa.

6.7 Enforcement:

The Seller agrees that in light of Alliant Energy Corporate Services, Inc.'s agency relationship with IES, in the event of a default by Seller of any of the provisions of this Agreement, Alliant Energy Corporate Services, Inc., IES, may, at their sole discretion, individually or in any combination enforce the provisions of this Agreement.

7. COMMUNICATIONS BETWEEN THE PARTIES:

All communications related to this Agreement shall be to the persons listed below or to such other persons as the parties may specify in writing:

BUYER:	SELLER:
General Manager	____________________
Fuel Procurement	____________________
Alliant Energy Corporate Services, Inc.	____________________
P.O. Box 192	____________________
Madison, WI 53701-0192	____________________
(608) 252-3141	

8. SUCCESSORS AND ASSIGNS:

This Agreement shall insure to the benefit of and be binding upon the parties hereto and their respective successors and assigns; provided, however, this Agreement may not be assigned by either party hereto without the prior written consent thereto of the other party hereto, which consent shall not be unreasonably withheld, except in the following cases where no such consent will be required: pledge, assignment or other security arrangements to secure indebtedness incurred for the purpose of or in connection with performance under this Agreement, specifically including any financing arrangements deemed advisable by Buyer or Seller, such as development carveouts and production payments; provided, however, the assignor shall remain liable for all of its obligations hereunder; assignment to a successor or surviving corporation in connection with a merger, consolidation, sale of substantially all of the assets, divestiture pursuant to an order or decree of a court or administrative agency, or similar corporate reorganization or assignment by operation of law; provided, however, no such assignment shall be effective unless and until such assignee shall assume in writing all of the obligations of the assignor hereunder, and further provided that the assignor shall remain liable for all of its obligations hereunder; and assignment to a subsidiary or affiliated company (at least fifty percent (50%) owned or under common control) by a party hereto, wherein the subsidiary or affiliated company assumes in writing the obligations of the assignor; provided, however, the assignor shall remain liable for all of its obligations hereunder.

9. CONSIDERATION:

The sole consideration payable by Buyer for all biomass sold under this Agreement. Seller shall not seek to collect any other or additional amounts therefore, on any basis whatsoever.

10. MISCELLANEOUS:

No modification or change herein shall be enforceable, except as specifically provided for in this Agreement unless expressed in writing and executed by both parties. The headings used in this Agreement are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of any provision of this Agreement.

11. ENTIRE AGREEMENT:

This Agreement constitutes the entire agreement and understanding between the parties and supersedes and replaces all prior negotiations and agreements, whether written or oral.

BUYER:	SELLER:
Alliant Energy Corporate Services, Inc.,	______________________
Agent for IES Utilities, Inc.,	______________________
Wisconsin Power and Light Company,	______________________
And Interstate Power Company	______________________
NAME: ______________________	NAME: ______________________
TITLE: ______________________	TITLE: ______________________
DATE: ______________________	DATE: ______________________

APPENDIX B

Draft Independent Contractor Agreement

INDEPENDENT CONTRACTOR AGREEMENT

THIS AGREEMENT by and between Prairie Lands Bio-Products, Inc. (Prairie Lands) and Mr. _______________________ (Contractor) shall be in full force and effect on and after the date of its final execution.

WITNESSETH:

WHEREAS, Prairie Lands is cooperating with land owners in the Chariton Valley Biomass Project underway in southern Iowa, and the Contractor has agreed to perform services under the terms and conditions set forth herein,

NOW, THEREFORE, IT IS AGREED:

1. Term of Agreement. The Contractor shall complete the duties provided for by this agreement on or before ___________, unless the completion date is modified by agreement of both parties.

2. Scope of Contract. For the consideration set forth herein the Contractor agrees to perform the activities described in the Scope of Work as listed on Attachment A that, by this reference, is made part of this agreement. The Contractor shall provide his own tools and equipment required to perform the Scope of Work activities. Performance of the activities described in the Scope of Work are not assignable without the prior written consent of Prairie Lands.

3. Compensation. If the Contractor performs the duties, responsibilities, and all activities as set forth herein to the satisfaction of Prairie Lands, the Contractor will be compensated according to the rates included in the Scope of Work on Attachment A. The Contractor shall prepare and submit invoices in a format acceptable to Prairie Lands. Prairie Lands will issue payment to the Contractor, based on acceptance of invoices, within __ days of the invoice date.

4. Default. In the event that Prairie Lands determines that the Contractor is unable or fails to perform the duties, responsibilities, and activities set forth herein, Prairie Lands may declare any portion or all of this agreement null and void by providing the Contractor written communication. Upon the sending of such communication, this agreement shall be rendered null and void and of no further force and effect.

5 Independent Contractor. The Contractor shall perform the services rendered hereunder as an independent contractor and not as an employee of Prairie Lands or the federal government; accordingly, Contractor waives any benefits which might otherwise be receivable if he was determined to be an employee of Prairie Lands or the federal government, including but not limited to any worker's compensation benefits, social security contributions, or unemployment compensation benefits.

6. Operations. The Contractor agrees to adequately insure and safely operate, maintain, and repair facilities, supplies, materials, and equipment related to and acquired through this agreement.

7. Assets. The Contractor agrees not to mortgage, use as collateral, or borrow against supplies, materials, facilities, or equipment provided by Prairie Lands through this agreement.

8. Legal. Prairie Lands and the Contractor agree to comply with all applicable local, state, and federal ordinances, regulations, and laws.

9. Liability. The Contractor agrees to assume all risks in connection with the performance of the activities undertaken through this agreement and to be responsible for all claims, demands, actions, or causes of action of whatsoever nature or character arising out of or by reason of the execution or performance of the activities provided herein.

10. Intent to Cooperate. It is the intent of Prairie Lands and the Contractor to fulfill their obligations under this agreement. However, neither Prairie Lands nor the Contractor shall be obligated beyond funds available.

11. Amendment. The terms and conditions of this agreement may be modified by amendment agreed to in writing by both Prairie Lands and Contractor.

12. Certifications: Contractor will complete and submit to Prairie Lands all required and applicable certifications that may include, but are not limited to, the following: Assurance of Compliance Nondiscrimination in Federally Assisted Programs, Disclosure of Lobbying Activities, Certifications Regarding Lobbying; Debarment, Suspension and Other Responsibility Matters; and Drug-Free Workplace Requirements, and W-9 Request for Taxpayer Identification Number and Certification, copies of which are included in Attachment B. Contractor shall ensure the completion and submittal to the RC&D of applicable certifications from any subcontractor(s).

13. Civil Rights Act. The activities conducted under this agreement shall be in compliance with the nondiscrimination provisions contained in the Titles VI and VII of the Civil Rights Act of 1964, as amended, the Civil Rights Restoration Act of 1987 (Public Law 100-259); and other nondiscrimination statutes: namely, Section 504 of the Rehabilitation Act of 1973, Title IX of the Education Amendments of 1972, and the Age Discrimination Act of 1975. They will also be in accordance with regulations of the Secretary of Agriculture (7 CFR-l5, Subparts A and B), which provide that no person in the United States shall on the grounds of race, color, national origin, age, sex, religion, marital status, or handicap be excluded from participation in, be denied the benefits of, or be otherwise subjected to discrimination under any program or activity receiving federal financial assistance from the Department of Agriculture or any agency thereof.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed:

For:	For:
Prairie Lands Bio-Products, Inc. (Prairie Lands)	________________________ (Contractor)
________________________	________________________
________________________ Date	________________________ Date

Attachment A

Scope of Work

1. Perform all operations according to recommendations provided by representatives of Prairie Lands.

2. Perform all activities, including but not limited to, mow, rake, bale, stage, load, transport, unload, store, and reclaim, required to harvest and deliver to an agreed to location, up to ____ tons of biomass with the following specifications:

   - ___% large square bales – plastic twine (dimensions __ ft x __ ft x __ ft)
   - Maximum moisture content: __% by weight
   - Maximum inorganic/trash content: __% by weight
   - Negligible rotten material and wet spots

   Note: Prairie Lands reserves the right to refuse acceptance of any biomass that does not meet these specifications.

3. All biomass will be delivered to, and stored at the Ottumwa Generating Station (OGS) of off-site facilities as directed, that is, <u>at the time and rate requested</u>, by representatives of Prairie Lands.

4. The Contractor will participate in field by field harvest plan development and review with representatives of Prairie Lands.

5. The Contractor will assist with the collection of harvest and yield related data and biomass samples as requested by Prairie Lands.

6. Prairie Lands will compensate the Contractor as described below for the satisfactory completion of the activities set forth in this agreement:

   a. Biomass delivered directly to OGS, that is, biomass that is <u>not</u> stored in off-site facilities, will be compensated at $___ per ton.

   b. Biomass delivered to OGS that has first been stored in off-site facilities will be compensated at $___ per ton. Of this amount, $___ per ton will be paid to the Contractor once biomass is placed in an off-site storage facility. The balance of $___ per ton will be paid to the Contractor once the biomass is delivered to OGS.

APPENDIX C

Terms and Conditions for Delivery of Straw to Studstrup Power Plant, Denmark

MEMO

Distribution:
CVRC&D: Marty Braster
Alliant Energy: Bill Morton
TW: POV, NIK

March 19, 2001

Phone: +45 79 23 33 33
Fax: +45 75 56 44 77

Our ref.: NIK/DTH
Project no.: 12884

Verified: NIK

Terms and Conditions for Delivery of Straw to Studstrup Power Plant January 2001

1 General Terms

These terms and conditions constitute the requirements made for delivery of straw to Studstrup power plant.

Straw from rye, wheat, barley, oat, rape and seed grasses will be accepted, however, maximum 4 of the 12 straw bales in each layer may be rape or seed grass straw, unless otherwise agreed.

It is presupposed that the straw does not contain any large foreign bodies and that no ammonia or other chemicals have been added after the bales have been pressed.

2 Terms of Delivery

2.1 Place of Delivery

The place of delivery is specified in the corresponding contract.

2.2 Transport of Straw

To avoid obstruction of the traffic by delivery to Studstrup power plant, transport vehicles are referred to access mainly via Grenaavej-Skovlundvej-Studstrupvej.

To avoid spillage of straw, lorries should be covered by nets. The mesh size should not be more than 20 mm (0.75 inch).

When unloading at the straw storage of the power plant, the supplier is registered in a data terminal by means of an ID card. The straw storage is supplied with two unloading cranes and the unloading is carried out by the power plant.

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Kraftværksvej 53
DK-7000 Fredericia

Before leaving the storage building, the driver will get a receipt for the load according to agreement. The following information will be given on the receipt:

- Weight of the straw in kilo;
- Moisture content of the straw in percentage;
- Supplier;
- Date and time;
- Consecutive numbering.

2.3 Size of the Straw Bales

The straw bales are to be delivered as big-bales with the following dimensions:

Width: min. 120 cm (47.25 inch), max. 130 cm (51.20 inch)
Height:min. 125 cm (49.20 inch), max. 135 cm (53.15 inch)
Length: min. 225 cm (88.60 inch), max. 255 cm (100.40 inch)*
Weight: min. 400 kg (880 lbs), max. 1100 kg (2423 lbs)

* The aim is to have as little variation in length as at all possible.

In years with extreme weather conditions, it may be accepted that a few bales in each load have a minimum weight of as little as 350 kg/bale (772 lbs/bale).

2.4 Moisture Content of the Straw Bales

The straw bales should have as low a moisture content as possible. The moisture content is measured during weighing by the measuring equipment installed in the cranes. Each measurement is made as an average across two bales. At each straw gripping device the moisture content is measured from several representative places. The average moisture content of two straw bales is not to exceed 20%. Not even one measurement of a moisture content of 23% or above made in the straw gripping device will be accepted, and the layer of straw bales or the load, respectively, will be refused.

Test measurements can be made by inserting the moisture-measuring spear into the straw bales at a place chosen by the controller. Measurements are not to be made in the outermost 5 cm (2 inch) of the straw bale. If the moisture content of two manual test measurements made at an interval of 30 cm (12 inch) exceeds 30%, the layer of straw bales or load, respectively, will be refused at the reception area.

The moisture content of a load of straw for settlement is registered during the receipt by means of a microwave system. A moisture content below 10% cannot be registered. If the microwave system breaks down, the power plant personnel will measure the moisture content by inserting moisture-measuring spears at 10 different locations in

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each load. The average of these 10 measurements will be valid. The result of the manual measurement is registered in the power plant's registration system and settlement will take place as usual.

2.5 Loading of the Straw Bales

Each transport is to carry 24 straw bales loaded as follows:

- 12 straw bales on the forecarriage and 12 straw bales on the trailer;
- closely packed;
- longitudinally on the truck;
- along the longitudinal centerline of the truck;
- close towards the front of the truck;
- in two layers only;
- in such a way that the bales are not staggered;
- the straw bales are to be standing on the twines;
- the lower layer of straw bales in a batch should be placed with the lower side up;
- displacements (the upper edge of the truck floor) between forecarriage and trailer are not to be more than 10 cm.

Transport with more than 20 bales of straw on a semi-trailer may be accepted subject to further agreement.

2.6 Rejection Criteria

The straw transport may be rejected if:

- the straw bales deviate from the criteria for size (cf. section 2.3);
- the moisture content of the straw bales is too high (cf. section 2.4);
- the straw bales are not loaded correctly (cf. section 2.5);
- the straw bales contain non-combustible material;
- the twines around the bales are mouldering;
- the straw bales on visual inspection deviate from a normally satisfactory quality, e.g. due to putrefaction.

If the straw transport is rejected, information will be given about which bales caused the rejection.

If a supplier considers a rejection to be unacceptable, the supplier can demand additional inspection supervised by the logistics officer of the power plant and the supplier. A report will be prepared in case of rejection.

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If a layer of straw is rejected, the supplier is to bear all expenses connected with cleanup and disposal of the load, including covering of the rejected straw layer by a net. If the straw bales have been unloaded, the power plant is responsible for cleanup, etc.

If straw loads are repeatedly rejected on the above grounds, this is considered a breach of contract and entitles the buyer to terminate the agreement and to purchase a replacement supply on the supplier's account.

2.7 Vehicles

Transport of straw by tractor is not permitted unless otherwise agreed.

The fully loaded trains of carriages are not to exceed the following dimensions:

Length by unloading:	18.75 m (62 feet)
Width:	3.00 m (10 feet)
Height:	4.00 m (13 feet)

Unloading of the trains of carriages must be possible from any of the sides and from the back. (E.g. the train of carriage must not have a rear-mounted crane on the forecarriage/trailer).

After unloading, all trains of carriages are to be cleaned by their drivers before leaving the unloading area. A vacuum cleaner is available for this purpose. Any littering of the area and road is to be avoided.

Any possible environmental requirements in connection with the transport are the responsibility of the carrier.

2.8 Opening Hours

The power plant will be open for receipt of straw bales on all normal workdays between 7 a.m. and 6 p.m. as well as on Saturdays between 7 a.m. and 2 p.m. Receipt of straw bales outside these hours may only take place according to special agreement.

The trains of carriages are not to arrive at the gate of the power plant before 7 a.m. and are to be out of the gate at the latest at 6 p.m. on workdays and at 2 p.m. on Saturdays.

If the unloading system of the power plant is out of operation, the waiting time can be settled at 350 DKK/hour pro rata according to agreement with the logistics officer of the power plant. As is the case for the basis price of straw, the rate for waiting time is adjusted once a year on August 1 by the net consumer-price index minus 1.5%-point.

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2.9 Miscellaneous

All drivers must be familiar with the safety regulations of the power plant, which can be requisitioned at the plant.

Directions given by the power plant personnel must be complied with.

3 Delivery Schedules

Delivery takes place according to agreement with the logistics officer of the power plant during the period specified in the corresponding contract.

In July/August the power plant issues a draft delivery schedule. The draft specifies the supplier's delivery period. The supplier's wishes can to some extent be considered during the planning phase.

At the latest two workdays before delivery of straw is to be commenced, the supplier will be contacted by the logistics officer of the plant with a view to further details of the time and amount of delivery per day.

In case of suspension of or reduction in the straw delivery or supply, the other party is to be informed of this immediately as well as of the reason for and the expected duration of the suspension or reduction.

If transport of a load has been commenced, the load is to be considered as delivered and the power plant is thus to accept the load (unless the load is rejected in accordance with section 2.6).

Force Majeure

The parties are not liable if force majeure occurs after the agreement has been made.

By force majeure is to be understood - according to this contract – any circumstances beyond the control of the parties including unusual natural phenomena (Acts of God), fire in straw storages, faults in or breakdown of the bio-boiler of the power plant including reception system, restrictions on heat sales or the like at the power plant which renders impossible the receipt and combustion of straw.

In case of force majeure each of the parties are exempted in whole or in part from their obligation to deliver or purchase.

The party wishing to claim force majeure is to inform the other party in writing and without undue delay of the accrual of the force majeure and the expected cessation of the force majeure.

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The reason for the force majeure is to be documented in writing.

If the power plant reduces the supplies, this reduction is to be made proportionately for all suppliers.

4 Pricing and Terms of Payment

4.1 Pricing

The straw is settled based on the contract basis price.

The basis price is adjusted once a year on August 1 (the first time on August 1, 2004) by the annual increase in the net consumer-price index minus 1.5%-point. The annual increase is calculated on basis of the increase in the net consumer-price index from April 1 till March 31 minus 1.5%-point. It will not be possible to adjust the basis price downward.

As specified in the contract, the basis price is adjusted during the delivery season by means of season variation and weight correction as follows:

Season variation

In the period August 1 to August 31 the delivery price is equal to the basis price. For delivery in the subsequent months, the price is increased by a monthly addition. The monthly addition is calculated each month of the delivery year based on the following equation:

$$(Basis\ \ price) \times \frac{delivery\ month - 1}{12} \times (discount\ \ rate + 5)\%$$

The addition is calculated in whole kroner (Danish currency). The monthly additions in the delivery year are calculated at the start of the delivery season on basis of the average discount rate + 5% during the preceding period from April 1 to March 31.

Weight Correction

The weight registered during the weighing is adjusted for moisture as follows:

The basis price applies to 13% moisture content. 13% moisture content covers the range from 12.5 to 13.4%. 14% moisture content covers the range from 13.5 to 14.4%, etc.

If the average moisture content is less than 13%, the weight is corrected by 2% for each 1% reduced moisture content. Moisture content below 10% cannot be measured. If the moisture content is more than 13% the weight is corrected by -2% for each 1% increased moisture content.

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Example: Moisture content 11%: the weight is increased by 4%.
Example: Moisture content 16%: the weight is reduced by 6%.

4.2 Terms of Payment

The power plant specifies a statement of delivered straw corrected for moisture content and season variation on the last workday of the month. The purchase sum for straw deliveries is due for payment on the 15^{th} in the subsequent month. If the 15^{th} is a Saturday, Sunday or other non-business day, payment will be effected on the following workday.

Weight certificates are issued by weighing.

It must be possible to transfer the purchase amount for straw deliveries to a Danish bank.

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APPENDIX D

Financial Analysis Inputs

APPENDIX D - Financial Analysis Inputs
Deliverable #3 - Fuel Supply Contracts

Coal Information - Existing			Reference
Gross Power Output (MW)		725.0	1
Net Power Output (MW)		675.0	1
Net Plant Heat Rate (Btu/kWh)		10,828	5
Unit Capacity Factor (%)		xxxx%	1
SOX Emissions (lb/MMBtu)		xxx	3
Ash (lb/MMBtu)		7.09	3
Avg. Coal Price ($/MMBtu)	$	0.90	5
As Received HHV of Coal (Btu/lb)		xxxxx	5
Avg. O&M Price, fixed & variable (exclusive of fuel) ($/kWh)	$	0.005	7
Value of Ash ($/ton)	$	xxxx	5
Ash Disposal Liability ($/ton)	$	xxxxx	5
Ash sales lost by Cofiring for Base Case		0%	assumed
Ash sales lost by Cofiring for Alternate #1		100%	assumed

Switchgrass Related Information		Reference
Annual Biomass Supply (tons/year)	200,000	6
Switchgrass Capacity Factor	91.3%	calculated
Switchgrass Fuel Supply Rate to Boiler (ton/hr)	25.0	calculated
Avg. Cofiring Percentage (%) - Heat Basis	6.2%	calculated
Avg. Cofiring Percentage (%) - Mass Basis	6.1%	calculated
BioPower Electrical Generation (MW)	41.6	calculated
As Received HHV Biomass (Btu/lb)	7,458	3
Boiler Efficiency Losses due to Cofiring		
Use Tillman/EPRI Equation for Efficiency Losses? (Y/N)	Y	10
Fouling Losses due to Biomass (%)	0.10%	11
Efficiency Losses due to Biomass (%)	0.07%	11
Net Change in Heat Rate (Btu/kWh)	6	10

Switchgrass O&M Cost Information			Reference
Additional manpower required (no. of workers)		3	
Annual compensation per worker ($) (loaded rate)	$	75,000	
Maintenance Costs ($)	$	306,178	12
Administration & Insurance	$	150,000	assumed

Switchgrass Capital Cost Information			Reference
Total Est. Cost for Receiving & Processing Equipment ($)	$	15,308,900	2
Federal Cost-Share Rate on Capital Equipment & Installation		100%	6
Federal Cost-Share on Capital Equipment & Installation	$	15,308,900	
No. of Years for Capital Recovery (yrs)		20	assumption
Interest Rate for Borrowing (APR, %)		5.5%	assumption

Comparative Cost Information			Reference
Cost of Electricity from Class 4 Wind Farms (max.)	$	0.0495	8
Cost of Electricity from Class 4 Wind Farms (min.)	$	0.0288	8

Regulatory Incentives			Reference
Production Tax Credit ($/kWh)	$	0.018	9
Value of SO_2 Credits ($/ton)	$	150	4
Risk and Incentive Factors to Alliant from project ($/yr)	$	(150,000)	6

References:

1. World Electric Power Plants Database, Utility Data Institute / McGraw-Hill Companies, June 1999
2. Bradford Conrad Crow Engineering, Cost Estimate, July 2002
3. Amos, Wade, National Renewable Energy Laboratory, Data from December 2000 Test Burn, February 2002
4. http://www.cleanerandgreener.org/environment/so2.htm
5. Values provided by Alliant Energy via email correspondence with Patrick Wright, April 2002
6. Values provided by CVRC&D
7. EIA, Office of Coal, Nuclear, & Alt. Fuels, "Financial Statistics of Major US Investor-Owned Electric Utilities", 1996, Table 14.
8. American Wind Energy Association, http://www.awea.org/faq/cost.html, High number based on private ownership, project financing, and with PTC, Low number based on public utility ownership, internally financed with PTC
9. Renewable Resources Electricity Credit of 1.5 cents per kWh of energy generated with closed-loop biomass, based upon proposed modifications to section 45 of the Internal Revenue Code. The value of 1.5 cents in 1992 is equal to 1.8 cents in 2002.
10. Plasynski, Sean, Raymond Costello, Evan Hughes, and David Tillman; "Biomass Cofiring in Full-Sized Coal-Fired Boilers", 1998
11. Alliant Energy data and assumptions
12. Bain, Richard, Kevin Craig, and Kevin Comer; "Renewable Energy Technology Characterizations", 1997, p 2-40 to 2-46.

APPENDIX E

Financial Analysis Results

Base Case Scenario - Output & Calculations

Unit Specifications - Current Operations (Coal Only)		Value	Reference
Gross Power Output (MW)		725.0	1
Net Power Output (MW)		675.0	1
Net Plant Heat Rate (Btu/kWh)		10,828.0	7
Unit Capacity Factor		xx%	7
Gross Generation (GWh)		4,801	calculated
Net Generation (GWh)		4,470	calculated
Heat Input (MMBtu/yr)		xx,xxx,xxx	calculated
Annual Coal Consumption (tons)		x,xxx,xxx	calculated
SOX Emissions (lb/MMBtu)		x.xx	3
Ash (lb/MMBtu)		7.09	3
SOX Emissions (tons/year)		22,508	calculated
Ash (tons/year)		171,535	calculated
As Received HHV of Coal (Btu/lb)		8,400	3
Avg. Coal Price ($/MMBtu)	$	0.90	7
Avg. Coal Price ($/ton)	$	xx.xx	calculated
Annual Fuel Costs	$	43,563,266	calculated
Parasitic Load (MW)		50	calculated
In House Electricity Use (kWh/yr)		331,128,000	calculated
Electricity Generation Price ($/kWh) (Production Cost)	$	0.015	calculated
Avg. Fuel Cost ($/kWh)	$	0.010	calculated
Avg. O&M Price (exclusive of fuel) ($/kWh)	$	0.005	10
Avg. Annual O&M Expenditures (exclusive of fuel) ($)	$	24,006,780	calculated
Revenue from Power Sales ($/yr)	$	67,053,420	calculated
Percent of Ash Sales		100%	assumed
Value of Marketed Ash ($/ton)	$	xxx	7
Current Revenue from Ash Sales	$	xxx	calculated
Ash Disposal Liability ($/ton)	$	xxx	7
Current Annual Ash Disposal Liability	$	xxx	calculated
Net Annual Cash Flow from Ash Management	$	xxx	calculated
Ash sales lost by Cofiring		0%	assumed

Unit Specifications - Projected Cofiring & Biomass Data		Value	Reference
As Received HHV Biomass (Btu/lb)		7,458	3
Biomass Usage (tons/yr)		200,000	assumed
Net BioPower Produced Annually (kWh/yr)		275,362,632	calculated
Cofiring Rate (Biomass Heat Input %) - Avg		6.2%	calculated
Fouling Losses due to Biomass (%)		0.10%	15
Change in Heat Rate due to Fouling (Btu/kWh)		3	calculated
Other Specified Efficiency Losses due to Biomass (%)		0.07%	15
Change in Heat Rate due to Efficiency Loss (Btu/kWh)		2	calculated
Total Change in Heat Rate (Btu/kWh)		6	14
Annual Increase in Heat Input due to Fouling (MMBtus)		15,257	calculated
Annual Increase in Heat Input due to Efficiency Losses (MMBtus)		10,680	calculated
Unplanned Annual Increase in Heat Input due to Efficiency Losses (MMBtus)		0	calculated
Cofiring Heat Requirement (MMBtu / yr)		48,429,172	calculated
Heat input from coal (MMBtu / yr)		45,444,397	calculated
Heat input from biomass (MMBtu / yr)		2,984,774	calculated
Change in Coal Usage to Maintain Load (tons)			
Coal only usage (tons)		x,xxx,xxx	calculated
Cofiring usage (tons)		x,xxx,xxx	calculated
Total Change (tons)		(176,145)	calculated
Change in Emissions			
SOx Reductions (Tons/year)		1,376	calculated
SOx Reductions (%)		6.1%	calculated
Value of SOx Credits ($/ton)	$	150	6
Net Emissions Benefit ($)	$	206,406	calculated
Change in Plant Output			
Decrease in Coal Parasitic Load (MW)		-	calculated
Electric Benefit to OGS (kWh)		-	calculated
Increase in Biomass Parasitic Load (MW)		-	calculated
Electric Cost to Prairie Lands (kWh)		-	calculated
Net Change (MW)		-	calculated
Other Plant Parasitics (kWh)		331,128,000	calculated

EXPENSE ANALYSIS FOR BASE CASE SCENARIO

Fuel Costs				
Avg. Delivered Cost of Biomass ($/ton)	$	30.00	$	35.00
Annual Biomass Consumption (tons/yr)		200,000		200,000
Total Biomass Fuel Cost	**$**	**6,000,000**	$	7,000,000

O&M Costs			
Additional Personnel		3	
Annual Rate ($/man/yr)	$	75,000	assumed
Total Personnel Costs	$	225,000	calculated
Other O&M Costs			
Elect. For Increased Parasitic Load	$	-	calculated
Maintenance Costs ($)	$	306,178	16
Administration & Insurance	$	150,000	assumed
Total Other O&M Costs	$	456,178	calculated
Total Operating & Maintenance (O&M) Costs	**$**	**681,178**	calculated

Changes in Performance			
Fouling Factor (0.1%)	$	13,731	15
Efficiency (0.07%)	$	9,612	15
Unplanned Efficiency Losses	$	-	14
Ash Disposal Increase	$	-	calculated
Total Performance Change	**$**	**23,343**	calculated

Capital Expenditures			
Total OGS Installed Cost	$	15,308,900	2
Federal Cost Sharing Amount	$	15,308,900	9
No. of Years for Capital Recovery		20	assumed
Interest Rate for Borrowing		5.5%	assumed
Total Annual Debt Service	**$**	**-**	calculated

Expense Analysis				
Biomass Fuel Costs	$	6,000,000	$	7,000,000
O&M Costs	$	681,178	$	681,178
Electricity Purchases	$	-	$	-
Portion of Coal O&M Costs (6.2% of exist. Non-fuel O&M)	$	1,479,580	$	1,479,580
Changes in Performance	$	23,343	$	23,343
Total Annual Debt Service	$	-	$	-
Total Expenses	**$**	**8,184,101**	$	9,184,101

Potential Incentives				
Renewable Energy Production Tax Credit {PTC} ($/kWh)	$	0.0180	13	
Emission Reductions (SO_x) ($/kWh)	$	0.0007	calculated	
Risk and Incentive Factors ($/kWh)	$	(0.0005)	9	
Total Maximum Potential Revenue from Incentives	$	5,162,934	calculated	
Cost of Coal Power Electricity ($/kWh)	$	0.0150	$	0.0150
Cost of Wind Power Electricity - Class 4 Farm (high $/kWh)	$	0.0495	$	0.0495
Cost of Wind Power Electricity - Class 4 Farm (low $/kWh)	$	0.0288	$	0.0288

References:

1. World Electric Power Plants Database, Utility Data Institute / McGraw-Hill Companies, June 1999
2. Bradford Conrad Crow Engineering, Cost Estimate, July 2002
3. Amos, Wade, National Renewable Energy Laboratory, Data from December 2000 Test Burn, February 2002
6. http://www.cleanerandgreener.org/environment/so2.htm
7. Values provided by Alliant Energy via email correspondence with Patrick Wright, April 2002
9. The numbers for the risk factor and federal cost share amount were provided by CVRC&D
10. EIA, Office of Coal, Nuclear, & Alt. Fuels, "Financial Statistics of Major US Investor-Owned Electric Utilities", 1996
11. American Wind Energy Association, http://www.awea.org/faq/cost.html, High number based on private ownership, project financing, and with PTC. Low number based on public utility ownership, internally financed with PTC
13. Renewable Resources Electricity Credit of 1.5 cents per kWh of energy generated with closed-loop biomass, based upon proposed modifications to section 45 of the Internal Revenue Code. The value of 1.5 cents in 1992 is equal to 1.8 cents in 2002.
14. Plasynski, Sean, Raymond Costello, Evan Hughes, and David Tillman; "Biomass Cofiring in Full-Sized Coal-Fired Boilers", 1998
15. Alliant Energy data and assumptions
16. Bain, Richard, Kevin Craig, and Kevin Comer; "Renewable Energy Technology Characterizations", 1997, p 2-40 to 2-46.

Alternate #1 - 100% Ash Sales Lost - Output & Calculations

Unit Specifications - Current Operations (Coal Only)	Value	Reference
Gross Power Output (MW)	725.0	1
Net Power Output (MW)	675.0	1
Net Plant Heat Rate (Btu/kWh)	10,828.0	7
Unit Capacity Factor	xxx	7
Gross Generation (GWh)	4,801	calculated
Net Generation (GWh)	4,470	calculated
Heat Input (MMBtu/yr)	xx,xxx,xxx	calculated
Annual Coal Consumption (tons)	x,xxx,xxx	calculated
SOX Emissions (lb/MMBtu)	x.xx	3
Ash (lb/MMBtu)	7.09	3
SOX Emissions (tons/year)	22,508	calculated
Ash (tons/year)	171,535	calculated
As Received HHV of Coal (Btu/lb)	8,400	3
Avg. Coal Price ($/MMBtu)	$ 0.90	4
Avg. Coal Price ($/ton)	$ xx.xx	calculated
Annual Fuel Costs	$ 43,563,266	calculated
Parasitic Load (MW)	50	calculated
In House Electricity Use (kWh/yr)	331,128,000	calculated
Electricity Generation Price ($/kWh) (Production Cost)	$ 0.015	8
Avg. Fuel Cost ($/kWh)	$ 0.010	10
Avg. O&M Price (exclusive of fuel) ($/kWh)	$ 0.005	10
Avg. Annual O&M Expenditures (exclusive of fuel) ($)	$ 24,006,780	calculated
Revenue from Power Sales ($/yr)	$ 67,053,420	calculated
Percent of Ash Sales	100%	assumed
Value of Marketed Ash ($/ton)	$ xxx	7
Current Revenue from Ash Sales	$ xxx	calculated
Ash Disposal Liability ($/ton)	$ xxx	7
Current Annual Ash Disposal Liability	$ xxx	calculated
Net Annual Cash Flow from Ash Management	$ xxx	calculated
Ash sales lost by Cofiring	100%	assumed

Unit Specifications - Projected Cofiring & Biomass Data	Value	Reference
As Received HHV Biomass (Btu/lb)	7,458	3
Biomass Usage (tons/yr)	200,000	assumed
Net BioPower Produced Annually (kWh/yr)	275,362,632	calculated
Cofiring Rate (Biomass Heat Input %) - Avg	6.2%	calculated
Fouling Losses due to Biomass (%)	0.10%	15
Change in Heat Rate due to Fouling (Btu/kWh)	3	calculated
Other Specified Efficiency Losses due to Biomass (%)	0.07%	15
Change in Heat Rate due to Efficiency Loss (Btu/kWh)	2	calculated
Total Change in Heat Rate (Btu/kWh)	6	14
Annual Increase in Heat Input due to Fouling (MMBtus)	15,257	calculated
Annual Increase in Heat Input due to Efficiency Losses (MMBtus)	10,680	calculated
Unplanned Annual Increase in Heat Input due to Efficiency Losses (MMBtus)	0	calculated
Cofiring Heat Requirement (MMBtu / yr)	48,429,172	calculated
Heat input from coal (MMBtu / yr)	45,444,397	calculated
Heat input from biomass (MMBtu / yr)	2,984,774	calculated
Change in Coal Usage to Maintain Load (tons)		
Coal only usage (tons)	x,xxx,xxx	calculated
Cofiring usage (tons)	x,xxx,xxx	calculated
Total Change (tons)	(176,145)	calculated
Change in Emissions		
SOx Reductions (Tons/year)	1,376	calculated
SOx Reductions (%)	6.1%	calculated
Value of SOx Credits ($/ton)	$ 150	6
Net Emissions Benefit ($)	$ 206,406	calculated
Change in Plant Output		
Decrease in Coal Parasitic Load (MW)	-	calculated
Electric Benefit to OGS (kWh)	-	calculated
Increase in Biomass Parasitic Load (MW)	-	calculated
Electric Cost to Prairie Lands (kWh)	-	calculated
Net Change (MW)	-	calculated
Other Plant Parasitics (kWh)	331,128,000	calculated

EXPENSE ANALYSIS FOR ALTERNATE #1

Fuel Costs				
Avg. Delivered Cost of Biomass ($/ton)	$	30.00	$	35.00
Annual Biomass Consumption (tons/yr)		200,000		
Total Biomass Cost	**$**	**6,000,000**	$	7,000,000

O&M Costs			
Additional Personnel		3	
Annual Rate ($/man/yr)	$	75,000	assumed
Total Personnel Costs	$	225,000	calculated
Other O&M Costs			
Elect. For Increased Parasitic Load	$	-	calculated
Maintenance Costs ($)	$	306,178	16
Administration & Insurance	$	150,000	8
Total Other O&M Costs	$	456,178	calculated
Total Operating & Maintenance (O&M) Costs	**$**	**681,178**	calculated

Changes in Performance			
Fouling Factor (0.1%)	$	13,731	9
Efficiency (0.07%)	$	9,612	9
Unplanned Efficiency Losses	$	-	14
Ash Disposal Increase	$	x,xxx,xxx	calculated
Total Performance Change	**$**	**x,xxx,xxx**	calculated

Capital Expenditures		
Total OGS Installed Cost	$	15,308,900
Federal Cost Sharing Amount	$	15,308,900
No. of Years for Capital Recovery		20
Interest Rate for Borrowing		5.5%
Total Annual Debt Service		**$0.00**

Expense Analysis				
Biomass Fuel Costs	$	6,000,000	$	7,000,000
O&M Costs	$	681,178	$	681,178
Electricity Purchases	$	-	$	-
Portion of Coal O&M Costs (6.2% of exist. Non-fuel O&M)	$	1,479,580	$	1,479,580
Changes in Performance	$	x,xxx,xxx	$	x,xxx,xxx
Total Annual Debt Service	$	-	$	-
Total Expenses	**$**	**xx,xxx,xxx**	$	xx,xxx,xxx

Potential Incentives

Renewable Energy Production Tax Credit {PTC} ($/kWh)	$	0.0180	13
Emission Reductions (SO_x) ($/kWh)	$	0.0007	calculated
Risk and Incentive Factors	$	(0.0005)	9
Total Maximum Potential Revenue from Incentives	$	5,162,934	calculated

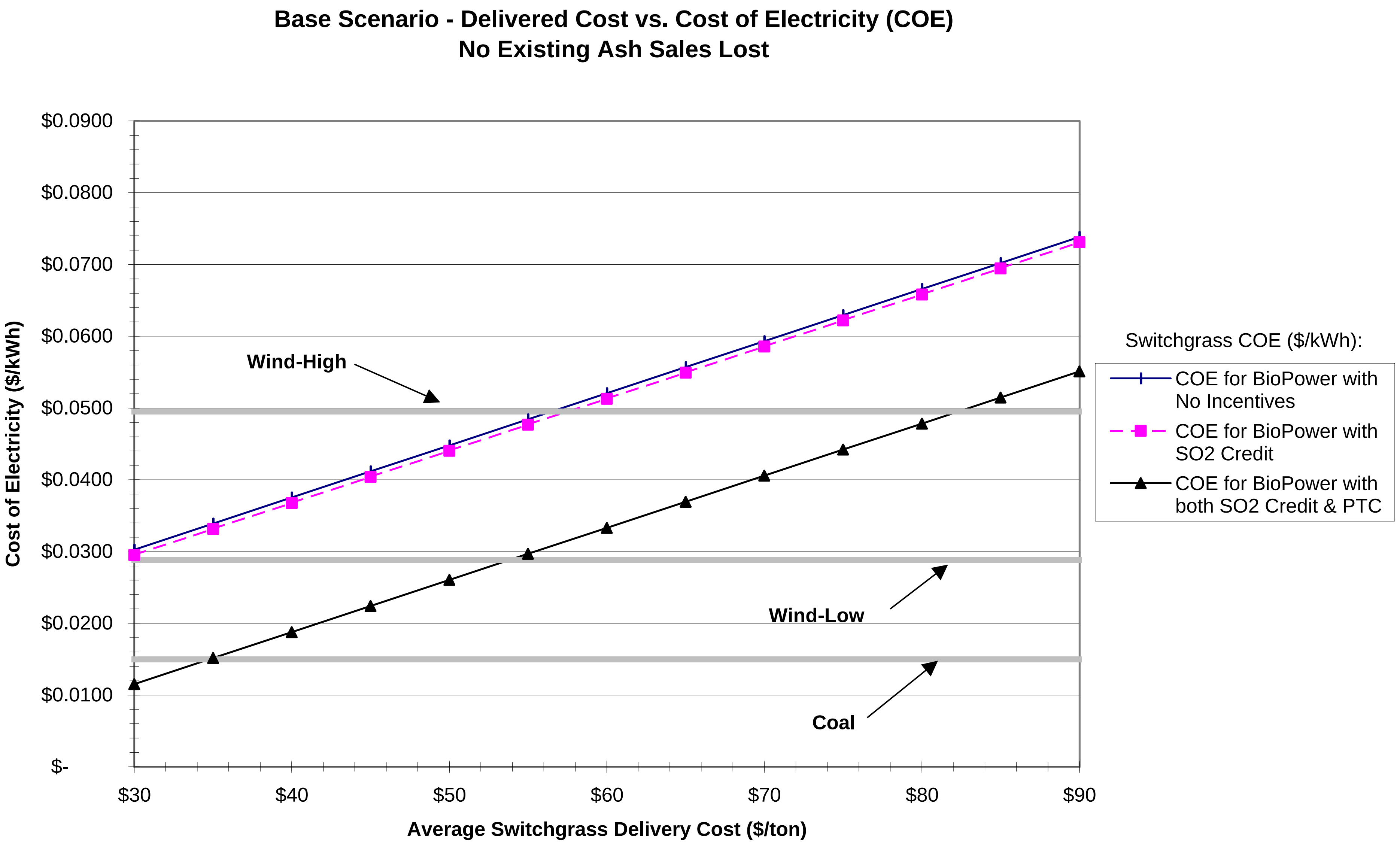
Cost of Coal Power Electricity ($/kWh)	$	0.0150	$	0.0150
Cost of Wind Power Electricity - Class 4 Farm (high $/kWh)	$	0.0495	$	0.0495
Cost of Wind Power Electricity - Class 4 Farm (low $/kWh)	$	0.0288	$	0.0288

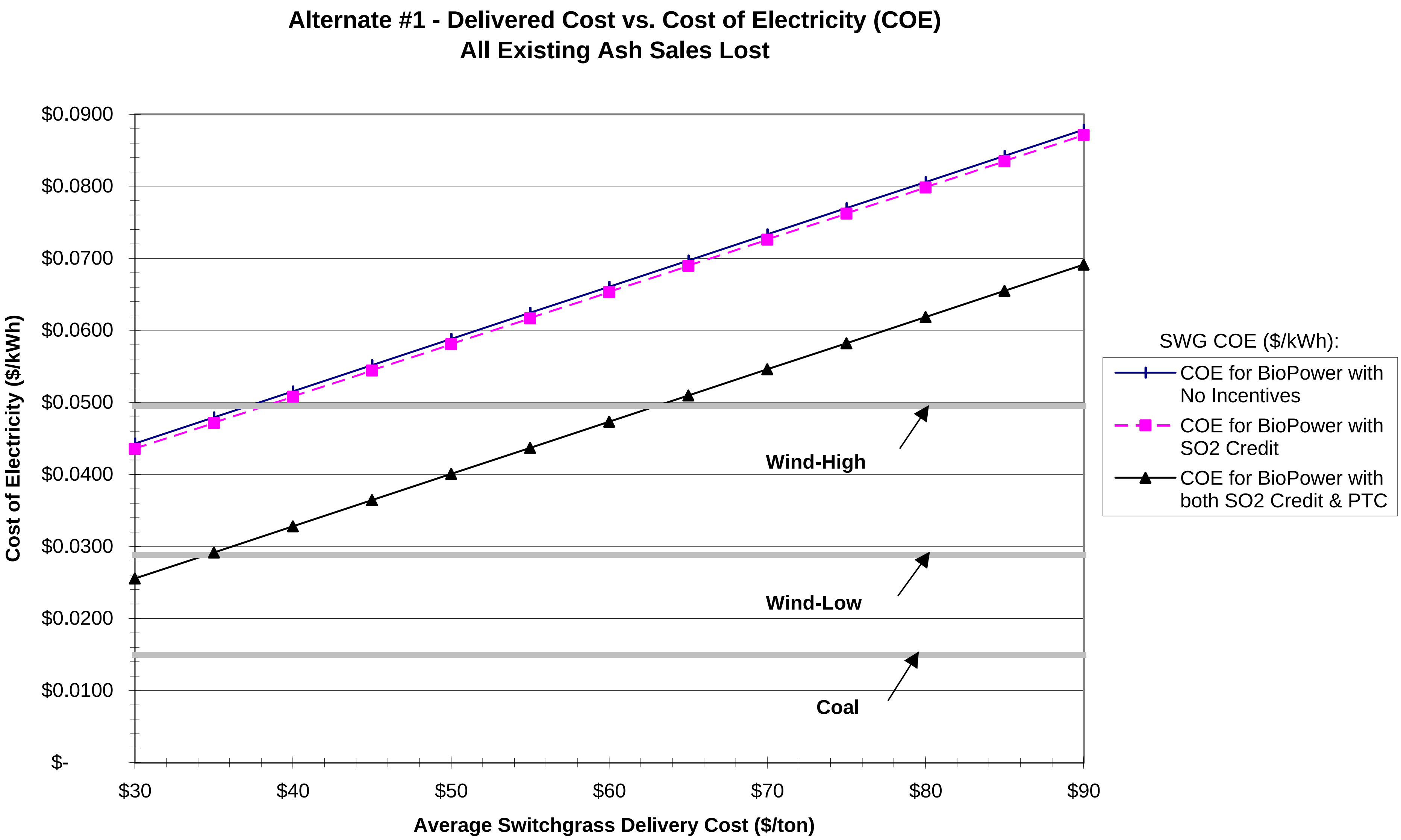
References:

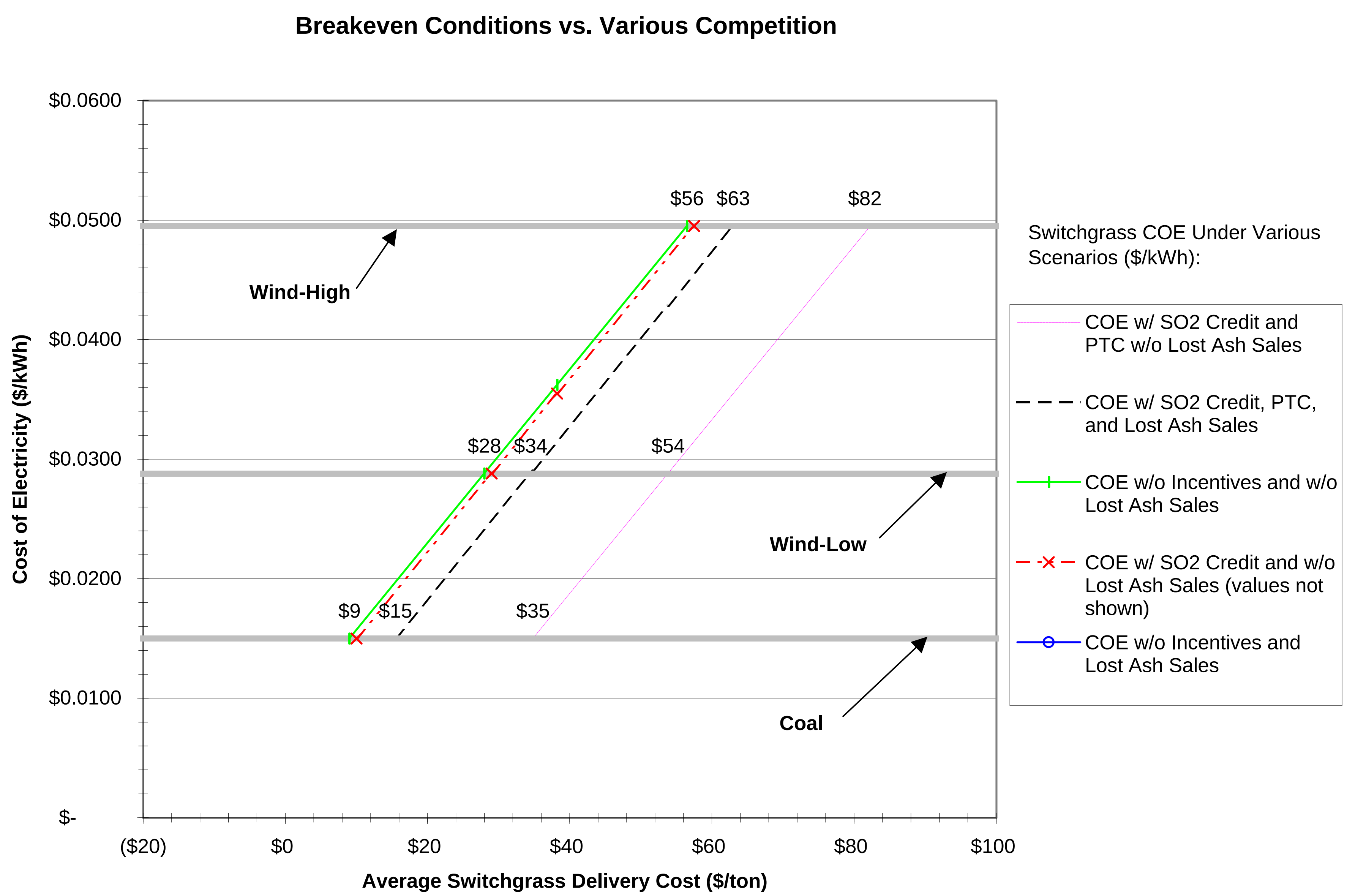
1. World Electric Power Plants Database, Utility Data Institute / McGraw-Hill Companies, June 1999
2. Bradford Conrad Crow Engineering, Cost Estimate, July 2002
3. Amos, Wade, National Renewable Energy Laboratory, Data from December 2000 Test Burn, February 2002
6. http://www.cleanerandgreener.org/environment/so2.htm
7. Values provided by Alliant Energy via email correspondence with Patrick Wright, April 2002
9. The numbers for the risk factor and federal cost share amount were provided by CVRC&D
10. EIA, Office of Coal, Nuclear, & Alt. Fuels, "Financial Statistics of Major US Investor-Owned Electric Utilities", 1996
11. American Wind Energy Association, http://www.awea.org/faq/cost.html, High number based on private ownership, project financing, and with PTC. Low number based on public utility ownership, internally financed with PTC
13. Renewable Resources Electricity Credit of 1.5 cents per kWh of energy generated with closed-loop biomass, based upon proposed modifications to section 45 of the Internal Revenue Code. The value of 1.5 cents in 1992 is equal to 1.8 cents in 2002.
14. Plasynski, Sean, Raymond Costello, Evan Hughes, and David Tillman; "Biomass Cofiring in Full-Sized Coal-Fired Boilers", 1998
15. Alliant Energy data and assumptions
16. Bain, Richard, Kevin Craig, and Kevin Comer; "Renewable Energy Technology Characterizations", 1997, p 2-40 to 2-46.

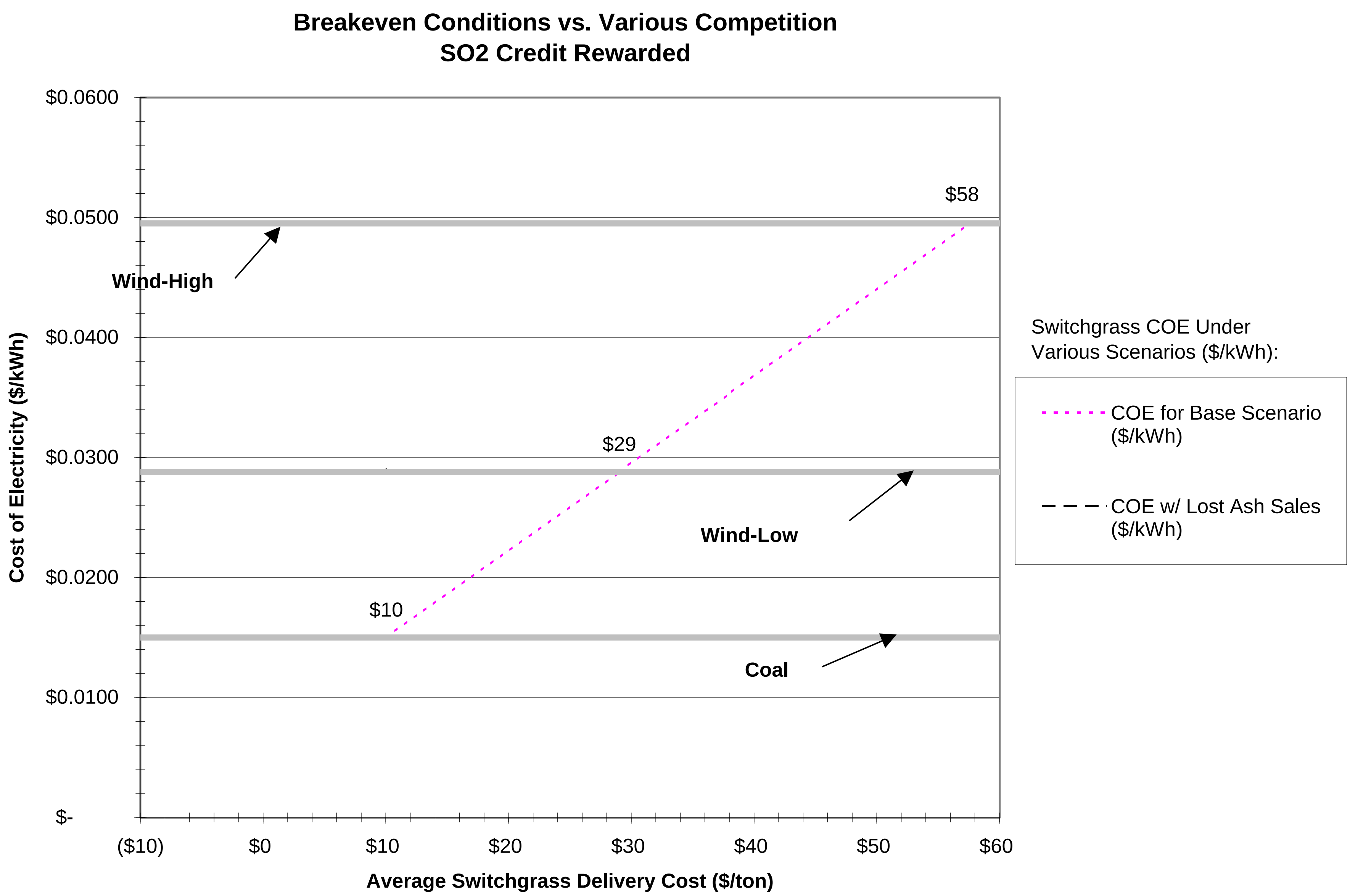
APPENDIX F

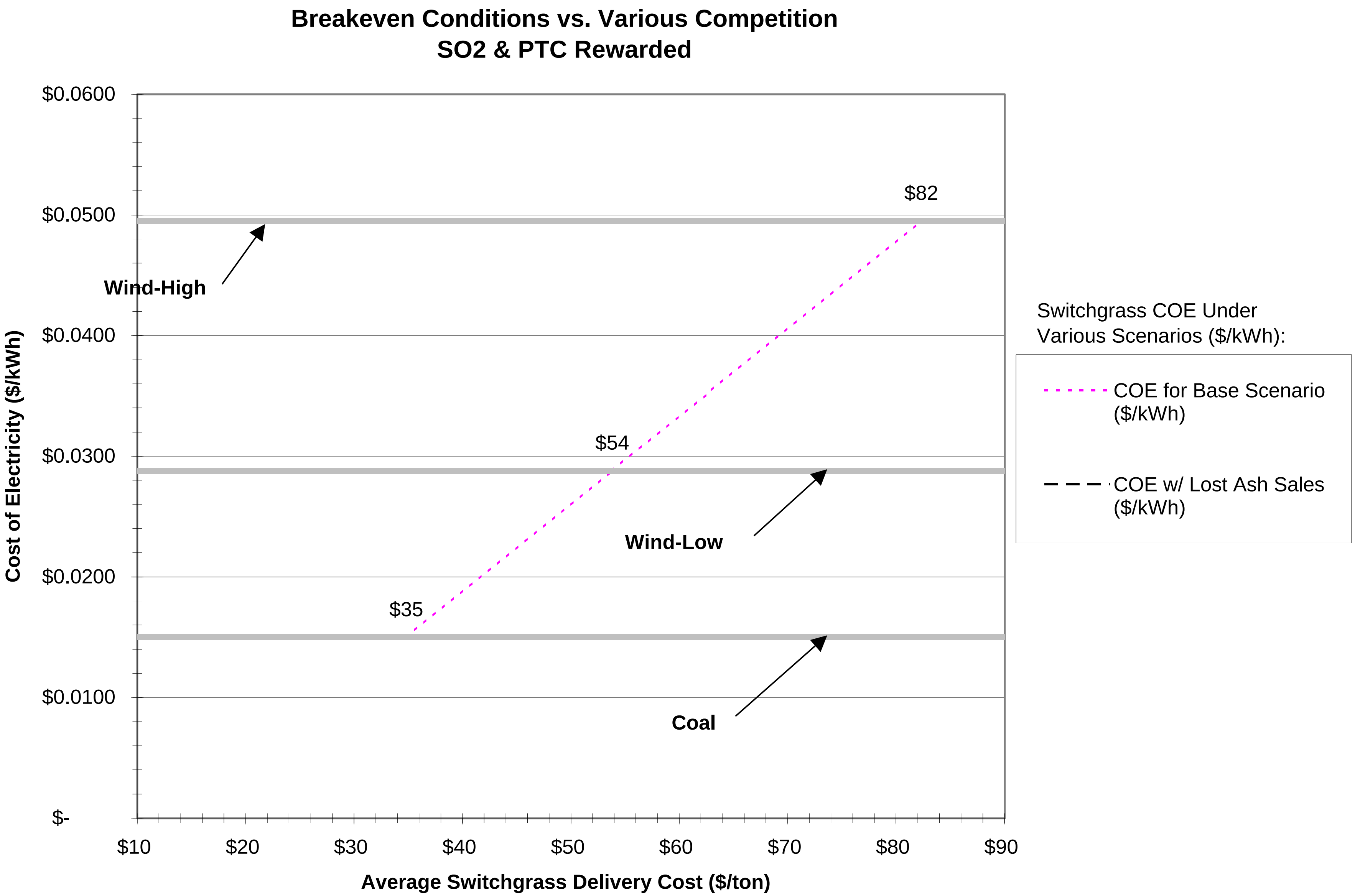
Financial Analysis Graphs


Base Scenario - Delivered Cost vs. Cost of Electricity (COE)
No Existing Ash Sales Lost
Cost of Electricity ($/kWh)
$0.0900
$0.0800
$0.0700
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
$30
$40
$50
$60
$70
$80
$90
Average Switchgrass Delivery Cost ($/ton)
Wind-High
Wind-Low
Coal
Switchgrass COE ($/kWh):
COE for BioPower with No Incentives
COE for BioPower with SO2 Credit
COE for BioPower with both SO2 Credit & PTC

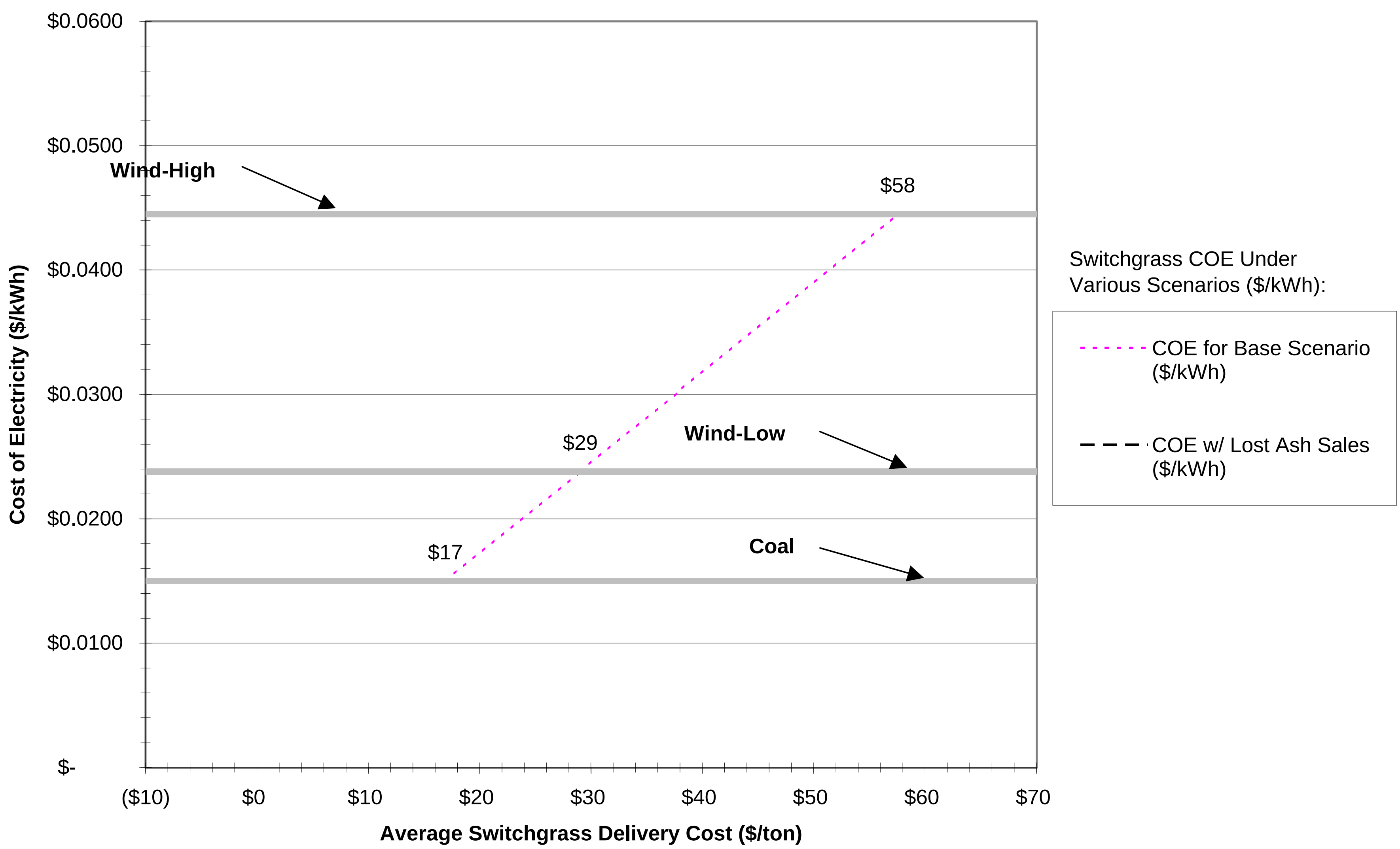

Alternate #1 - Delivered Cost vs. Cost of Electricity (COE)
All Existing Ash Sales Lost
Cost of Electricity ($/kWh)
$0.0900
$0.0800
$0.0700
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
$30
$40
$50
$60
$70
$80
$90
Average Switchgrass Delivery Cost ($/ton)
Wind-High
Wind-Low
Coal
SWG COE ($/kWh):
COE for BioPower with No Incentives
COE for BioPower with SO2 Credit
COE for BioPower with both SO2 Credit & PTC

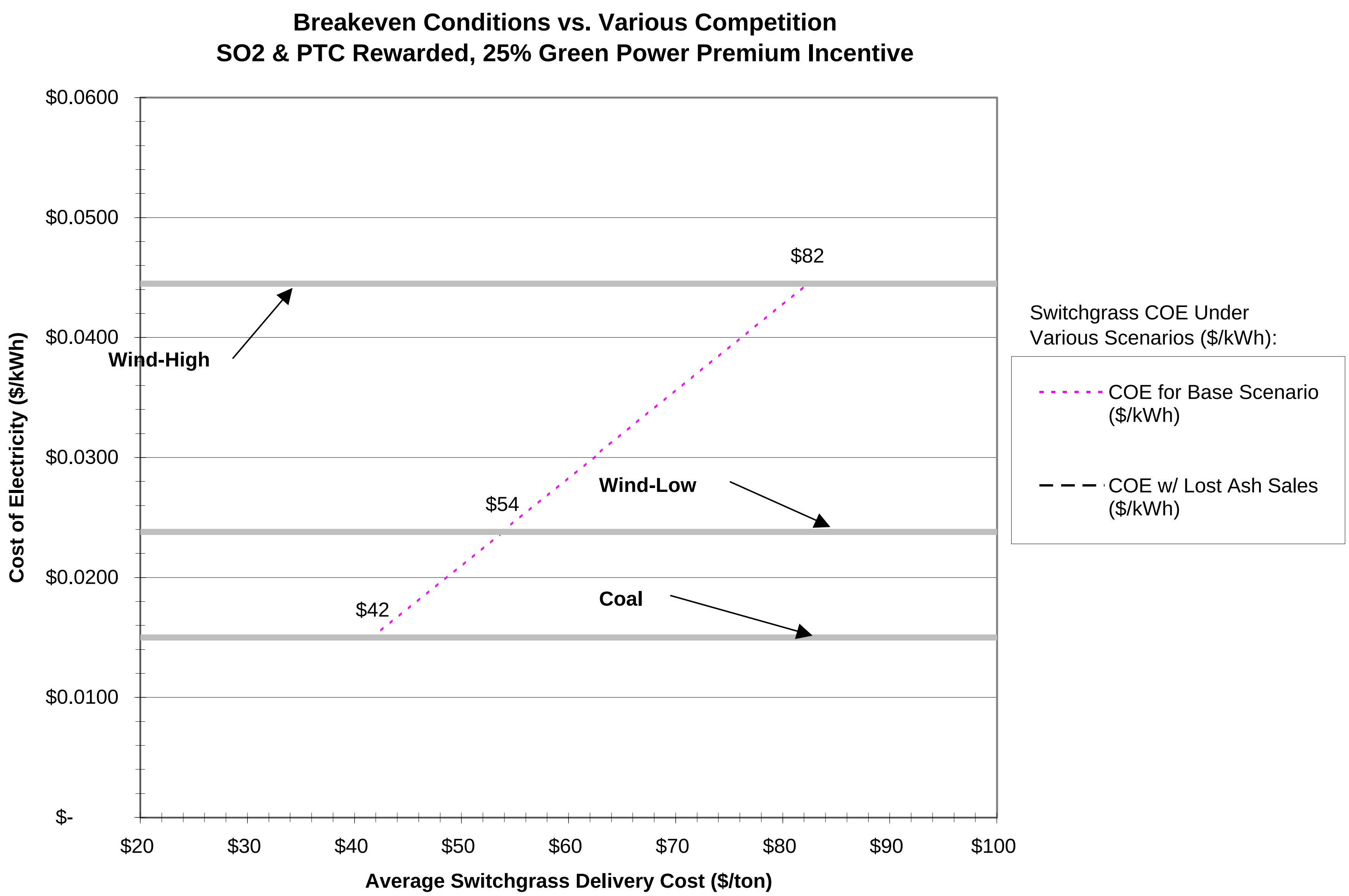

Breakeven Conditions vs. Various Competition
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
Cost of Electricity ($/kWh)
($20)
$0
$20
$40
$60
$80
$100
Average Switchgrass Delivery Cost ($/ton)
$56
$63
$82
$28
$34
$54
$9
$15
$35
Wind-High
Wind-Low
Coal
Switchgrass COE Under Various Scenarios ($/kWh):
COE w/ SO2 Credit and PTC w/o Lost Ash Sales
COE w/ SO2 Credit, PTC, and Lost Ash Sales
COE w/o Incentives and w/o Lost Ash Sales
COE w/ SO2 Credit and w/o Lost Ash Sales (values not shown)
COE w/o Incentives and Lost Ash Sales


Breakeven Conditions vs. Various Competition
SO2 Credit Rewarded
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
Cost of Electricity ($/kWh)
($10)
$0
$10
$20
$30
$40
$50
$60
Average Switchgrass Delivery Cost ($/ton)
$58
$29
$10
Wind-High
Wind-Low
Coal
Switchgrass COE Under
Various Scenarios ($/kWh):
COE for Base Scenario ($/kWh)
COE w/ Lost Ash Sales ($/kWh)

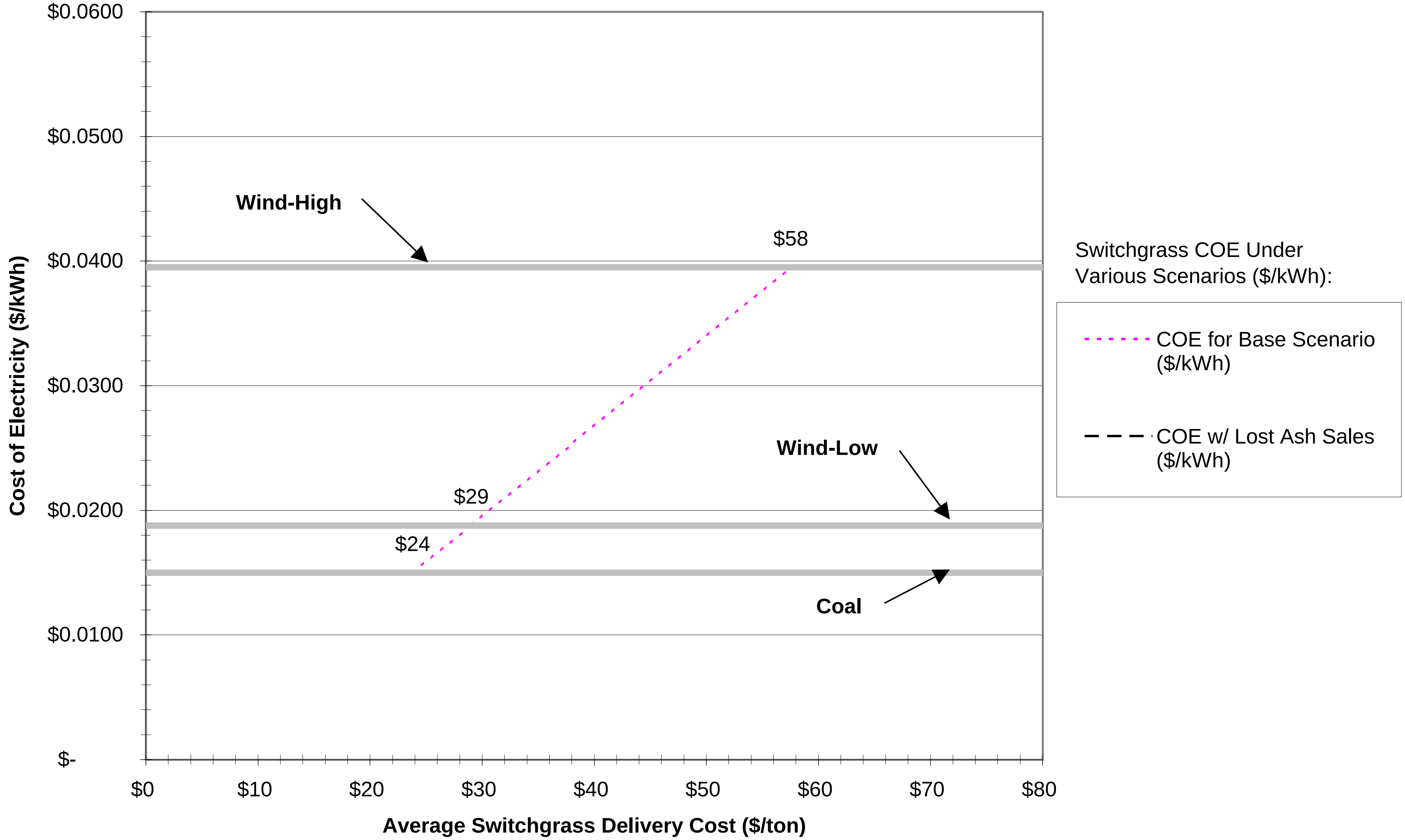

Breakeven Conditions vs. Various Competition
SO2 & PTC Rewarded
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
Cost of Electricity ($/kWh)
$10
$20
$30
$40
$50
$60
$70
$80
$90
Average Switchgrass Delivery Cost ($/ton)
$82
$54
$35
Wind-High
Wind-Low
Coal
Switchgrass COE Under Various Scenarios ($/kWh):
COE for Base Scenario ($/kWh)
COE w/ Lost Ash Sales ($/kWh)

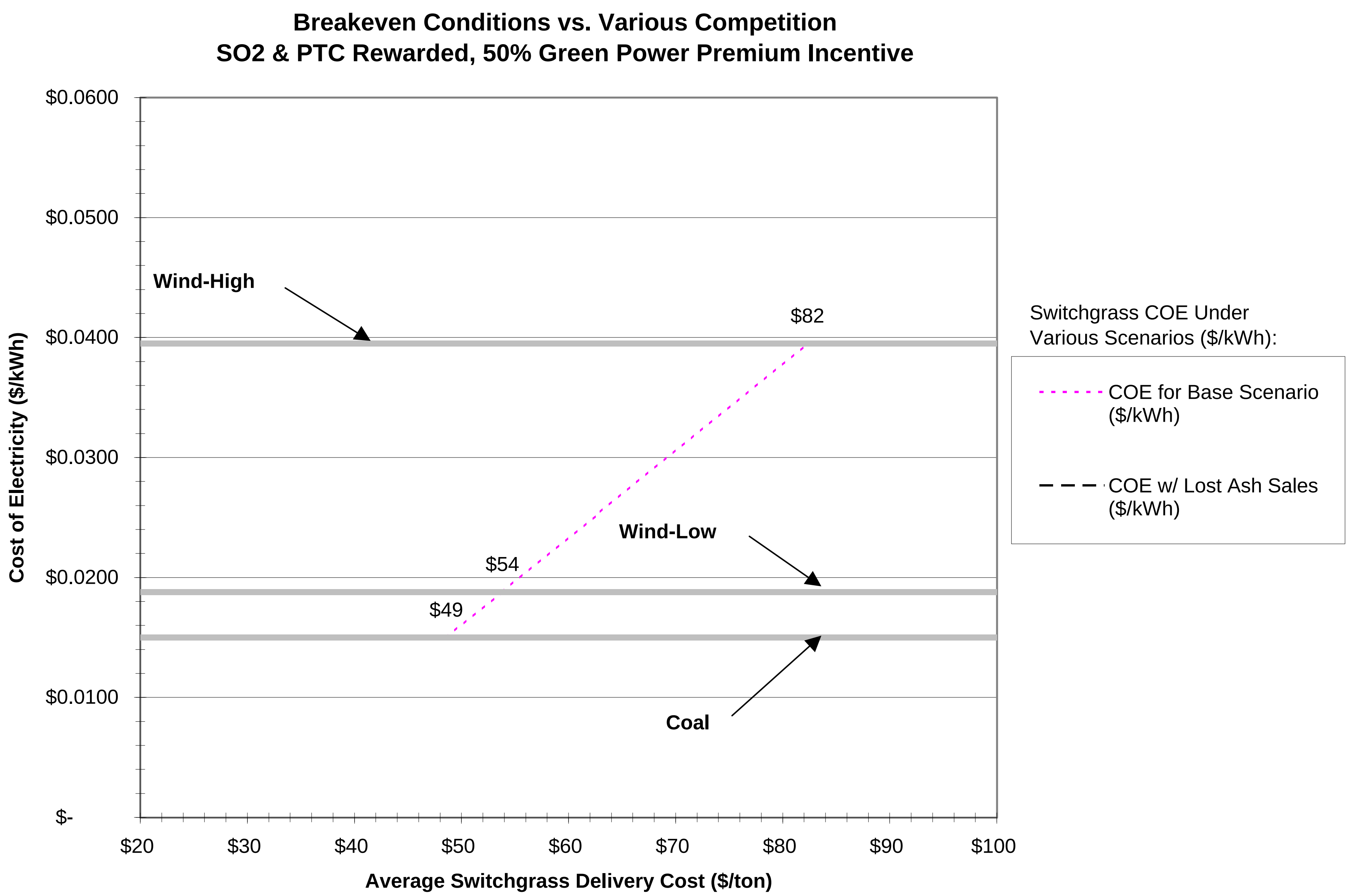
Breakeven Conditions vs. Various Competition
SO2 Credit Rewarded & 25% Green Power Premium Incentives



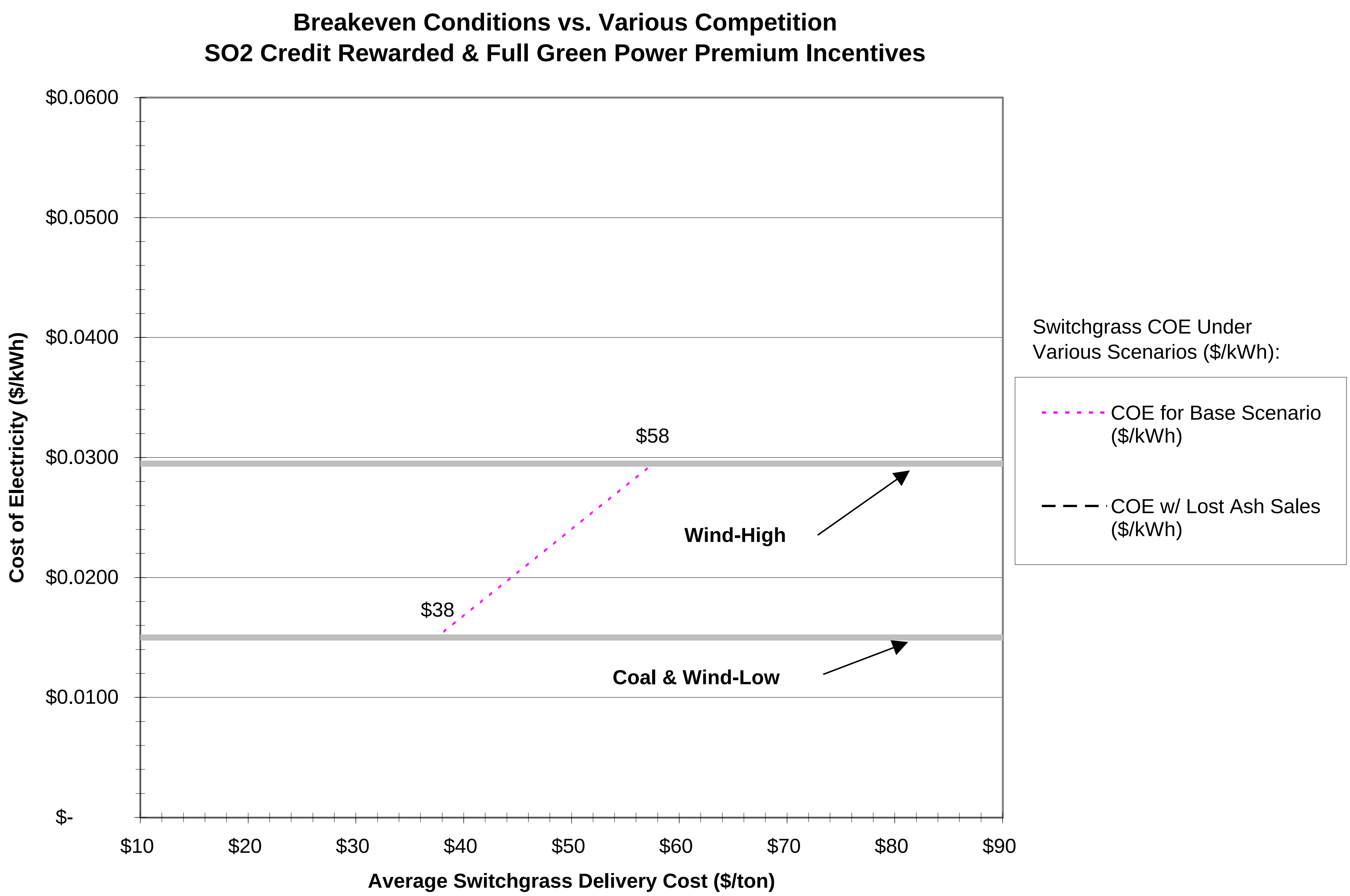

Breakeven Conditions vs. Various Competition
SO2 & PTC Rewarded, 25% Green Power Premium Incentive
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
Cost of Electricity ($/kWh)
$20
$30
$40
$50
$60
$70
$80
$90
$100
Average Switchgrass Delivery Cost ($/ton)
$82
$54
$42
Wind-High
Wind-Low
Coal
Switchgrass COE Under Various Scenarios ($/kWh):
COE for Base Scenario ($/kWh)
COE w/ Lost Ash Sales ($/kWh)

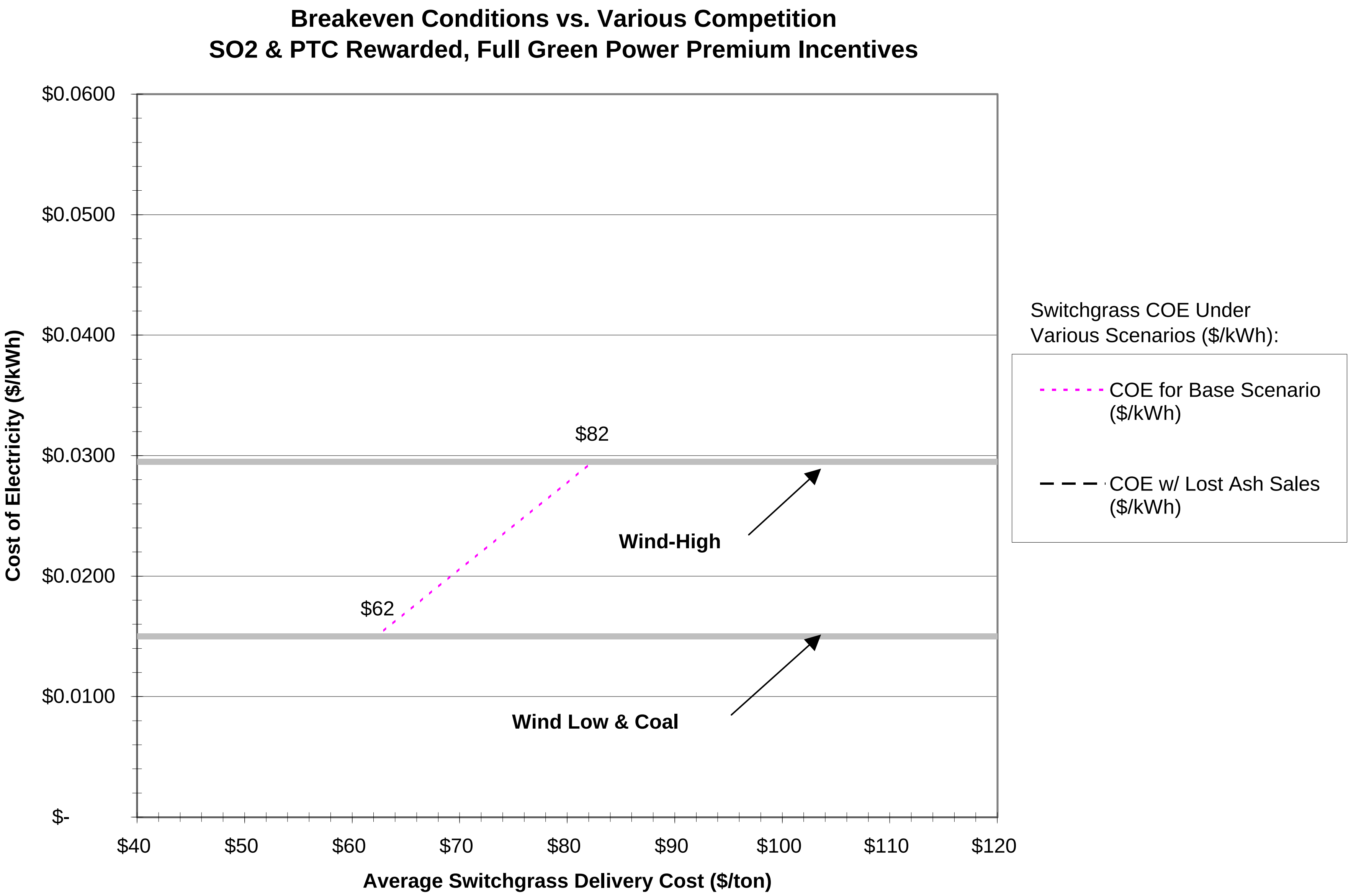
Breakeven Conditions vs. Various Competition
SO2 Credit Rewarded & 50% Green Power Premium Incentives





Breakeven Conditions vs. Various Competition
SO2 & PTC Rewarded, 50% Green Power Premium Incentive
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
Cost of Electricity ($/kWh)
$20
$30
$40
$50
$60
$70
$80
$90
$100
Average Switchgrass Delivery Cost ($/ton)
Wind-High
$82
Wind-Low
$54
$49
Coal
Switchgrass COE Under Various Scenarios ($/kWh):
COE for Base Scenario ($/kWh)
COE w/ Lost Ash Sales ($/kWh)


Breakeven Conditions vs. Various Competition
SO2 Credit Rewarded & Full Green Power Premium Incentives
Cost of Electricity ($/kWh)
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
$10
$20
$30
$40
$50
$60
$70
$80
$90
Average Switchgrass Delivery Cost ($/ton)
$58
$38
Wind-High
Coal & Wind-Low
Switchgrass COE Under Various Scenarios ($/kWh):
COE for Base Scenario ($/kWh)
COE w/ Lost Ash Sales ($/kWh)



Breakeven Conditions vs. Various Competition
SO2 & PTC Rewarded, Full Green Power Premium Incentives
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$-
Cost of Electricity ($/kWh)
$82
$62
Wind-High
Wind Low & Coal
$40
$50
$60
$70
$80
$90
$100
$110
$120
Average Switchgrass Delivery Cost ($/ton)
Switchgrass COE Under
Various Scenarios ($/kWh):
COE for Base Scenario
($/kWh)
COE w/ Lost Ash Sales
($/kWh)

APPENDIX G

Systems Benefit Charge Analysis

Alliant Energy Electricity Sales Information, by Consumer Class, 2000

	Residential				*Commercial*				*Industrial*				*Total / Overall*			
			Average Usage				Average Usage				Average Usage				Average Usage	
Utility	**Number of Customers**	**Total Sales (MWh)**	**kWh per Month**	**kWh per yr**	**Number of Customers**	**Total Sales (MWh)**	**kWh per Month**	**kWh per yr**	**Number of Customers**	**Total Sales (MWh)**	**kWh per Month**	**kWh per yr**	**Number of Customers**	**Total Sales (MWh)**	**kWh per Month**	**kWh per yr**
Iowa	*Iowa*				*Iowa*				*Iowa*				*Iowa*			
IES Utilities Inc.	294,540	2,742,536	776	9,311	50,296	2,700,655	4,475	53,695	712	5,052,968	591,405	7,096,865	345,548	10,496,159	2,531	30,375
Interstate Power Co.	98,782	879,640	742	8,905	16,127	426,878	2,206	26,470	827	2,827,816	284,947	3,419,366	115,736	4,134,334	2,977	35,722
Alliant Energy in Iowa	**393,322**	**3,622,176**	**767**	**9,209**	**66,423**	**3,127,533**	**3,924**	**47,085**	**1,539**	**7,880,784**	**426,726**	**5,120,717**	**461,284**	**14,630,493**	**2,643**	**31,717**
Wisconsin	*Wisconsin*				*Wisconsin*				*Wisconsin*				*Wisconsin*			
Wisconsin Power & Light Co.	352,311	3,089,512	731	8,769	48,274	1,992,506	3,440	41,275	919	4,580,721	415,372	4,984,462	401,504	9,662,739	2,006	24,066
Minnesota	*Minnesota*				*Minnesota*				*Minnesota*				*Minnesota*			
Interstate Power Co.	33,536	302,314	751	9,015	6,141	151,535	2,056	24,676	226	313,495	115,596	1,387,146	39,903	767,344	1,603	19,230
Illinois	*Illinois*				*Illinois*				*Illinois*				*Illinois*			
Interstate Power Co.	9,339	84,566	755	9,055	1,720	54,211	2,627	31,518	36	210,107	486,359	5,836,306	11,095	348,884	2,620	31,445
South Beloit WG&E	7,006	62,052	738	8,857	830	38,242	3,840	46,075	43	107,180	207,713	2,492,558	7,879	207,474	2,194	26,333
Overall Alliant Energy	**795,514**	**7,160,620**	**750**	**9,001**	**123,388**	**5,364,027**	**3,623**	**43,473**	**2,763**	**13,092,287**	**394,869**	**4,738,432**	**862,788**	**24,293,232**	**2,346**	**28,157**

SOURCE: Energy Information Adminstration, *Electric Sales and Revenue 2000*, DOE/EIA-0540(00), U.S. Department of Energy, Washington, DC. January, 2002. (Year 2000 data in table above)

	Residential	Commercial	Industrial	Total / Overall
CVBP vs. Iowa kWhs	7.6%	8.8%	3.5%	1.9%
CVBP vs. Total Alliant kWhs	3.8%	5.1%	2.1%	1.1%

Equiv. premiums if rate-based for all Alliant Customers

Incentive Considered	Per Res. Cust. Premium ($/month)	Per Res. Cust. Premium ($/yr)	**Total $/yr**	% of Total Alliant Electricity Revenue	Iowa Only (c/kWh rate increase)	Total Alliant (c/kWh rate increase)	Iowa Only ($/kWh rate increase)	**Total Alliant ($/kWh rate increase)**	Fraction of AEP Rider (Iowa only)	Fraction of GS Energy Efficiency Rider (Iowa only)	**Fraction of AEP Rider (Total Alliant)**	Fraction of GS Energy Efficiency Rider (Total Alliant)	**Fraction of Total Alliant Wind Gen.**
SBC Equivalent to support CVBP project with no other incentives (except SO2 credits), delivered SWG price = $52/ton	0.55	6.59	**8,200,000**		0.021111		0.000211		16.1%	6.4%			
Total Alliant Premium @ 2 c/kWh	15.00	180	**5,500,000**	0.4%	0.037593	0.02264	0.000376	**0.000226**	28.7%	11.4%	**17.3%**	6.9%	
Total Alliant Premium @ 1 c/kWh	7.50	90	**2,750,000**	0.2%	0.018796	0.01132	0.000188	**0.000113**	14.4%	5.7%	**8.7%**	3.4%	
Total Alliant Premium @ 0.5 c/kWh	3.75	45	**1,375,000**	0.1%	0.009398	0.00566	0.000094	**0.000057**	7.2%	2.8%	**4.3%**	1.7%	

CVBP Annual Generation:	275,000	MWh/yr
CVBP Generation vs. Estimated Total Alliant Wind Generation:	43%	
Total 1999 Iowa Electric Generation	38,842,106	MWh/yr
Total 2000 Iowa Res. Electric Customers	1,243,488	

Electricity Revenues	**Thousand $**
Residential	567,283
Commercial	349,019
Industrial	501,155
Total	**1,417,457**

SOURCE: Alliant Energy 2001 Annual Report (Year 2000 Data in table above)

Estimated Alliant Wind Power Capacity & Generation

Site	**Alliant MW**	**Est. Gen. (MWh/yr)**
Cerro Gordo	42	117,734
Storm Lake	80	268,601
Top of Iowa	80	225,000
Montfort	4.5	12,614
Allenton	4.5	12,614
Total	**211**	**636,564**

SOURCE: Alliant Energy Web Site, *Renewable Energy - Wind*, http://www.alliantenergy.com/about/environment/renewable/wind.htm, accessed on July 17, 2002.

Existing IES Energy Efficiency Cost Recovery Rider (Rider No. 17)

Rate Class	**$/kWh rider**
Residential	0.0039
General Service	0.0033
Large GS	0.0013

Alternate Energy Production Clause Rider (Rider No. 5): 0.00131 $/kWh (average for Nov. 2000 to Oct. 2001)

APPENDIX H

Estimate of Cumulative Production Tax Credit Costs for Wind and Closed-Loop Biomass

Comparison of Wind and Biomass Tax Credits Claimed Under Section 45 Tax Credit
(Assuming credit is modified to allow cofiring energy crops from USDA CRP Pilot Projects)

Summary:

Peak Single-Year Qualified Biomass Capacity:	70 MW
Peak Single-Year Qualified Wind Capacity :	2,849 MW
Chariton Valley Biomass Capacity:	35 MW
Pre-2002 Credit Value (Wind):	$199 million
Pre-2002 Credit Value (Total Biomass):	$0 million
Pre-2002 Credit Value (Chariton Valley Biomass):	$0 million
Lifetime Credit Value (Wind): (neglects installs after 2001)	$1,144 million
Lifetime Credit Value (Total Biomass):	$87 million
Lifetime Credit Value (Chariton Valley Biomass):	$44 million
Lifetime Credit Value as % of Wind (Total Biomass):	8% million
Lifetime Credit Value as % of Wind (CV Biomass):	4% million
Maximum Single-Year Credit Value (Wind): (neglects installs after 2001)	$105 million
Maximum Single-Year Credit Value (Total Biomass):	$10 million
Maximum Single-Year Credit Value (CV Biomass):	$5 million

Estimated Qualified Generation and Federal Tax Credits for Wind Since 1992

Year	Wind-Powered Generation (Billion kWh)	Gross Domestic Product Implicit Price Deflator	Value of Production Tax Credit ($/kWh)	Total Estimated Tax Credit (Billion $)	Total Estimated Tax Credit (Million $)
Estimated Generation and Tax Credits Prior to 2002					
1992	0.0	91.84	$0.015	$0.00	$0.0
1993	0.1	94.05	$0.015	$0.00	$2.1
1994	0.6	96.01	$0.016	$0.01	$8.9
1995	0.3	98.10	$0.016	$0.00	$4.5
1996	0.5	100.00	$0.016	$0.01	$8.1
1997	0.3	101.95	$0.017	$0.01	$5.6
1998	0.1	103.20	$0.017	$0.00	$1.7
1999	1.3	104.65	$0.017	$0.02	$21.4
2000	2.4	107.04	$0.017	$0.04	$41.7
2001	5.9	109.48	$0.018	$0.11	$105.2
Sub-Totals To Date	**11.4**	- - - - - -	- - - - - -	**$0.20**	**$199.1**
Estimated Future Generation and Tax Credits (Assuming NO NEW WIND INSTALLATIONS after 2001)					
2002	5.9	111.98	$0.018	$0.11	$107.6
2003	5.7	114.54	$0.019	$0.11	$107.5
2004	5.3	117.16	$0.019	$0.10	$101.8
2005	5.6	119.83	$0.020	$0.11	$109.7
2006	5.4	122.57	$0.020	$0.11	$107.9
2007	5.5	125.37	$0.020	$0.11	$113.6
2008	5.8	128.23	$0.021	$0.12	$121.1
2009	4.6	131.16	$0.021	$0.10	$99.2
2010	3.5	134.16	$0.022	$0.08	$76.7
Grand Total	**58.8**	- - - - - -	- - - - - -	**$1.14**	**$1,144.3**

NOTES:
1) Future year numbers for the tax credit value ($/kWh) assume the price deflator rises at the same rate it did between 1999 and 2000.
2) Wind generation data was obtained from the Energy Information Administration and the American Wind Energy Association.
3) Generation from all wind projects installed before 1992 is assumed not to qualify for any tax credits over the life of the projects.

Estimated Federal Tax Credits for Cofiring Energy Crops from USDA CRP Pilot Projects

Year	Biomass-Powered Generation (Billion kWh)	Value of Production Tax Credit ($/kWh)	Total Estimated Tax Credit (Billion $)	Total Estimated Tax Credit (Million $)	Qualified Biomass Capacity (MW)
2002	0.43	$0.018	$0.01	$7.85	70
2003	0.43	$0.019	$0.01	$8.03	70
2004	0.43	$0.019	$0.01	$8.21	70
2005	0.43	$0.020	$0.01	$8.40	70
2006	0.43	$0.020	$0.01	$8.59	70
2007	0.43	$0.020	$0.01	$8.79	70
2008	0.43	$0.021	$0.01	$8.99	70
2009	0.43	$0.021	$0.01	$9.20	70
2010	0.43	$0.022	$0.01	$9.41	70
2011	0.43	$0.022	$0.01	$9.62	70
Grand Total	**4.29**	**- - - - - -**	**$0.09**	**$87.09**	- - - - - -

NOTE:
Credits for closed-loop biomass cofiring projects would probably not begin until 2005.

Estimated Federal Tax Credits for Chariton Valley Biomass Project Only

Year	Biomass-Powered Generation (Billion kWh)	Value of Production Tax Credit ($/kWh)	Total Estimated Tax Credit (Billion $)	Total Estimated Tax Credit (Million $)	Qualified Biomass Capacity (MW)
2002	0.21	$0.018	$0.004	$3.93	35
2003	0.21	$0.019	$0.004	$4.02	35
2004	0.21	$0.019	$0.004	$4.11	35
2005	0.21	$0.020	$0.004	$4.20	35
2006	0.21	$0.020	$0.004	$4.30	35
2007	0.21	$0.020	$0.004	$4.39	35
2008	0.21	$0.021	$0.004	$4.50	35
2009	0.21	$0.021	$0.005	$4.60	35
2010	0.21	$0.022	$0.005	$4.70	35
2011	0.21	$0.022	$0.005	$4.81	35
Grand Total	**2.15**	**- - - - - -**	**$0.044**	**$43.54**	**- - - - - -**

NOTE:
Credits for the Chariton Valley Project would probably not begin until 2005.

APPENDIX I

Nebraska / Iowa / SW Minnesota Hay Auction Summary

SC_GR310
Kearney, NE Thu, Jul 18, 2002 USDA NE Dept of Ag Market News

Nebraska/Iowa/SW Minnesota Hay Summary - Week Ending July 19, 2002

All sales FOB point of origin per ton unless otherwise stated.

NEBRASKA:

Hay prices firm to 5.00 per ton higher, instances 10.00 higher. Alfalfa, ground and delivered to feedlots firm. Good inquiry and demand noted as the dry weather conditions continue. Out of state inquiry very good. Alfalfa pellets firm to 5.00 higher than last week.

Northeast Nebraska: Alfalfa: Good to Premium 3X3X8 and large square bales 110.00, few 100.00. Good to Premium large round bales 70.00-80.00; Large round bales, ground and delivered to feedlots 90.00. Good small square bales prairie hay 95.00-100.00; Good to Premium large round bales prairie hay 80.00-85.00, instances 90.00. Oat straw in large round bales 40.00 per ton. Dehydrated alfalfa pellets, 17 percent protein, 135.00-138.00, instances 140.00. Suncured not tested.

Platte Valley of Nebraska: Lexington/Cozad: Alfalfa: Good to Premium 3X3X8 square bales and large square bales 100.00; Good to Premium large round bales 70.00-80.00, few 90.00. Large round bales, ground and delivered to feedlots 90.00-95.00, few 100.00. Second cutting alfalfa standing in the field 50.00 per ton. Dehydrated alfalfa pellets, 17 percent protein, mostly 135.00, instances 140.00. Suncured not tested.

IOWA:

Northeast IA: Fort Atkinson, IA Hay Auction. (07-17-2002) 74 loads, Hay prices 10.00-20.00 per ton Higher. Alfalfa: Fair to Good small square bales 85.00-95.00; Fair small square bales 75.00-85.00; Low to Fair 60.00-70.00. Good to Premium 3X3X8 square bales 90.00-110.00; Fair to Good 3X3X8 square bales 60.00-90.00; Fair 3X3X8 square bales 50.00-60.00. Good to Premium large round bales 70.00-85.00; Fair to Good large round bales 50.00-70.00; Fair 40.00-60.00.

Northwest IA: Maurice, IA Hay Auction (07-16-2002) 18 loads, 207 tons. Alcester, SD Hay Auction closed for the season. Hay prices near steady. Demand fair to good. Alfalfa: Good large square bales 80.00-87.50. Premium to Supreme large round bales 90.00-95.00; Good to Premium 82.50-90.00. Grass: Good to Premium large square bales 80.00-85.00. Brome in large round bales 75.00-80.00.

South-central IA (Private treaty): Hay prices fully steady. Good inquiry. Alfalfa: Good to Premium small square bales horse hay mostly 110.00-120.00; Good 90.00-100.00. Good large round bales 65.00-75.00, Fair to Good 55.00-65.00. Alfalfa/grass mix: Premium small square bales 90.00-110.00; Good to Premium large round bales 65.00-70.00.

MINNESOTA

Southwest MN: Pipestone, MN. Weekly Hay Auction (07-16-2002). 33 Loads, 172 tons. Alfalfa: Good small squares 100.00-107.50; Fair to Good small square bales 85.00-100.00; Fair 77.50-85.00. Good large square bales 92.50; Supreme large round bales 90.00-100.00; Good to Premium large round bales 67.50-90.00. Alfalfa/Grass mix: Good small square bales 80.00-82.50; Premium large round bales 82.50. Grass: Good to Premium small square bales 90.00-100.00; Fair to Good small square bales 70.00-90.00; Fair 65.00-70.00; Good to Premium large round bales 70.00-85.00; Fair to Good large round bales 60.00-70.00; Fair 47.50-60.00. Straw in small square bales 1.50 per bale.

Detailed Quotations

	Iowa	Nebraska
Alfalfa		
Small and Large squares		
Supreme	-------------	-------------
Premium	90.00-120.00	100.00-110.00
Good	80.00-110.00	100.00-110.00
Fair	50.00- 85.00	------------
Large Rounds		
Supreme	90.00- 95.00	------------
Premium	75.00- 90.00	80.00- 90.00
Good	65.00- 80.00	70.00- 80.00
Fair	40.00- 70.00	------------
Grass Hay		
Small and Large Squares		
Premium	80.00- 85.00	------------
Good	80.00	95.00-100.00
Fair	------------	------------
Large Rounds		
Premium	------------	80.00- 90.00
Good	------------	80.00- 85.00
Fair	------------	------------
Pellets		
Dehydrated Alfalfa 17pct		135.00-140.00
Suncured Alfalfa 17pct		--------------

Hay Quality Designations:

Relative Feed Value: (RFV)

180 or higher	Supreme
150-180	Premium
125-150	Good
100-125	Fair

Source: USDA NE Dept of Ag Market News, Kearney, NE (308) 237-7579
24 Hour Recorded Market Reports - (308) 234-1059
Internet site: www.ams.usda.gov/mnreports/sc_gr310.txt

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APPENDIX J

Effect of Crop Yield, Land Rent, and CRP Pilot Program on Delivered Biomass Costs

Yield (ton/acre)	Land Charge ($/acre)	Storage Cost ($/ton)	CRP Land Farming (Yes / No)	Delivered Fuel Price ($/ton)
1.5	$25	$7	Yes	**$90**
			No	**$110**
		$14	Yes	**$97**
			No	**$117**
	$50	$7	Yes	**$92**
			No	**$127**
		$14	Yes	**$99**
			No	**$134**
	$75	$7	Yes	**$95**
			No	**$145**
		$14	Yes	**$102**
			No	**$152**
	$100	$7	Yes	**$97**
			No	**$162**
		$14	Yes	**$104**
			No	**$169**
3	$25	$7	Yes	**$65**
			No	**$75**
		$14	Yes	**$72**
			No	**$82**
	$50	$7	Yes	**$66**
			No	**$84**
		$14	Yes	**$73**
			No	**$91**
	$75	$7	Yes	**$68**
			No	**$93**
		$14	Yes	**$75**
			No	**$100**
	$100	$7	Yes	**$69**
			No	**$102**
		$14	Yes	**$76**
			No	**$109**
4	$25	$7	Yes	**$59**
			No	**$67**
		$14	Yes	**$66**
			No	**$74**
	$50	$7	Yes	**$60**
			No	**$73**
		$14	Yes	**$67**
			No	**$80**
	$75	$7	Yes	**$60**
			No	**$79**
		$14	Yes	**$67**
			No	**$86**
	$100	$7	Yes	**$61**
			No	**$85**
		$14	Yes	**$68**
			No	**$92**
6	$25	$7	Yes	**$52**
			No	**$57**
		$14	Yes	**$59**
			No	**$64**
	$50	$7	Yes	**$53**
			No	**$62**
		$14	Yes	**$60**
			No	**$69**
	$75	$7	Yes	**$54**
			No	**$67**
		$14	Yes	**$61**
			No	**$74**
	$100	$7	Yes	**$54**
			No	**$70**
		$14	Yes	**$61**
			No	**$77**

With CRP Rental Payment Sorted by Yield

Yield	Land Charge	Storage Cost	Delivery Fuel Price
1.5	25	7	90
1.5	50	7	92
1.5	75	7	95
1.5	100	7	97
1.5	25	14	97
1.5	50	14	99
1.5	75	14	102
1.5	100	14	104
3	25	7	65
3	50	7	66
3	75	7	68
3	100	7	69
3	25	14	72
3	50	14	73
3	75	14	75
3	100	14	76
4	25	7	59
4	50	7	60
4	75	7	60
4	100	7	61
4	25	14	66
4	50	14	67
4	75	14	67
4	100	14	68
6	25	7	52
6	50	7	53
6	75	7	54
6	100	7	54
6	25	14	59
6	50	14	60
6	75	14	61
6	100	14	61

With CRP Rental Payment Sorted by Land Charge

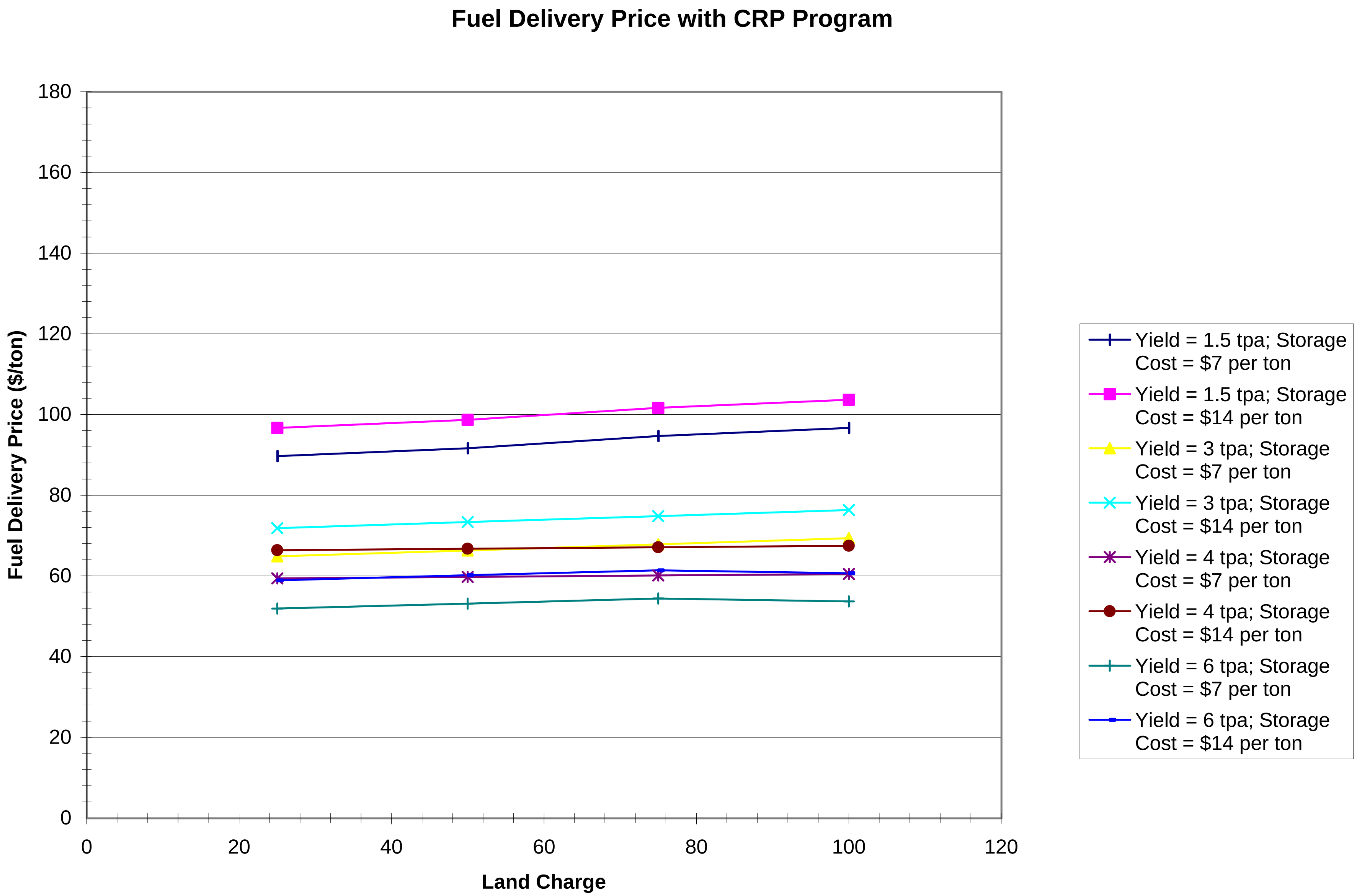
Yield	Land Charge	Storage Cost	Delivery Fuel Price
1.5	$25	$7	$90
3	$25	$7	$65
4	$25	$7	$59
6	$25	$7	$52
1.5	$50	$7	$92
3	$50	$7	$66
4	$50	$7	$60
6	$50	$7	$53
1.5	$75	$7	$95
3	$75	$7	$68
4	$75	$7	$60
6	$75	$7	$54
1.5	$100	$7	$97
3	$100	$7	$69
4	$100	$7	$61
6	$100	$7	$54
1.5	$25	$14	$97
3	$25	$14	$72
4	$25	$14	$66
6	$25	$14	$59
1.5	$50	$14	$99
3	$50	$14	$73
4	$50	$14	$67
6	$50	$14	$60
1.5	$75	$14	$102
3	$75	$14	$75
4	$75	$14	$67
6	$75	$14	$61
1.5	$100	$14	$104
3	$100	$14	$76
4	$100	$14	$68
6	$100	$14	$61

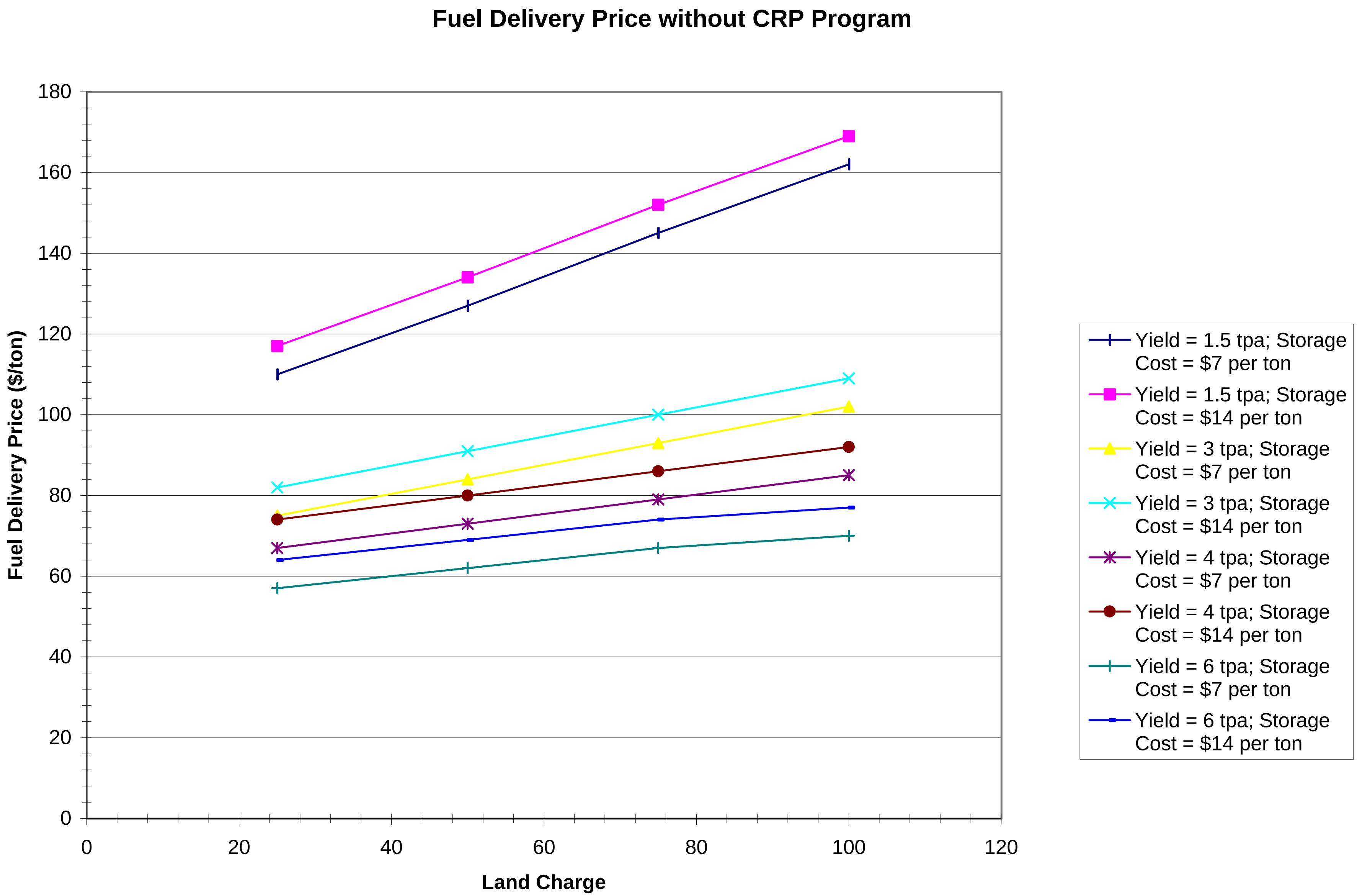
Without CRP Rental Payment

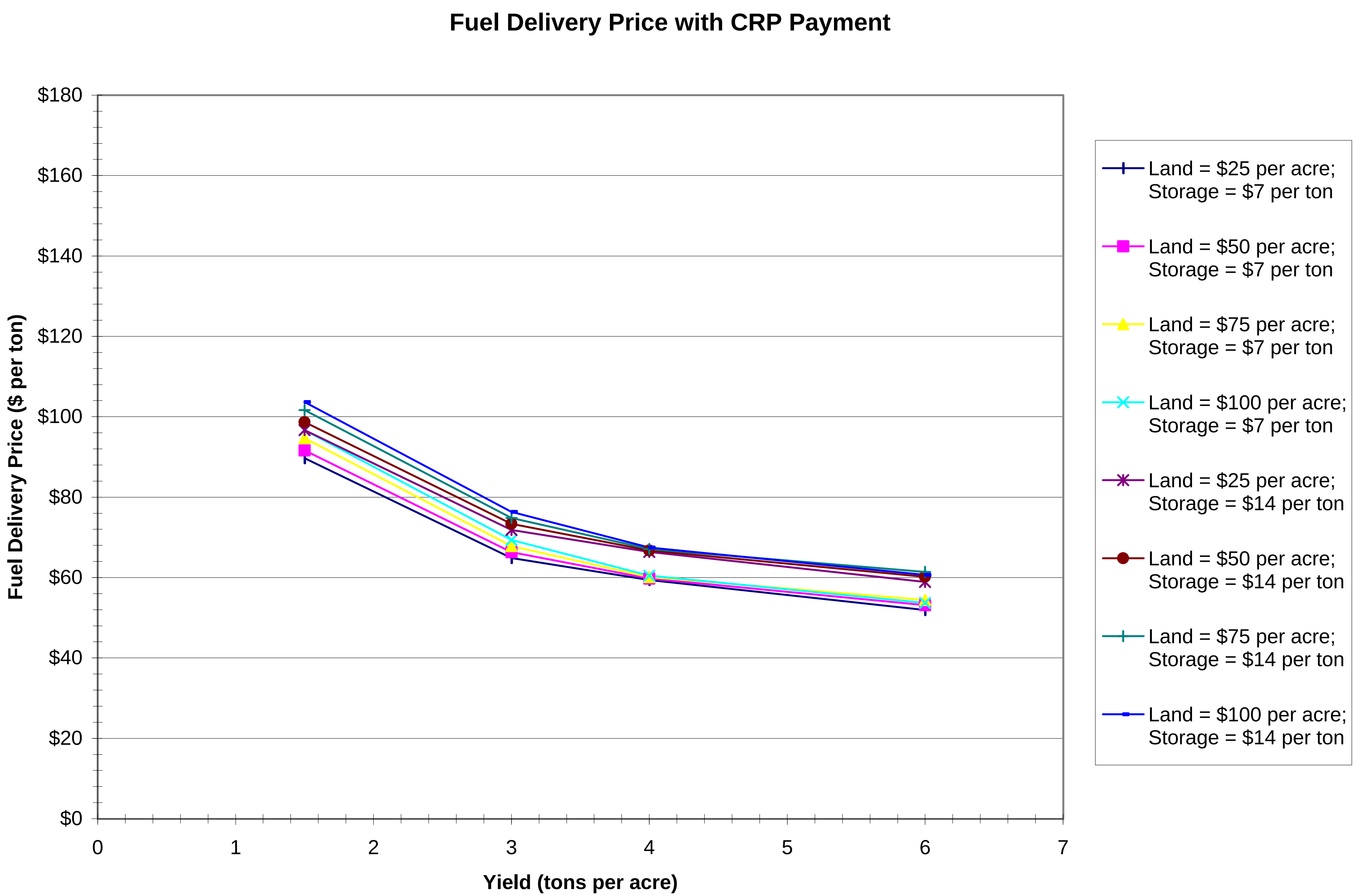
Yield	Land Charge	Storage Cost	Delivery Fuel Price
1.5	25	7	110
1.5	50	7	127
1.5	75	7	145
1.5	100	7	162
1.5	25	14	117
1.5	50	14	134
1.5	75	14	152
1.5	100	14	169
3	25	7	75
3	50	7	84
3	75	7	93
3	100	7	102
3	25	14	82
3	50	14	91
3	75	14	100
3	100	14	109
4	25	7	67
4	50	7	73
4	75	7	79
4	100	7	85
4	25	14	74
4	50	14	80
4	75	14	86
4	100	14	92
6	25	7	57
6	50	7	62
6	75	7	67
6	100	7	70
6	25	14	64
6	50	14	69
6	75	14	74
6	100	14	77

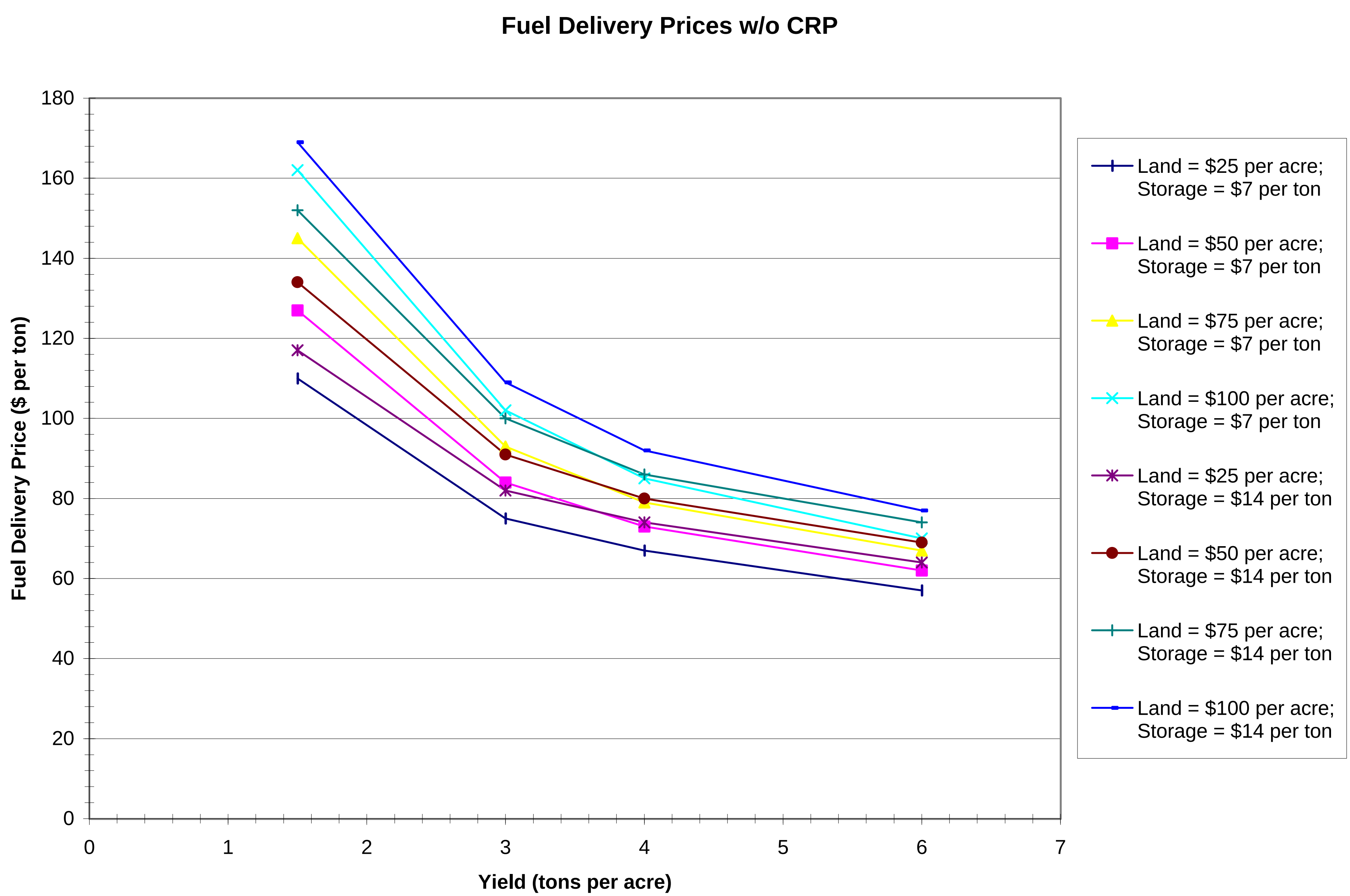
Without CRP Rental Payment

Yield	Land Charge	Storage Cost	Delivery Fuel Price
1.5	25	7	110
3	25	7	75
4	25	7	67
6	25	7	57
1.5	50	7	127
3	50	7	84
4	50	7	73
6	50	7	62
1.5	75	7	145
3	75	7	93
4	75	7	79
6	75	7	67
1.5	100	7	162
3	100	7	102
4	100	7	85
6	100	7	70
1.5	25	14	117
3	25	14	82
4	25	14	74
6	25	14	64
1.5	50	14	134
3	50	14	91
4	50	14	80
6	50	14	69
1.5	75	14	152
3	75	14	100
4	75	14	86
6	75	14	74
1.5	100	14	169
3	100	14	109
4	100	14	92
6	100	14	77


Fuel Delivery Price with CRP Program
Fuel Delivery Price ($/ton)
180
160
140
120
100
80
60
40
20
0
0
20
40
60
80
100
120
Land Charge
Yield = 1.5 tpa; Storage Cost = $7 per ton
Yield = 1.5 tpa; Storage Cost = $14 per ton
Yield = 3 tpa; Storage Cost = $7 per ton
Yield = 3 tpa; Storage Cost = $14 per ton
Yield = 4 tpa; Storage Cost = $7 per ton
Yield = 4 tpa; Storage Cost = $14 per ton
Yield = 6 tpa; Storage Cost = $7 per ton
Yield = 6 tpa; Storage Cost = $14 per ton


Fuel Delivery Price without CRP Program
Fuel Delivery Price ($/ton)
180
160
140
120
100
80
60
40
20
0
0
20
40
60
80
100
120
Land Charge
Yield = 1.5 tpa; Storage Cost = $7 per ton
Yield = 1.5 tpa; Storage Cost = $14 per ton
Yield = 3 tpa; Storage Cost = $7 per ton
Yield = 3 tpa; Storage Cost = $14 per ton
Yield = 4 tpa; Storage Cost = $7 per ton
Yield = 4 tpa; Storage Cost = $14 per ton
Yield = 6 tpa; Storage Cost = $7 per ton
Yield = 6 tpa; Storage Cost = $14 per ton


Fuel Delivery Price with CRP Payment
Fuel Delivery Price ($ per ton)
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
1
2
3
4
5
6
7
Yield (tons per acre)
Land = $25 per acre; Storage = $7 per ton
Land = $50 per acre; Storage = $7 per ton
Land = $75 per acre; Storage = $7 per ton
Land = $100 per acre; Storage = $7 per ton
Land = $25 per acre; Storage = $14 per ton
Land = $50 per acre; Storage = $14 per ton
Land = $75 per acre; Storage = $14 per ton
Land = $100 per acre; Storage = $14 per ton



Fuel Delivery Prices w/o CRP
Fuel Delivery Price ($ per ton)
180
160
140
120
100
80
60
40
20
0
0
1
2
3
4
5
6
7
Yield (tons per acre)
Land = $25 per acre; Storage = $7 per ton
Land = $50 per acre; Storage = $7 per ton
Land = $75 per acre; Storage = $7 per ton
Land = $100 per acre; Storage = $7 per ton
Land = $25 per acre; Storage = $14 per ton
Land = $50 per acre; Storage = $14 per ton
Land = $75 per acre; Storage = $14 per ton
Land = $100 per acre; Storage = $14 per ton