BBI INTERNATIONAL CONSULTING

April 26, 2004

Frank Kirschenheiter
Project Coordinator
Red Tail Energy, LLC
P.O. Box 11
Richardton, ND 58652

Dear Frank:

Thanks you for allowing BBI to update the Richardton, ND ethanol feasibility study to reflect Red Trail Energy's current business plan. We concur with the financial projections in your business plan and judge the Red Trail Energy project as described in the business plan and in the BBI feasibility study to be a very good project.

We had previously discussed the feasibility study that BBI recently completed for the North Dakota Lignite Research Council. I wanted to compare that study to the Red Trail Energy feasibility study we just completed. The table on the following page shows the major differences between the two studies. Briefly, these differences are:

- Ethanol nameplate capacity
- Capital cost per gallon and total project cost
- % equity used in the financial analysis

Because of the different assumptions used in the two studies, it is not possible to directly compare the results. The Capital Cost per Gallon is by far the most important difference in the two studies and has the greatest impact on the projected returns. In the study for the ND Lignite Research Council, we used industry average capital costs for the ethanol plant and budgetary quotes for the lignite-fired co-generation facility. Red Trail Energy's Capital Cost per Gallon ($1.61) is significantly less than the figure used for the Lignite Research Council study ($2.11).

If we change the Research Council study Nameplate capacity to 50 million gallons per year and hold the capital cost constant (right hand column in the table), the resulting Capital Cost per Gallon is nearly identical to that for Red Trail Energy. The projected returns are also nearly the same. BBI's conclusion is that the lower capital cost and increased nameplate capacity of the Red Trail Energy project makes the project viable. If you have any questions, please contact me.

Sincerely,

Mark Yancey

Mark Yancey
Director

BBI International Consulting
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Comparison of the Red Trail Energy Feasibility Study to the ND Lignite Research Council Feasibility Study
both studies prepared by BBI International

	Red Trail Energy Feasibility Study	ND Lignite Council Feasibility Study Richardton Site	ND Lignite Council Feasibility Study @ 50 MMGPY
Ethanol Plant Nameplate Capacity	50,000,000	40,000,000	50,000,000
Ethanol Plant Cost including contingency	$45,000,000	$45,000,000	$45,000,000
Lignite-fired Cogeneration Cost	$19,200,000	$26,300,000	$26,300,000
Rail Improvements	$2,300,000	$2,250,000	$2,250,000
Owner's Costs	$14,045,000	$10,866,000	$10,866,000
Total Project Capital Cost	$80,545,000	$84,416,000	$84,416,000
Capital Cost per Gallon	$1.61	$2.11	$1.69
% Equity in Report	45%	100%	NA
Return on Investment (ROI) in Report	27.6%	NA	NA
Internal Rate of Return (IRR) in Report	NA	10.8%	NA
Return on Investment (see notes below)			
ROI with 45% Equity	27.0%	17.4%	29.5%
ROI with 100% Equity	13.6%	9.3%	14.7%
Other Assumptions Used in the Respective Studies			
Delivered Corn Price, $/bu	2.44	2.43	2.43
Ethanol Price, $/gal	1.27	1.27	1.27
Ethanol Shipping, $/gal	0.107	0.10	0.10
Ethanol Marketing Fee, $/gal	0.01	0.01	0.01
Net Ethanol Price, $/gal	1.153	1.160	1.160
Lignite Use, tons/year	132,000	128,500	128,500
Lignite Price at Mine, $/ton	11.00	11.00	11.00
Lignite Transportation, $/ton	6.00	6.00	6.00
Delivered Lignite Price, $/ton	17.00	17.00	17.00
# of Employees	40	51	51

Notes:
Changes made to the ND Lignite Research Council Study to match the Red Trail Energy Study:
1. Removed inflation from all cost and revenue inputs
2. Changed construction and startup to 12 months (same as RTE model)
3. Added CCC payments to the ND Lignite Research Council Study
4. Changed Ethanol Production Increase Over Nameplate to 3%/year for years 2-5
5. Changed ND Lignite Research Council Study debt to 7% interest for 7 years
6. Removed the $500,000 grant from both models

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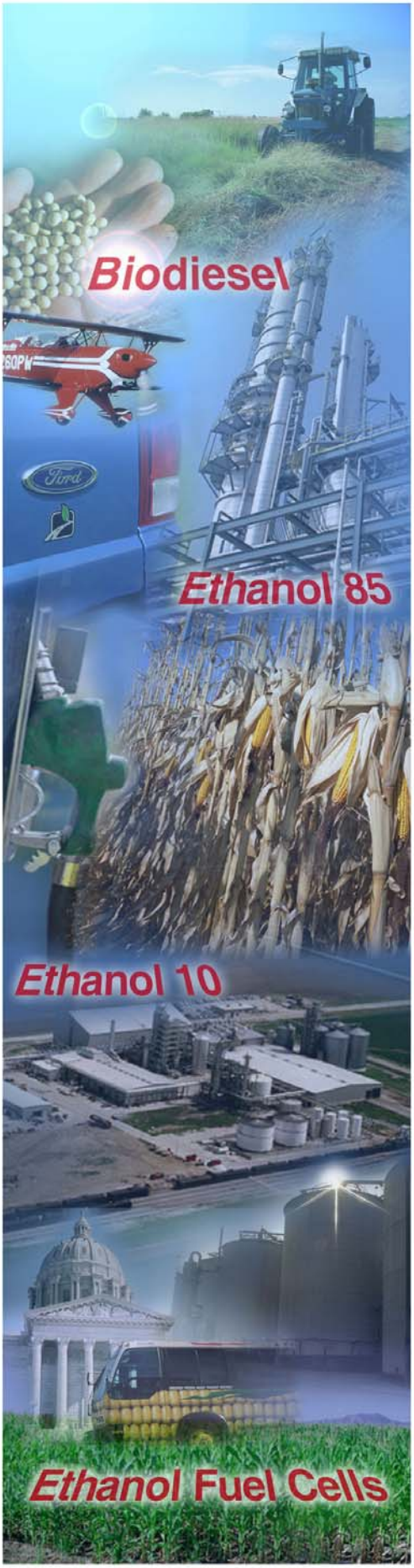

Feasibility of Lignite-Powered Ethanol Plants in North Dakota

Prepared for:

Lignite Research Council
P.O. Box 2277
1016 E. Owens Ave.
Bismarck, ND 58502

April 15, 2004

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VALUE ADDED AGRICULTURE

The growth of the ethanol industry presents an opportunity to add value to North Dakota corn and barley, create high paying jobs and produce significant local economic development in the region where ethanol plants are built.

The Lignite Research Council has contracted with BBI International to complete a study that will assess the feasibility of using lignite coal as a substitute for natural gas as the primary energy source for a dry-mill ethanol plant. The feasibility study will assess the various aspects of the project and will be used as a tool to judge the overall viability of the proposed project. Based on the results of the report, project developers will be able to decide whether or not to proceed with the development of lignite power ethanol plants in the state.

BBI is an independent consulting firm with no vested interest in the proposed project. The information detailed in this report reflects, to the best of our ability, a true and accurate evaluation of the current ethanol industry, applicable markets, and the feasibility of the project.

Michael D. Bryan
President
BBI International

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I. EXECUTIVE SUMMARY

Introduction

The Industrial Commission of North Dakota (NDIC) has retained BBI International to conduct a feasibility study to determine the viability of "lignite-powered" ethanol plants in North Dakota. The purpose of this feasibility study is to characterize the potential expansion of ethanol production and associated increase in the use of lignite in North Dakota.

Site Selection and Evaluation

Corn and barley production data from 1998 - 2002 in North Dakota and the adjacent counties in Minnesota and South Dakota were analyzed to determine the areas in North Dakota with the highest concentrations of feedstock for ethanol production. This data was used to select three sites for the study (#1-Hankinson, #2-Valley City, #3-Minot). Two sites in western North Dakota were added: #4 is at the Freedom Mine near Beulah and the other in an area where corn would be railed to the site (#5-Richardton).

The ethanol plant sizes that could be supported by the local corn and barley production are 40, 30 and 10 million gallons per year (MMGPY) at sites in Hankinson, Valley City and Minot, respectively. The ethanol plants in Beulah and Richardton are assumed to be 40 MMGPY plants because the size of the plants would not be restricted by local grain production. The Hankinson and Valley City sites have a slight edge over the other sites.

Financial Forecast

Lignite-fired ethanol plants were modeled using BBI's proprietary financial model. Internal Rate of Return (IRR) and Net Present Value (NPV) were used to measure the profitability of the proposed projects. NPV was calculated with 8% and 15% discount rates. The results are summarized in Table 1. The complete 10-year economic forecasts for each of the five sites are included in the appendix. The results indicate that lignite-fired ethanol production is feasible at plant scales of 30 MMGPY or greater. A comparison of the forecasted financial results indicates that the natural gas production scenario is more attractive than the comparable lignite-fired option. A +/- 50% sensitivity analyses of the average Energy Information Administration (EIA) forecast price of natural gas show that the projects will continue to cash flow with prices well above $6.00 per MCF.

The proposed lignite-fired ethanol projects have a range of projected NPVs (with an 8% discount rate) from a low of $(8,902,000) for the 10 MMGPY plant at site #3 to a high of $18,663,000 for the 40 MMGPY plant at site #1. The estimated total project investment is $33.1 million for the 10 MMGPY plant, $66.0 million for the 30 MMGPY plant and $83.1 million for the 40 MMGPY plant.

These results were compared against the financial forecast results for the same five sites using natural gas and purchased electricity (Table 2). The capital cost used in the lignite fired cogeneration scenarios was replaced with the cost for a thermal oxidizer-waste heat boiler, the standard design for natural gas-fired ethanol plants. The number of employees, electricity costs and other minor items were adjusted for a typical ethanol plant scenario.

Table 1 – Modeling Results for Lignite-Fired Ethanol Plants

	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
Internal Rate of Return	12.7%	11.0%	1.3%	11.4%	10.8%
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Cogen Plant Capital Cost	$26,300,000	$21,400,000	$12,200,000	$26,300,000	$26,300,000
Owner's Costs	$11,769,000	$10,080,000	$5,876,000	$11,788,000	$11,816,000
Total Project Investment	$83,069,000	$65,980,000	$33,076,000	$85,388,000	$85,416,000
Equity (100%)	$83,069,000	$65,980,000	$33,076,000	$85,388,000	$85,416,000
Net Present Value, 8% Discount Rate	$18,663,000	$9,217,000	($8,962,000)	$13,818,000	$11,305,000
Net Present Value, 15% Discount Rate	(6,768,000)	(9,170,000)	(13,824,000)	(10,671,000)	(12,420,000)

Table 2 – Modeling Results for Natural Gas-Fired Ethanol Plants

	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
Internal Rate of Return	17.7%	15.8%	12.9%	13.6%	13.6%
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Thermal Oxidizer/Waste Heat Boiler Capital Cost	$3,000,000	$2,500,000	$1,100,000	$3,000,000	$3,000,000
Owner's Costs	$11,086,000	$9,450,000	$5,437,000	$11,188,000	$11,188,000
Total Project Investment	$59,086,000	$46,450,000	$21,537,000	$61,488,000	$61,488,000
Equity (100%)	$59,086,000	$46,450,000	$21,537,000	$61,488,000	$61,488,000
Net Present Value, 8% Discount Rate	$29,150,000	$18,100,000	$4,964,000	$16,765,000	$16,765,000
Net Present Value, 15% Discount Rate	5,943,000	1,411,000	(1,583,000)	(3,206,000)	(3,206,000)

A comparison of the forecasted financial results indicates that the natural gas production scenario is more attractive than the comparable lignite-fired option.

Table 3 – Comparative Analysis for Natural Gas vs. Lignite-Fired Ethanol Plants

	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
NPV **8% discount rate** – Natural Gas Fired Plant	$29,150,000	$18,100,000	$4,964,000	$16,765,000	$16,765,000
NPV **8% discount rate** – Lignite Fired Plant	$18,663,000	$9,217,000	($8,962,000)	$13,818,000	$11,305,000
NPV **15% discount rate** – Natural Gas Fired Plant	5,943,000	1,411,000	(1,583,000)	(3,206,000)	(3,206,000)
NPV **15% discount rate** – Lignite Fired Plant	(6,768,000)	(9,170,000)	(13,824,000)	(10,671,000)	(12,420,000)

The NPV of the natural gas-fired plants is much higher than the NPV for the lignite-fired plants because the pre-tax income for both scenarios is comparable, but the capital investment for the natural gas option is significantly less than the lignite option.

Economic and Tax Impacts to the State of North Dakota

The cumulative economic and tax impacts of the two respective production scenarios for North Dakota are summarized in the table below.

Table 4 – Lignite Power vs. Natural Gas Power for ND Ethanol Plants

Construction Phase Impacts	**Lignite Power**	**Natural Gas Power**
Total Ethanol Plant Capital Costs (millions)	$352.9	$250.0
Final Demand Impact (millions)	$856.4	$606.8
Earnings Impact (millions)	$278.0	$197.0
Employment Impacts (indirect jobs)	8,685	6,153
Operations Phase Impacts	**Lignite Power**	**Natural Gas Power**
Total Operating Expenditures (millions)	$201.6	$209.7
Final Demand Impact (millions)	$395.6	$411.5
Earnings Impact (millions)	$70.4	$73.2
Employment Impacts (direct jobs)	237	162
Employment Impacts (indirect jobs)	2,129	2,215
Total Jobs	2,366	2,377
State Income Tax on Earnings (millions)	$4.2	$4.3
Tax Impacts and State Producer Payments	**Lignite Power**	**Natural Gas Power**
Personal Earnings Impact (millions)	$70.4	$73.2
North Dakota Personal Income Tax on Earnings	$4.2	$4.3
Average Pre-Tax Income (millions)	$39.4	$35.9
North Dakota Corporate Income Tax Revenue	$4.1	$3.8

Total Tax Revenue (millions)	$8.3	$8.1
State Producer Payment (millions)	$2.0	$2.0
Annual Return to State (millions)	$6.3	$6.1
Net Present Value (millions), 8% discount rate	$44.0	$85.7
Net Present Value (millions), 15% discount rate	($52.9)	($0.6)

North Dakota Ethanol Incentive

North Dakota has an ethanol production incentive program administered by the Agricultural Product Utilization Division of the Department of Commerce. The program is funded on a biennial cycle and funding for the period July 1, 2003, to June 30, 2005, is $0.40 per gallon. After June 31, 2005, the incentive amount will be calculated based on the price per bushel of corn and the price per gallon of ethanol, limited to $1,600,000 annually per eligible facility. Eligible facilities are defined as ethanol production plants constructed in North Dakota after July 31, 2003.

Ethanol Marketing Plan

The fact that existing ethanol production capacity exceeds the local market potential means that a new facility in North Dakota would need to market virtually all their production to regional or national outlets. The best scenario for an ethanol plant in North Dakota would be to focus marketing its ethanol production to regional outlets to the west and north, and national outlets on the West Coast.

Conclusions

- The use of natural gas to power an ethanol plant is more favorable than lignite. The natural gas-fired production scenario is the more attractive opportunity in terms of the agricultural community and value-added processing.

- The projected profitability of the 40 MMGPY lignite-fired ethanol plant at site #1 (Hankinson) is acceptable and is competitive with other projects BBI has evaluated throughout the Midwest.

- Sites #2, #4 and #5 have lower projected returns and are at the lower end of competitive ethanol projects based on the projected IRR's for the lignite-fired cogeneration option. With the natural gas-fired option the projected returns for these sites fall within the acceptable range. Site #3 is not feasible with the lignite-fired cogeneration production scenario, but is acceptable with a 12.9% IRR for the natural gas fired option.

- Additional work to refine the capital cost of the most promising technologies is recommended. The lignite-fired cogeneration plant is an issue and increase the required capital cost of an ethanol project a significant amount.

II. PROJECT OVERVIEW

The Industrial Commission of North Dakota (NDIC) is interested in determining the potential of using lignite as the primary fuel source for one or more ethanol plants to be built in North Dakota. BBI International has been retained to contribute to that effort as outlined below.

As outlined in North Dakota Century Code Chapter 54-17.5-0.1, the program is intended to maintain and enhance development of North Dakota lignite and its products; preserve and create jobs involved in the production and utilization of North Dakota lignite; ensure economic stability, growth, and opportunity in the lignite industry; and maintain a stable and competitive tax base for our state's lignite industry for the general welfare of North Dakota.

The traditional fuel for ethanol plants is natural gas with electricity typically purchased from a local utility company. The Energy Information Agency of the US Department of Energy provides natural gas forecast prices for the industrial sector by year. The EIA DOE forecast will be used as the basis for natural gas prices for this study. Recent increases in natural gas prices have impacted ethanol industry profits and fluctuations in gas prices continue to threaten the viability the ethanol product. In North Dakota, the use of low-cost lignite in an ethanol plant, in lieu of natural gas, may have the potential to provide a stable low-cost source of energy for ethanol plant operations.

The purpose of this feasibility study is to characterize the potential expansion of ethanol production and associated increase in the use of lignite (in lieu of natural gas) to produce energy for operation of new ethanol plants in North Dakota.

This study will identify on a cost-effective, economical basis, the number of lignite-powered ethanol plants that North Dakota agricultural production could support. The study will compare lignite powered ethanol plants to more traditional natural gas fired ethanol plants. The study will examine potential steam and electricity production technologies with minimal emissions that could be applied to ethanol production facilities, costs associated with using lignite, including transportation, and the most cost effective location for ethanol facilities that utilize lignite in North Dakota.

In the study BBI will address the following in order to meet all of the objectives of the project:

BBI will estimate the number, production capacity and location of new green-field lignite-based ethanol plants which could be built in North Dakota on a cost-effective, economical basis. To establish these findings infrastructure information will include the following:

- Historical production and pricing for local corn and barley
- Availability of operational needs such as rail, roads, water and water discharge

- Availability of markets for distillers grain and CO2 by-products
- Availability and delivered cost of lignite
- Infrastructure needs will address, at a minimum, the following:
    - Lignite transport (rail, truck) to point of use and associated public safety issues
    - Impacts of water usage on existing rural consumers
    - Minimum environmental gaseous emission and byproduct control requirements
    - Proximity of potential sites to communities

Using the above information, BBI will select specific areas where ethanol plants could be built in North Dakota. BBI will determine the optimal size of each plant based on the availability of feedstock, energy, ethanol and co-product market considerations.

BBI will provide an economic analysis of lignite utilization and compare that to the use of natural gas in the production cost of ethanol. The analysis will address the following:

- Assuming an integrated lignite-based fluidized bed combustor (FBC) or gasification co-generation process, compare the cost of ethanol production to the use of natural gas (variations of natural gas prices will be considered).
- Determine ethanol and co-product markets that could be competitively served by North Dakota ethanol plants and the historical ethanol and co-product pricing in those markets
- The estimated increase of lignite usage.
- The cost and mode of lignite transport (rail or truck) to the ethanol production facility.

BBI will incorporate this information into its proprietary financial model to evaluate the economic performance of the proposed ethanol plants. The production costs for ethanol produced with lignite-derived energy will be compared to the production costs with natural gas. A series of sensitivity analyses will be performed for critical project parameters including the cost of corn and barley, the selling price of ethanol, the cost of lignite, and the cost of natural gas.

III. SITE SELECTION AND EVALUATION

The criteria for a good ethanol plant site encompass many factors. Proximity of feedstocks, good road and rail access, utility availability and space for equipment and truck movement are necessary. Other considerations include a qualified and/or trainable labor force, as well as community facilities that are capable of attracting and retaining top management personnel who may come from outside the area. Access to an airport is important as well as good medical facilities. A large cattle feedlot near a site would allow for feeding of wet distillers grains to cattle, resulting in significant energy savings.

Study Area and Identification of Potential Facility Sites

The study area for the present analysis encompasses the entire state of North Dakota. BBI collected and analyzed data required to select ethanol plant sites and to determine the size of those ethanol plants. Corn and barley production data from 1998 through 2002 in North Dakota and the immediately adjacent counties in Minnesota and South Dakota were analyzed to determine the areas in North Dakota with the highest concentrations of feedstock for ethanol production. This data was used to select three sites for the study (sites #1 – #3 in Figure 1). Historical grain production within a 40- or 50-mile radius of the sites was then used to estimate the size of an ethanol plant at each site.

Two additional sites in western North Dakota were added – one at a lignite mine (the Freedom Mine near Beulah, site #4 in Figure 1) and the other in an area where corn would be railed to the site (Richardton, site #5). The five sites are shown in the map below. The green shading in the map shows the relative density of corn and barley production by county. The red pushpins indicate existing ethanol plants and the blue pushpins indicate other proposed ethanol projects in North Dakota.

Corn production is highest in the southeast part of the state and this area was selected as one of the potential plant locations. The corn and barley production data for a plant in Richland County (site #1) is summarized in Table 5 below. An ethanol plant located in this area is assumed to draw corn from all or part of the 11 counties within 40-miles of a plant site near Hankinson in the southeast corner of Richland County. Corn production in the 40-mile radius feedstock area for site #1 has averaged nearly 65 million bushels per year for the five years (from 1998 through 2002). Barley production has averaged over 1.5 million bushels annually during this period.

The resulting ethanol production potential is based on using 25% of the average corn and barley production in the 40-mile radius feedstock area and yields of 2.8 gallons of denatured ethanol from each bushel of corn and 2.2 gallons from each bushel of barley. Based on these assumptions, the ethanol production potential is about 45 million gallons from corn and less than one million gallons from barley. This area could support a 40 million gallon per year (MMGPY) dry mill ethanol plant. BBI proposes that the study include a 40 MMGPY ethanol plant in Richland County near Hankinson, ND.

Figure 1 – Proposed Ethanol Plant Sites with 40- and 50-mile Radius Feedstock Collection Areas and Bushels of Combined Corn and Barley Production

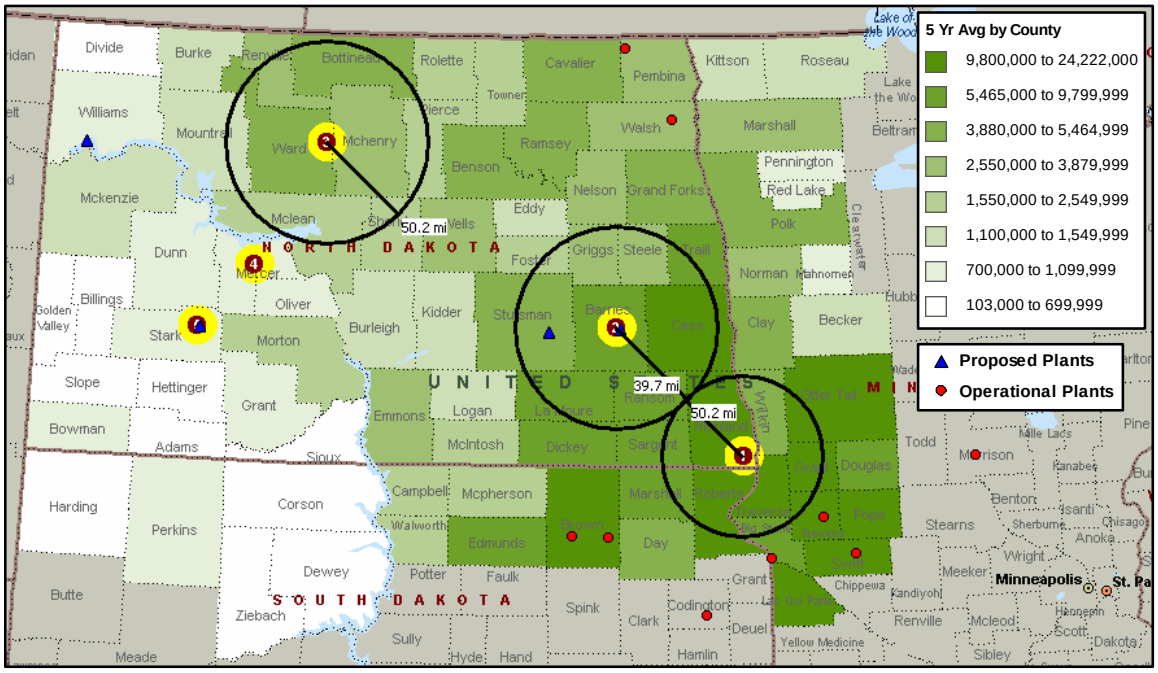


Table 5 – Annual Corn and Barley Production for Site #1 and Resulting Ethanol Production Potential (gallons) by County

County	State	% in 50-mile Radius	Available Corn (bushels)	Corn Ethanol Potential	Available Barley (bushels)	Barley Ethanol Potential
Ransom	ND	10%	616,446	431,512	34,520	18,986
Richland	ND	90%	21,468,726	15,028,108	330,840	181,962
Sargent	ND	30%	2,338,140	1,636,698	49,380	27,159
Marshall	SD	25%	1,946,550	1,362,585	20,250	11,138
Roberts	SD	80%	7,736,480	5,415,536	309,120	170,016
Big Stone	MN	20%	1,935,596	1,354,917	0	0
Grant	MN	66%	6,445,837	4,512,086	111,685	61,427
Otter Tail	MN	15%	2,271,966	1,590,376	46,026	25,314
Stevens	MN	15%	2,974,608	2,082,226	0	0
Traverse	MN	100%	13,307,180	9,315,026	187,080	102,894
Wilkin	MN	90%	4,418,154	3,092,708	496,296	272,963
TOTAL			**64,843,237**	**45,390,266**	**1,550,677**	**852,872**

A similar analysis was conducted for sites #2 and #3 and the results are summarized for sites #1, #2 and #3 in Table 6. The corn and barley and ethanol production potential data for each 50-mile radius feedstock area for plants #2 and #3 are presented in Table 7 and Table 8.

Table 6 – Annual Corn and Barley Production & Ethanol Production Potential and Resulting Ethanol Plant size

Plant #	Corn Production 5 Yr Avg (bu)	Corn Ethanol Potential (gal)	Barley Production 5 Yr Avg (bu)	Barley Ethanol Potential (gal)	Combined Ethanol Potential (gal)	Ethanol Plant Size (MMGPY)
Plant #1	64,843,237	45,390,266	1,550,677	852,872	46,243,139	40
Plant #2	25,546,881	17,882,817	11,464,010	6,305,206	24,188,022	30
Plant #3	1,296,879	907,815	15,874,658	8,731,062	9,638,877	10

Table 7 – Annual Corn and Barley Production for Site #2 and Resulting Ethanol Production Potential (gallons) by County

County	State	% in 50-mile Radius	Available Corn (bushels)	Corn Ethanol Potential	Available Barley (bushels)	Barley Ethanol Potential
Barnes	ND	100%	3,025,680	2,117,976	3,229,200	1,776,060
Cass	ND	80%	7,434,000	5,203,800	1,125,600	619,080
Foster	ND	25%	161,270	112,889	411,450	226,298
Griggs	ND	75%	435,570	304,899	1,481,100	814,605
La Moure	ND	80%	4,025,104	2,817,573	1,396,800	768,240
Ransom	ND	100%	6,164,460	4,315,122	345,200	189,860
Steele	ND	75%	1,733,175	1,213,223	1,162,350	639,293
Stutsman	ND	60%	1,064,472	745,130	2,067,360	1,137,048
Trail	ND	25%	1,503,150	1,052,205	244,950	134,723
TOTAL			**25,546,881**	**17,882,817**	**11,464,010**	**6,305,206**

Table 8 – Annual Corn and Barley Production for Site #3 and Resulting Ethanol Production Potential (gallons) by County

County	State	% in 50-mile Radius	Available Corn (bushels)	Corn Ethanol Potential	Available Barley (bushels)	Barley Ethanol Potential
Bottineau	ND	100%	194,300	136,010	4,535,000	2,494,250
McHenry	ND	100%	599,660	419,762	2,214,000	1,217,700
McLean	ND	50%	143,520	100,464	1,061,400	583,770
Mountrail	ND	20%	6,492	4,544	254,800	140,140
Pierce	ND	50%	141,590	99,113	1,124,100	618,255
Renville	ND	70%	60,256	42,179	2,383,220	1,310,771
Sheridan	ND	33%	21,533	15,073	543,378	298,858
Ward	ND	90%	129,528	90,670	3,758,760	2,067,318
TOTAL			**1,296,879**	**907,815**	**15,874,658**	**8,731,062**

Site #1 is assumed to be located in or near Hankinson which has excellent rail connections, with both BNSF and Canadian Pacific (CP) running through town, and the town is also the site of a large propane plant. Hankinson is just three miles west of Interstate 29 in Richland County. There are no known ethanol projects planned for the area, but there are several ethanol plants to the east and south in Minnesota and South

Dakota and the ProGold corn wet mill is located about 20 miles to the northeast in Wahpeton, ND. There is relatively little barley grown in the area and the plant at site #1 is assumed to use all corn for it's feedstock for ethanol production.

Site #2 is assumed to be near Valley City, which has access to two railroads. Valley City is about 60 miles west of Fargo on Interstate 94. Corn is the predominate local crop with a significant amount of barley also grown in the area. Dakota Renewable Fuels LLC has announced that it plans to build a 40 MMGPY corn dry mill near Valley City and another group is considering a plant in Jamestown, about 30 miles to the west of Valley City. BBI is not proposing that a second (or third) ethanol plant be built in the Valley City area; rather we agree that this is a good area for a plant due to the local corn production and the transportation infrastructure. There is more barley in this area compared to site #1, but again the plant at site #2 is assumed to use corn for ethanol production.

Site #3 is assumed to be located near Minot in north central North Dakota. The actual site could be anywhere along the BNSF rail line in the area and BBI recommends that the site be at least one-half mile away from residential areas. The Minot area grows mostly barley with some corn grown in a 50 mile radius. The ethanol plant at site #3 is assumed to use all barley for ethanol production.

Site #4 is at the Freedom Mine near the Antelope Valley Station north of Beulah. The site is served by the BNSF (via Zap, ND). There is very little corn or barley production in the area, so this site is assumed to rail in corn for ethanol production. The Freedom Mine site was added as a site that would be representative of an ethanol plant located at a lignite mine rather than at the source of the feedstock for ethanol production (corn and barley). Other lignite mine locations could be substituted for this location.

Site #5 is assumed to be located in or near Richardton. The Richardton site was added to represent a site that is not located at the source of the lignite or the corn or barley feedstock supply. A Richardton group has announced plans to build a 50 MMGPY corn dry mill near Richardton. BBI is not proposing that a second ethanol plant be built in the area; rather we have chosen the Richardton site to evaluate transporting both corn and lignite. Other areas in western North Dakota could be substituted for Richardton.

The ethanol plants that BBI proposes to include in the feasibility study are located in Richland, Barnes, Ward, Mercer and Stark Counties. The ethanol plant sizes that can be reasonably expected to be supported by the local corn and barley production are 40, 30 and 10 MMGPY at sites #1, #2 and #3 in Richland, Barnes and Ward Counties, respectively. The ethanol plants at sites #4 and #5 (Mercer and Stark Counties) are assumed to be 40 MMGPY plants because they will not use much, if any local feedstock and the size of the plants are not restricted by local grain production. These plants are assumed to rail corn to the site from eastern North Dakota and western Minnesota.

It should be noted that local wheat production was not included in the analysis because several studies conducted by BBI have shown that wheat in the U.S. is too expensive to be competitive with corn for fuel ethanol production. Barley is typically not used for

ethanol production, but several projects are considering its use due to low prices (for feed barley) compared to corn.

A site in northeast North Dakota was originally considered, but it was rejected because it would be too close to the existing Walhalla and Grafton ethanol plants. These plants have a combined nameplate ethanol production capacity of 41 MMGPY. Another plant in this area would create too much demand for local corn and could threaten the viability of all of the plants in the region. It is important to avoid creating too much upward pressure on local grain prices when siting ethanol plants.

The BBI Site Evaluation Matrix

The BBI Site Evaluation Matrix was used to evaluate the five project sites. The Site Evaluation Matrix assigns weighted scores for desirable site attributes including:

- Feedstock availability
- Road and rail transportation
- Energy supply (normally natural gas and electricity – lignite in this case)
- Utilities including water and wastewater
- Ethanol and co-product market proximity
- Labor availability
- Community services such as welding, electrical shop, plumbing, schools, fire protection, hospital and airport
- Proximity to local communities

BBI's Site Evaluation Matrix was modified to account for the use of lignite to produce steam and electricity onsite rather than purchase these utilities from local suppliers.

Each of the key items that determine the suitability of an ethanol plant site is discussed below. The feedstock supply and ethanol and DDGS markets are reviewed in more detail in following sections of this report. Scores have been assigned to each of the key site attributes and the scores are presented below in Table 15. A discussion of the scores assigned to each component of the site evaluation for each site follows.

<u>Feedstock Proximity</u>

The availability of feedstock is an important component of the site evaluation as well the overall feasibility of an ethanol plant. The feedstock proximity is reviewed briefly here and is discussed in more detail in the feedstock section of this report.

A score of up to 10 points is awarded to a site that has adequate feedstock (corn and barley for this study) for the ethanol plant size established earlier within 50 miles of the site. Fifty miles is a typical truck haul for delivering grain to an ethanol facility. Longer hauls are possible and may occur in certain markets.

Site #1 is near Hankinson in Richland County in the southeast corner of the state where corn production is the highest. The site has more than adequate corn available in just a 40 mile radius for a 40 MMGPY plant and was awarded 10 points for an adequate corn supply.

Site #2 near Valley City has inadequate corn and barley supply within a 50 mile radius for a 30 MMGPY plant and corn will likely be sourced from a greater distance. Site #2 was, therefore given a score of 6 out of 10 for feedstock proximity.

Site #3 near Minot has slightly less than adequate production of corn and barley within 50 miles of the site and may have to source some barley or corn from greater than 50 miles. Site #3 was, therefore given a score of 8 for slightly less than adequate feedstock supply within 50 miles.

Sites #4 and #5 are in western North Dakota where corn and barley production are very low. Local corn production in these areas is inadequate to supply the proposed 40 MMGPY facilities. The feedstock for these sites is assumed to be railed in from southeastern North Dakota with additional supplies being shipped in from the adjacent corn-producing states of Minnesota and South Dakota. Corn may also be imported from the nearby corn-producing states of Iowa and Nebraska, as dictated by price. Because sites #4 and #5 will be drawing feedstock from areas beyond 100 miles of the sites, the sites were awarded a score of 2 out of 10 for feedstock proximity. If ethanol plants were to be built at these sites they may stimulate a significant increase in the amount of local acreage planted in corn or barley, once the plant is up and running.

Additional details regarding feedstock availability and pricing are provided in the Feedstock section of this report.

Proximity to Communities

Ethanol plants bring numerous benefits to communities and the surrounding region in the form of high paying jobs, value added to local crops and significant general economic development. There are however, potential negative impacts such as increased traffic and visual impacts. Odors from modern dry mill ethanol plants are no longer a significant issue with the introduction of thermal oxidizers, which remove odors from the distillers grain dryer exhaust stream.

It is assumed that all of the sites will be located a minimum of one-half mile from residential areas to avoid sound, odor and visual impacts on communities. In addition, the sites are in areas predominantly used for agricultural purposes and are surrounded by farmland or ranchland. Due to the recommended distance from residential areas for siting the plants, all of the sites were awarded the maximum score of 6 points for proximity to communities and rural locations.

Transportation

Access to rail for shipping ethanol and distillers grains to more distant markets can provide a distinct advantage over ethanol plants without rail access. A site on a mainline rail line is better than a location on a short line rail line. Access to two rail lines is also a positive site attribute.

All of the sites are located on the Burlington Northern and Santa Fe Railway (BNSF), the second largest railroad company in the U.S. All of the sites received 10 points for mainline rail.

The Hankinson (site #1) and Valley City sites (site #2) have access to two railroads which can result in lower shipping costs due to competition for rail traffic. These sites received an additional 8 points for the second rail line. The five sites were awarded the scores shown in Table 15 for rail access.

Access to good roads is also important to an ethanol plant because the feedstock is typically delivered by truck and ethanol and distillers grain are shipped to local markets by truck. Access to an interstate is an advantage over a site on a state or county highway. Sites #1, #2 and #5 are located near Interstate 29 or 94 and received a score of 8 points for interstate road access. Sites #3 and #4 are located on state or county highways and received a score of 4 points for road access.

Electrical Service

Electrical power will be provided by the onsite lignite fired power plant. A score for local electrical service is therefore not required. Standby and backup power would be required at each site and is assumed to be available. An alternative to grid backup power would be diesel generators. The analysis and selection of the best backup power supply is beyond the scope of the feasibility study and should be addressed in any subsequent follow up project development work.

Each ethanol plant will use approximately 0.8 kWh per gallon of ethanol produced, not including the parasitic power for the power plant. The power required by the ethanol plant can vary slightly depending upon the process design company employed. A 40 million gallon per year ethanol plant will use approximately 3.6 MW of power, or about 30,500,000 kWh of electrical energy per year. Annual use is based on a 24/7 operation and 350 days of operation per year. The power demand and annual electricity use of the other ethanol plant sizes are shown in the table below.

Table 9 – Ethanol Plant Electricity Use

Plant Size	Electricity Use	Demand	Annual Use
10 MMGPY	0.8 kWh/gallon	0.91 MW	7,636,000 kWh
30 MMGPY	0.8 kWh/gallon	2.73 MW	22,909,000 kWh
40 MMGPY	0.8 kWh/gallon	3.64 MW	30,546,000 kWh

It should be noted when considering electrical service, the benefit to the state for coal conversion applied to electrical generation is lost if the corn to ethanol plant generates its own electrical service via on-site cogeneration. Electrical generation plants pay a tax of 0.65 mills/kW of installed capacity times 60% of the number of hours in a taxable period, plus 0.25 mills per kWh of electricity produced for sale. Since the required power for the combined feasibility plants is 13.74 MW, the generation tax would be $45,000, which the state would receive only if generated in a large-scale ND power plant. No tax would be collected by the on-site lignite-fired cogeneration system since the electricity produced (per plant site) is less than 10 MWe and not produced for sale.

Natural Gas

Natural gas is not required at the proposed ethanol plant sites due to the use of lignite for steam and electricity production. A score for local natural gas supply is therefore not required. Natural gas or propane may be needed to heat the lignite fired boiler prior to startup, however.

For the comparative analysis against the conventional natural gas-fired ethanol plant design, the price of natural gas will be those forecast by the DOE Energy Information Agency for the industrial sector by year through 2014 as shown in the following table.

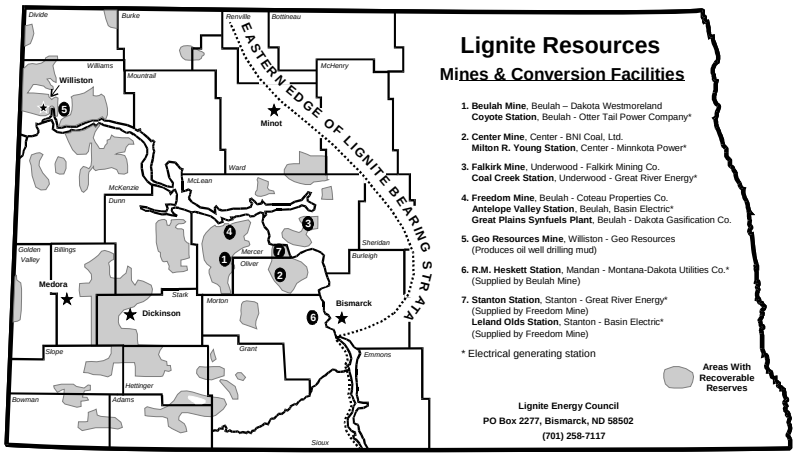
Table 10 – Natural Gas Prices Forecast through 2014
(Source: US DOE EIA)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
$/mcf	4.28	4.21	4.25	4.35	4.22	4.16	4.31	4.49	4.67	4.78

Lignite Supply

Lignite to power the ethanol plants will be supplied by North Dakota lignite mines located in the western region of the state. The locations of the primary mines in the state are shown on the map below.

Figure 2 – North Dakota Lignite Mines



The approximate amount of lignite required for each ethanol plant is shown in the table below.

Table 11 – Estimated Steam and Lignite Demand for North Dakota Ethanol Plants

Plant #	Ethanol Plant Size (MMGPY)	Combined Co-gen Demand (MWeq)	Combined Energy Demand (MMBTU/Hr)	Lignite Heating Value (BTU/LB)	Lignite Use (TONS/HR)	Lignite Use (TONS/YR)
Plant #1	40	60.51	206	6,750	15.29	128,461
Plant #2	30	45.37	155	6,750	11.47	96,325
Plant #3	10	15.12	52	6,750	3.82	32,108
Plant #4	40	60.51	206	6,750	15.29	128,461
Plant #5	40	60.51	206	6,750	15.29	128,461
TOTAL	**160**	**242**	**825**	**6,750**	**61.2**	**513,816**

Each ethanol plant was awarded a score based on the distance from the lignite mines to the ethanol plant to reflect the higher transportation costs for the lignite for plants that are further away. Site #1 is about 300 miles from the lignite mines and received a score of 4 points out of 10. Site #2 is closer to the mines at about 200 miles and received a score of 5. Site #3 is near Minot and is less than 100 miles from the Falkirk mine and received a score of 6 out of 10.

Site #4 is located at the Beulah mine and received the maximum score of 10 points for being located at the mine. Site #5 is located at Richardton and is about 50 miles from the Beulah or Center mine and received a score of 7 points.

Lignite for the Hankinson and Valley City sites would be sourced based on price and delivered by rail. Lignite for the Minot site would be sourced from the Falkirk mine and trucked to the site. Lignite for the Richardton site would be sourced from the Center mine and trucked to the site.

Water

There are three basic sources of water used for ethanol plants: well water, municipal water and river water. Most plants use well water because of their rural location. Over the long term, well water is often less expensive. Cost of drilling, quality of well water and long-term supply are important considerations when considering a new well.

Water requirements for a 40 million gallon per year ethanol plant can vary from about 400,000 to 650,000 gallons per day (275-450 gpm) depending upon the design of the plant and the quality of the makeup water. For the present study, a 40 MMGY plant is estimated to require 485,000 gallons per day of makeup water and the 30 and 10 MMGPY plants proportionately less – 363,000 and 121,000 gallons per day, respectively.

Ample ground water is reported to be available in the general area of each site. Hardness of the water could be an issue and hardness testing of the water is recommended prior to

final site selection. The cost of a reverse osmosis system has been included in the capital cost estimates for the ethanol plant to reduce the water hardness.

Because the makeup water is treated with reverse osmosis (RO) prior to use, the salinity of the source water will have little or no effect on the quality of the distillers grain co-product. Rather, the salinity will have an effect on the size and operating costs of the RO system. The effect of water salinity and hardness on plant operations and the distillers grain co-product should be reviewed and confirmed once a design firm is selected, as there are minor differences between the various ethanol process designs in use today.

Due to availability of adequate well water in close proximity to the proposed sites, a score of 7 out of a possible 7 points was applied.

Wastewater

Modern ethanol plants are typically designed to be zero process wastewater effluent facilities. Process water is normally not discharged from the plant; it is recovered and recycled in the dry mill process. Most plants do have a water discharge from the reverse osmosis system and from the cooling tower. The cooling tower must be "blown-down" to prevent scale buildup in the equipment. The RO and blowdown water is typically very similar to the makeup water, but with an increase in the hardness. RO and cooling tower blowdown is typically discharged to a local sewer, to surface water with appropriate permits, to an evaporation pond or to a holding pond for irrigation.

A 40 million gallon per year ethanol plant would produce about 100,000 gallons of wastewater per day (67 gpm), although this number can vary considerably with plant design and makeup water quality. Similarly, a 30 MMGPY plant will generate approximately 73,000 gallons of wastewater per day (50 gpm) and a 10 MMGPY plant will produce about 24,000 gallons per day (17 gpm). Again, these amounts can vary depending upon the quality of the makeup water and the ethanol plant design.

All of the sites should have the ability to use an evaporation pond, irrigate cropland, or access to a creek or river for plant discharges. An evaporation pond combined with land application is the most likely alternative for the limited discharges produced by the proposed plant. The proposed sites would not likely have access to a city sewer due to the rural locations. A city sewer, if available, would likely be the preferred discharge option.

Based on these considerations, 5 points were awarded each site for possible application of wastewater to crops or discharge to "surface" waters with appropriate permits.

Co-product Market Proximity

The co-product market for the project is discussed in detail later in this report. For purposes of the site evaluation, the distillers grains co-product market proximity is reviewed briefly here.

Approximately 18 pounds of distillers dried grains and solubles (DDGS) are produced from each bushel of corn or barley processed. A 40 million gallon per year ethanol plant will therefore produce about 129,000 tons of DDGS annually; a 30 MMGPY plant will generate about 96,000 tons and a 10 MMGPY plant will generate about 32,000 tons of DDGS annually. Feeder cattle will typically consume between 4 and 8 pounds of DDGS per day depending upon the ration prescribed by the owner or the owner's nutritionist.

Four pounds of DDGS per day is equivalent to ¾ tons per year and eight pounds per day is equivalent to 1.5 tons per year. We will assume one ton per year per cow for estimating the DDGS market size required for each ethanol plant.

At a rate of one ton of DDGS per cow per year (6 pounds per day), approximately 129,000 head of cattle are required for the DDGS output of a 40 million gallon per year dry mill ethanol facility, 96,000 head for a 30 MMGPY plant, and 32,000 head are required to utilize the DDGS generated from a 10 MMGY plant.

The DDGS production for each ethanol plant and the number of cattle within a local market radius for each site is shown in the table below. We have defined the "local DDGS market" to be the area within 100 miles of the 40 MMGPY plants, 75 miles for the 30 MMGPY plant, and 30 miles for the 10 MMGPY plant.

As can be seen from Table 12, the number of cattle near each plant is very significant and the percentage of the cattle that would be required to use the DDGS produced is a small fraction of the total cattle in each local DDGS market.

The local co-product markets for DDGS are judged to be very good for all of the sites and each site received a score of 8 points out of 10 for co-product market proximity. However, local markets will require time and effort to develop.

Table 12 – Local DDGS Markets and Cattle Data

Site	Ethanol Plant Size (MMGPY)	DDGS Produced (tons/year)	Local DDGS Market Radius (miles)	All Cattle within Local DDGS Market	% of Cattle Needed for DDGS Output
Site #1	40	129,000	100	1,677,607	8%
Site #2	30	96,000	75	855,480	11%
Site #3	10	32,000	30	204,200	16%
Site #4	40	129,000	100	1,615,247	8%
Site #5	40	129,000	100	1,615,247	8%

Source for cattle data: http://www.usda.gov/nass; 1998 - 2002, all cattle inventory

Ethanol Market Proximity

A large local ethanol market can provide a distinct advantage for an ethanol plant through lower shipping costs. The ethanol market for the project is discussed in detail later in this report. For purposes of the site evaluation, the ethanol market proximity is reviewed briefly here.

Fuel ethanol use in North Dakota over the past five years has been low, with annual usage in the state in the range of four to six million gallons per year. Annual consumption reached a high of 6.7 million gallons per year in 2001 (source US Department of Transportation; data not yet available for 2002).

There are two ethanol plants currently in operation in North Dakota with a combined total production capacity of 41 MMGPY. Based on ethanol usage in the state, existing ethanol production facilities within the region, and the current excess in capacity for markets within the state, the bulk of any ethanol produced by new plants would most likely be exported to out of state markets, both regional and national. Each site was therefore given a score of 2 out of 10 points for ethanol market proximity.

Labor Availability

A 40 million gallon per year ethanol plant will require approximately 36 employees with about 34 required for a 30 MMGPY plant and about 20 required for a 10 MMGPY plant. The exact number of employees can vary depending upon the plant design and operating plan (see Table 13 below). The area within 25 miles of each site should be able to supply the majority of the labor for the ethanol plant operations. Specialty positions such as the plant manager and microbiologist may have to be recruited from greater distances. The maximum available score of 7 was applied for the labor availability component of the site evaluation matrix.

Table 13 – Comparison of Employment Requirements

Summary of Labor Requirements	Site #1	Site #2	Site #3	Site #4	Site #5	TOTAL
Lignite-Fired Ethanol Plant						
Direct Jobs	51	49	35	51	51	237
Indirect Jobs	520	387	153	532	536	2,129
Total Jobs	571	436	188	583	587	2,366
Natural Gas-Fired Ethanol Plant						
Direct Jobs	36	34	20	36	36	162
Indirect Jobs	538	402	149	563	563	2,215
Total Jobs	574	436	169	599	599	2,377

Community Services

Community services within 20 miles of the ethanol plant site are important to provide quick response to the needs of the plant and to attract and retain top employees. Desirable community services include electrical maintenance, machine shop, welding, plumbing, hospital, airport, good schools and fire protection. The communities near each site are capable of supporting the ethanol plants and all of the sites were given a score of 7 out of 7 possible points.

Results of Site Scoring

The results of the site scoring are presented in Table 14 and Table 15. The sites are ranked as follows:

Table 14 – Summary of Site Evaluation Scores

Rank	Site	Location	Score
1	Site #1	Hankinson	82
2	Site #2	Valley City	79
3	Site #3	Minot	70
4	Site #5	Beulah	68
5	Site #4	Richardton	69

Based on the weighted scores developed using the BBI Site Evaluation Matrix, site #1 near Hankinson received the highest score with 82 points. The Valley City site is the second highest ranked site with 79 points. The remaining sites are closely ranked with scores of 70, 68 and 69 for the Minot, Beulah and Richardton sites, respectively.

Table 15 – Site Evaluation Scores

Plant Siting Criteria	Maximum Points	Site 1	Site 2	Site 3	Site 4	Site 5
Adequate Feedstock < 50 mi.	10	10	6	8	2	2
Proximity of Communities	6	6	6	6	6	6
Rail						
Mainline Rail	10	10	10	10	10	10
Short line Rail	6	-	-	-	-	-
Access to two Railroads	8	8	8	-	-	-
Roads/Highways						
Intestate Road Access	8	8	8	-	-	8
State Highway Road Access	4	-	-	4	4	-
Distance to Lignite Source						
On site	10	-	-	-	10	-
Within 50 mile of site	7	-	-	-	-	7
Within 100 mile of site	6	-	-	6	-	-
Within 200 mile of site	5	-	5	-	-	-
Within 300 mile of site	4	4	-	-	-	-
Over 300 mile from site	3	-	-	-	-	-
Water						
Adequate Water Available	7	7	7	7	7	7
Wastewater Discharge						
To city treatment system	7	-	-	-	-	-
To Surface Waters or Land	5	5	5	5	5	5
Co-product Market Proximity	10	8	8	8	8	8
Ethanol Market Proximity	10	2	2	2	2	2
Labor Availability	7	7	7	7	7	7
Community Services	7	7	7	7	7	7
Total Points	**100**	**82**	**79**	**70**	**68**	**69**

All of the sites are judged to be good sites with the primary difference being the availability of a second rail line for the Hankinson and Valley city sites. Using lignite for on-site power production eliminates the need for natural gas. Without the need for natural gas, the primary consideration for siting the ethanol plants becomes the availability and cost of feedstock, availability of water and access to a mainline rail system.

Land requirements will be about 40 acres for the 40 MMGPY plants including the power plant and considerably less for the 10 MMGPY plant. Additional space will be required if a unit train grain receiving facility is to be included. In most cases the actual footprint of the plant is the least demanding in terms of space requirements. Other issues such as truck movement, future expansion, rail, and potential changes in products produced impact the size requirements to a far greater extent. It is important that the site size be visionary and that future expansion not be limited by the availability of land.

Required State and Federal Permits

BBI has compiled a list of local, state and federal permits typically required for the construction and operation of ethanol production plants. The following lists summarize the probable permit requirements as they pertain to the proposed projects in North Dakota. The general permit requirements are the same for lignite-fired or natural gas-fired plants, however the emissions control equipment required to meet those requirements would depend on the specific combustion technology incorporated into the plant design.

<u>Federal Permits</u>

Clean Air Act

- Prevention of Significant Deterioration (PSD) and Construction Permits
- Applicable Federal New Source Performance Standards (NSPS)
- Applicable National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Title V Operating Permit of the Clean Air Act Amendments of 1990
- Risk Management Plan

Clean Water Act

- National Pollutant Discharge Elimination System (NPDES)
- Oil Pollution Prevention and Spill Control Countermeasures

Comprehensive Environmental Response Compensation and Liability Act & Community Right to Know Act (CERCLA/EPCRA)

- Tier II Forms – listing of potentially hazardous chemicals stored on-site
- EPCRA Section 313 and 304 and CERCLA Section 103. These reports track use and release of regulated substances above threshold and/or designated quantities annually.

Bureau of Alcohol, Tobacco, and Firearms (BATF)

- Alcohol Fuel Permit (AFP)

State Permits

- Air Quality Permits
- Water Quality Permits
- State Liquor License
- State Department of Motor Fuels
- State Department of Transportation
  - Highway Access Permit
  - Rail Access Permit
  - Possible Easement Rights
- State Department of Health
  - Septic System
  - Private Drinking Water System
- State Fire Marshall
  - Boiler License
  - Above Ground Petroleum Storage Tanks
- State Department of Natural Resources
  - Water appropriation permits
  - Other water and wetland considerations

Local Permits

- Building Permits
- Zoning
- Electrical and other construction permits

Site Issues and Recommendations

Based on the results of the BBI Site Evaluation Matrix, all of the sites are judged to be adequate with the Hankinson and Valley City sites having a slight edge over the other sites. It is important to note that this evaluation of the sites does not necessarily mean that ethanol plants located at the sites will be profitable. That analysis will be performed in the Financial Analysis section later in the report.

If any of the sites are to be developed, the property selected for further development would optimally have the follow attributes:

- The ethanol plant site should be on the BNSP rail line
- A site with an existing rail siding would lower the capital costs for rail access
- The site should be at least ½ mile from residences, although it is not uncommon for ethanol plants to be closer
- A reliable water supply is a must

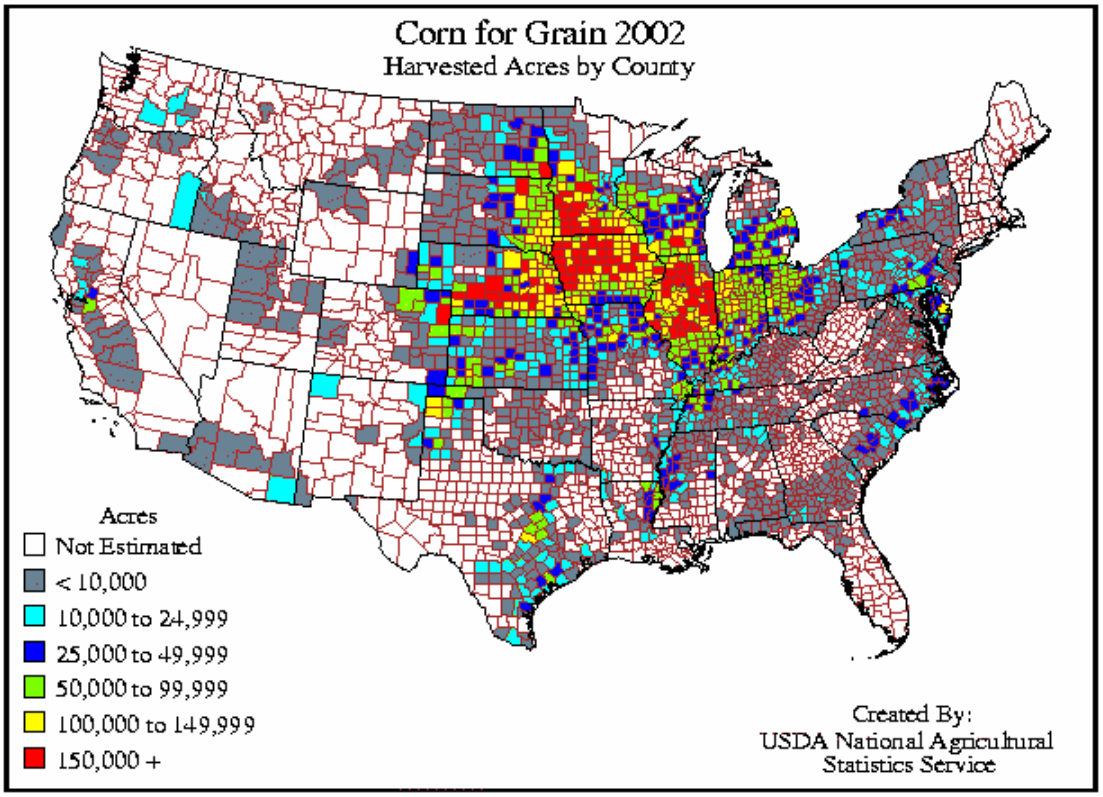
- There are several options for the plant's water discharge so this usually does not impact site selection to a great extent
- At least 40 acres is recommended for the 30 and 40 MMGPY plants and 10 to 15 acres for the 10 MMGPY plant
- the level of acceptance of the project by the local communities is important
- Sites should be evaluated by an ethanol process design company from an engineering and construction perspective

IV. FEEDSTOCK AVAILABILITY AND PRICE

The principal feedstock under consideration for the proposed ethanol plants is #2 yellow corn. This section of the report reviews the available supplies and historical pricing trends of the proposed feedstocks.

Corn is the largest agricultural crop grown in the United States and is the predominant feedstock for the U.S. ethanol industry. Approximately 80 million acres of corn are planted each year producing nine to ten billion bushels of corn. Figure 3 shows the density of corn production in the United States for 2002, based on the number of acres harvested per county.

Figure 3 – National Corn Production in the US



As can be seen in the figure, corn production in the US is concentrated in the northern Midwest, in the states of Minnesota, Iowa, Illinois, Nebraska, Indiana, Wisconsin and South Dakota. North Dakota was the thirteenth-ranked corn producing state in the country in 2002 (Table 16).

The data indicate that ethanol production in North Dakota consumes less than 10% of the state's annual corn crop, and that the impact of a 40 MMGPY ethanol plant on regional supplies would be minimal.

Table 16 – Top Corn Producing States in 2002
(Data from USAD NASS)

2002 Production Totals and Ranking					
Rank	State	bushels (000s)	EtOH Potential (gal)	# of Plants	Existing Capacity (gal)
1	Iowa	1,963,500	5,242,545,000	10	164,500,000 plus
2	Illinois	1,496,000	3,994,320,000	5	205,000,000 plus
3	Minnesota	1,051,900	2,808,573,000	14	370,500,000
4	Nebraska	940,800	2,511,936,000	7	389,000,000
5	Indiana	631,620	1,686,425,400	1	85,000,000
6	Wisconsin	391,500	1,045,305,000	3	58,000,000
7	South Dakota	304,000	811,680,000	8	210,000,000
8	Kansas	290,000	774,300,000	5	98,500,000
9	Missouri	283,500	756,945,000	2	41,000,000
10	Ohio	252,560	674,335,200	0	0
11	Michigan	232,300	620,241,000	1	40,000,000
12	Texas	205,660	549,112,200	0	0
13	North Dakota	114,425	305,514,750	2	38,500,000
	TOTAL	**8,157,765**	**21,781,232,550**	**58**	**1,700,000,000**

General Process Parameters

Starch and protein content for corn and the yields of ethanol, distillers grain (DDGS) and carbon dioxide (CO_2) used in this study are shown in Table 17. Ethanol, DDGS and CO_2 yields are based on typical process guarantees for new dry mill ethanol plants.

Table 17 – Composition and Yields for Corn

Starch (dry basis)	Protein (dry basis)	Ethanol Yield (gal/bushel)	DDGS Yield (lb/bushel)	CO2 Yield (lb/bushel)
71%	9%	2.8	18.0	16.0

Corn bushel = 56 lbs, 14% moisture. Ethanol and DDGS yields based on industry averages for new dry mill ethanol plants. Ethanol yield is denatured ethanol. DDGS yield includes 10% moisture.

The amount of feedstock required and co-product production for 10, 30 and 40 MMGY ethanol facilities are provided in Table 18. DWG is distillers wet grain with 65% moisture.

Table 18 – Grain Requirements and Co-Products for Ethanol Plants

Ethanol Capacity (gpy)	Corn Required (bu/yr)	DDGS (tons/yr)	CO_2 (tons/yr)	DWG (tons/yr)
10,000,000	3,575,000	32,000	30,000	82,500
30,000,000	10,725,000	96,000	90,000	247,500
40,000,000	14,300,000	128,000	120,000	330,000

Notes: Ethanol capacity is denatured ethanol. Ton refers to a 2,000 lb increment or "short" ton. Typically only about 65% of the CO2 shown above is recovered and available for sale. DWG is assumed to contain 65% moisture.

North Dakota Corn Production

Figure 4 shows the nine North Dakota agricultural districts. Corn production data was obtained from the U.S. Department of Agriculture's National Agricultural Statistics Service Published Estimates Data Base. Table 19 shows the amount of corn produced in each of the nine North Dakota Agricultural Districts.

Figure 4 – North Dakota Agricultural Districts

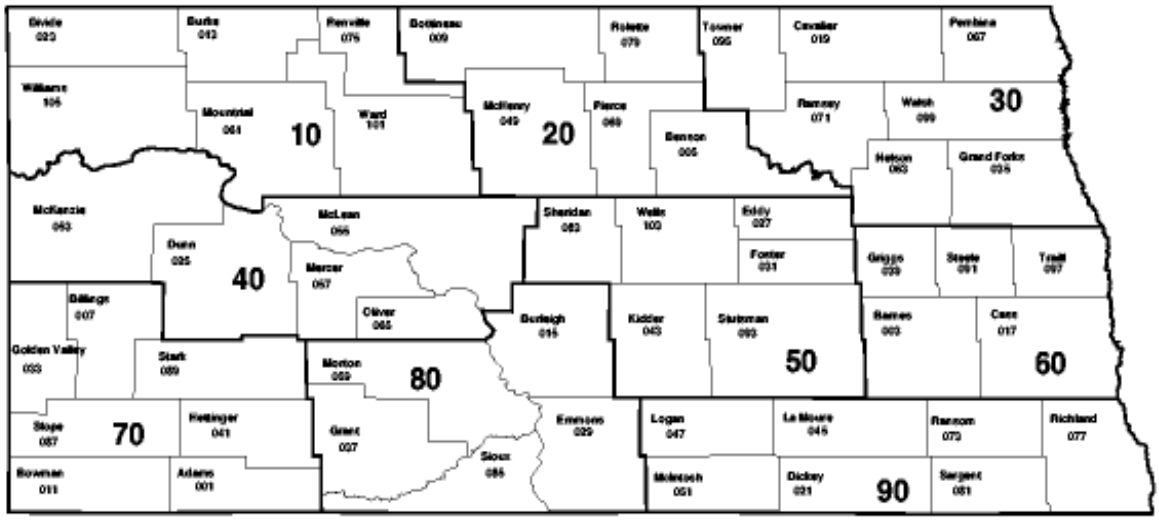


Table 19 – Corn Production in North Dakota Agricultural Districts
(2002 USDA)

District	Corn (bushels)
D10 Northwest	772,000
D20 North Central	3,940,000
D30 Northeast	9,898,000
D40 West Central	1,081,000
D50 Central	6,119,000
D60 East Central	27,075,000
D70 Southwest	750,000
D80 South Central	2,505,000
D90 Southeast	62,285,000
State Total	**114,425,000**

Nearly 78% of corn produced in North Dakota in 2002 came from Agricultural Districts 60 and 90 in the eastern portion of the state. Agricultural District 60, East Central, produced over 27 million bushels of corn in 2002. Agricultural District 90, Southeast, produced over 62 million bushels of corn during 2002, the most of any district in the state. The 89 million bushels of corn produced in Districts 60 and 90 is sufficient to generate as much as 240 MMGPY of ethanol. A 40 million gallon per year ethanol facility would utilize less than 25% of the corn produced within District 90, Southeast, in 2002.

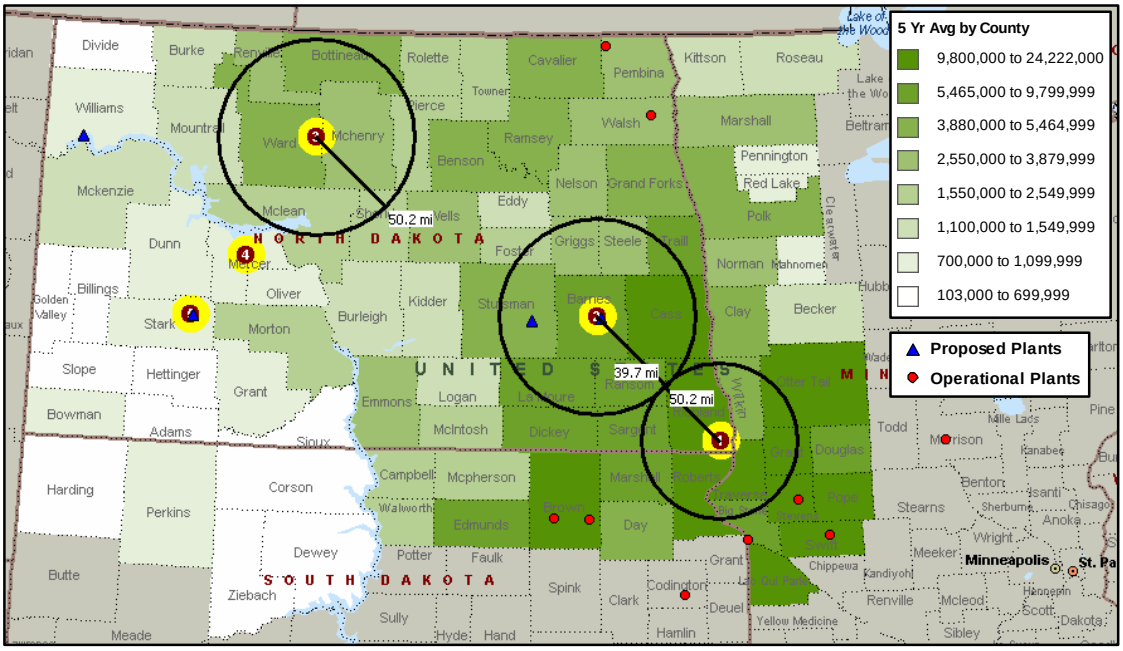
Local Corn Production

The local corn and barley production for sites #1 – #3 was previously presented in the Site Selection and Evaluation section. Sites #4 and #5 are in areas without much local grain production and corn will be railed into these plants. The results are summarized in the table below. The sites and the local feedstock areas are shown in Figure 5.

Table 20 – Annual Corn and Barley Production (bushels) Resulting Ethanol Production Potential (gallons) and Ethanol Plant Size

Plant #	Corn Production 5 Yr Avg	Corn Ethanol Potential	Barley Production 5 Yr Avg	Barley Ethanol Potential	Combined Ethanol Potential	Ethanol Plant Size (MMGPY)
Plant #1	64,843,237	45,390,266	1,550,677	852,872	46,243,139	40
Plant #2	25,546,881	17,882,817	11,464,010	6,305,206	24,188,022	30
Plant #3	1,296,879	907,815	15,874,658	8,731,062	9,638,877	10

Figure 5 – Ethanol Plant Sites with 40- and 50-mile Radius Feedstock Collection areas; bushels of combined corn and barley production



Corn may be provided from time to time from Minnesota and South Dakota and data for corn production ion these states is presented below.

Corn Production in South Dakota and Minnesota

Figure 6 shows the nine South Dakota agricultural districts.

Figure 6 – South Dakota Agricultural Districts

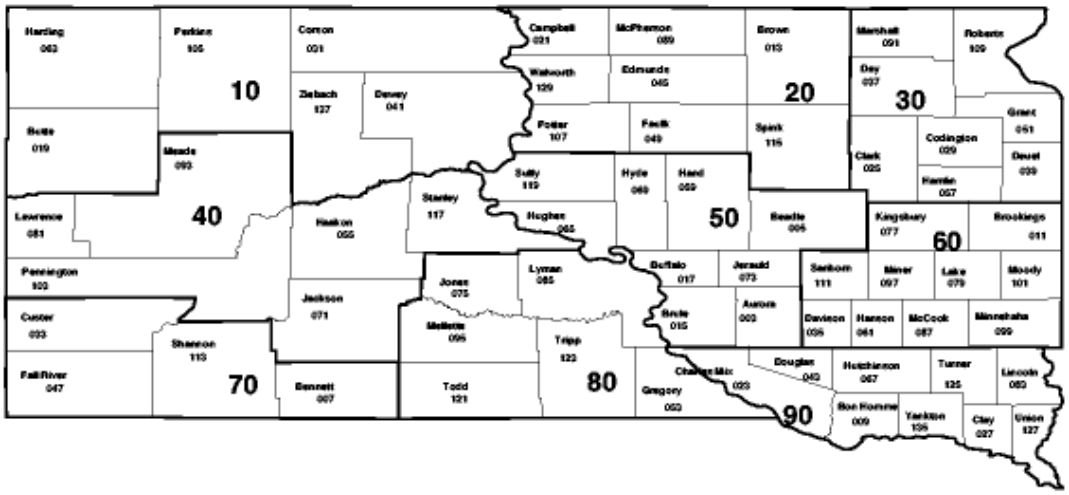


Table 21 presents corn production figures for South Dakota in 2002. Figure 7 shows the nine Minnesota agricultural districts; Table 22 presents corn production figures for Minnesota in 2002.

These data indicate there are ample supplies of corn produced in the regions east and south of North Dakota to supply a 30 or 40 MMGY ethanol plant.

Table 21 – Corn Production in South Dakota Agricultural Districts
(2002 USDA NASS)

County	Corn (bushels)
D10 Northwest	26,2000
D20 North Central	56,019,000
D30 Northeast	62,742,000
D40 West Central	115,000
D50 Central	13,696,000
D60 East Central	88,206,000
D70 Southwest	490,000
D80 South Central	3,070,000
D90 Southeast	79,400,000
State Total	**304,000,000**

Figure 7 – Minnesota Agricultural Districts

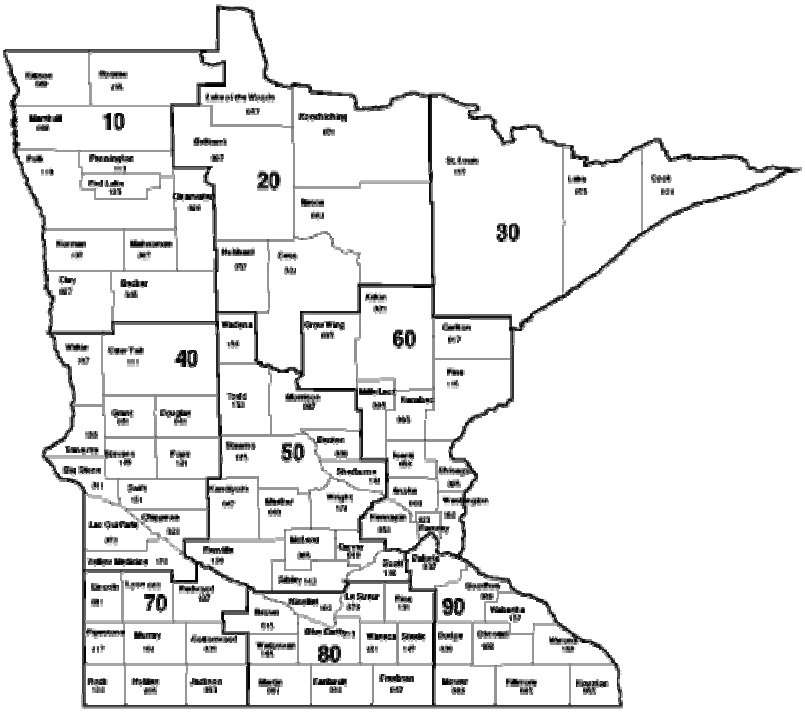


Table 22 – Corn Production in Minnesota Agricultural Districts
(2002 USDA NASS)

County	Corn (bushels)
D10 Northwest	11,762,700
D20 North Central	24,57,700
D30 Northeast	9,500
D40 West Central	202,000,000
D50 Central	201,000,000
D60 East Central	20,844,300
D70 Southwest	203,000,000
D80 South Central	253,000,000
D90 Southeast	158,000,000
State Total	**1,050,000,000**

Sources of competition for the corn feedstock required for an ethanol production facility or facilities in North Dakota would come mainly from existing ethanol production facilities in Grafton and Walhalla. There is also a corn wet mill operated by Cargill in

Wahpeton in southeast North Dakota. Several other ethanol plants are under development, but none are financed and their future is not known.

Competition can also come from local and regional feedlots, however significant competition for feedstock is not anticipated from these operations, as the DDGS co-product from the ethanol facility would correspondingly reduce the feedlots' corn requirements.

Feedstock Cost

Feedstock cost is an important issue for any ethanol plant and there are many factors that can impact the cost. One such factor is the ethanol plant's location relative to the corn supply. The plants at sites #1 – #3 are assumed to obtain feedstock locally and sites #4 and #5 are assumed to rail in corn from the corn-producing regions in southeastern North Dakota, and, depending on the delivered price of corn, may also obtain feedstock from counties in western Minnesota and northeastern South Dakota.

Statewide average corn prices from 1993 through 2002 for North Dakota, South Dakota, Minnesota, and the U.S. average are shown in Figure 8. The average corn price in North Dakota for the past ten years was $2.10 per bushel; the same figures for South Dakota and Minnesota are $2.07 and $2.13 respectively. The U.S. average corn price during the same period was $2.31 per bushel.

Table 23 presents historical corn prices for the five-state region, including North Dakota, South Dakota, Minnesota, Iowa and Nebraska from 1993-2002.

Figure 8 – Historical Corn Prices
(Source: USDA Agricultural Statistics Service and NDIC)

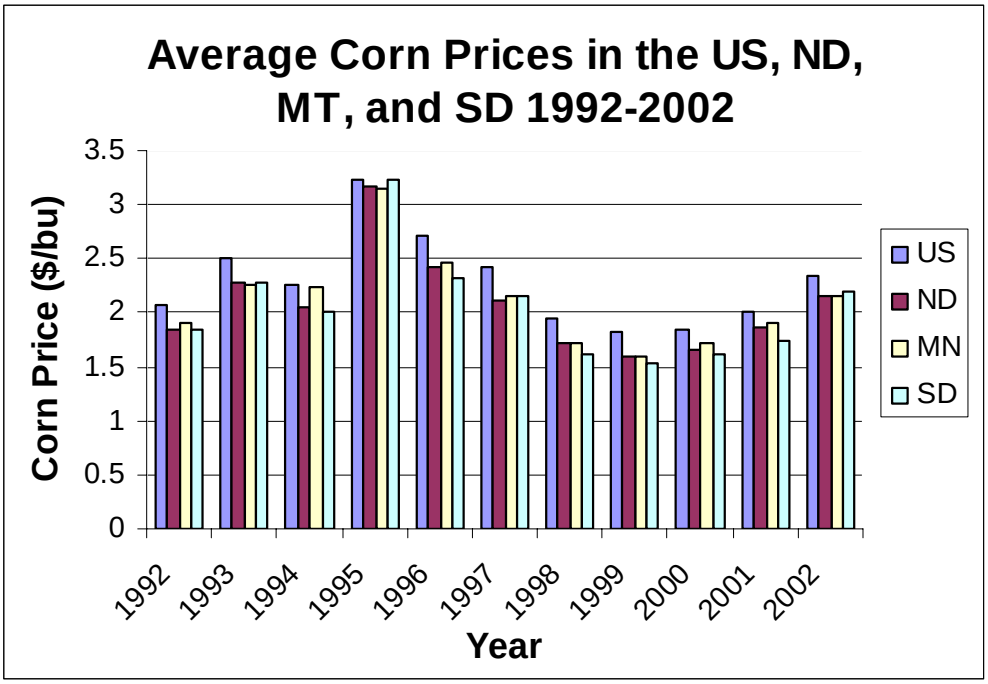


Table 23 – 5 State 10-Year Average Corn Prices

Year	US	ND	SD	MN	IA	NE
1993	2.5	2.27	2.27	2.26	2.44	2.52
1994	2.26	2.06	2.01	2.23	2.22	2.33
1995	3.24	3.16	3.23	3.14	3.2	3.22
1996	2.71	2.43	2.31	2.47	2.6	2.64
1997	2.43	2.12	2.15	2.15	2.33	2.32
1998	1.94	1.71	1.61	1.71	1.86	1.88
1999	1.82	1.59	1.54	1.6	1.72	1.75
2000	1.85	1.65	1.61	1.71	1.75	1.9
2001	2	1.87	1.75	1.9	1.9	1.94
2002	2.35	2.15	2.2	2.15	2.25	2.4
10-Yr. AVG.	2.31	**2.10**	**2.07**	**2.13**	2.23	2.29
3-State Average = 2.10						

Source: USDA Agricultural Statistics Service

North and South Dakota have historically demonstrated a lower cost for corn than the neighboring states of Minnesota, Nebraska and Iowa. The data show that among the five corn producing states within potential shuttle train distance from sites #4 and #5, Iowa and Nebraska had consistently higher prices for corn. This is a reflection of the number of ethanol plants in Iowa and Nebraska and the distance to export markets, both which contribute to drive up the local price of corn.

The price of corn in Nebraska has averaged about $0.15-$0.20 per bushel higher than in North Dakota. Corn prices in Iowa have generally tracked $0.10-$0.15 per bushel higher than North Dakota. The historical price of corn in South Dakota has historically tracked about $0.03 per bushel less than North Dakota; Minnesota corn prices have historically been about $0.03 per bushel higher than North Dakota.

Historical barley pricing for North Dakota is shown in Table 24 below. The 10-year average barley price for North Dakota is $2.02 per bushel (48 pounds per bushel). The source for grain production and pricing presented in this report is the USDA Agricultural Statistics Data Base (http://www.nass.usda.gov:81/ipedb/). The price for barley reported by the USDA is for "all barley" which includes both feed barley and malting barley.

An ethanol plant would buy feed barley, which was priced 23¢ per bushel less than the average price for all barley in North Dakota in 2001. Assuming that feed barley is typically 23¢ per bushel less than all barley, then the 10-year average for feed barley in North Dakota would be $1.79 per bushel.

Table 24 – Historical Barley Pricing & Production in North Dakota

Commodity	Year	State	Area, Yield, Production, Price per Unit, and Value of Production					
			Planted	Harvested	Yield	Production	Price per Unit	Value of production
			acres - thousand	acres - thousand	bushel	1000 bushels	dols / bu	1000 dollars
Barley All	1993	ND	2,900	2,400	49	117,600	1.69	198,744
Barley All	1994	ND	2,500	2,400	55	132,000	1.87	246,840
Barley All	1995	ND	2,300	2,250	45	101,250	2.92	295,650
Barley All	1996	ND	2,650	2,600	55	143,000	2.42	346,060
Barley All	1997	ND	2,400	2,250	45	101,250	1.96	198,450
Barley All	1998	ND	2,000	1,930	55	106,150	1.67	177,271
Barley All	1999	ND	1,350	1,240	48	59,520	1.91	113,683
Barley All	2000	ND	1,900	1,770	55	97,350	1.63	158,681
Barley All	2001	ND	1,500	1,450	55	79,750	1.70	136,373
Barley All	2002	ND	1,600	1,240	46	57,040	2.45	139,748
10-Year Average Price							**2.02**	
Barley Feed	2001	ND					1.47	
Barley Malting	2001	ND					2.03	
Feed Barley basis versus statewide average for All Barley in 2001							-0.23	
10-Year Average Price for Feed Barley using 2001 basis for Feed barley							**1.79**	

(Source: USDA Agricultural Statistics Data Base (http://www.nass.usda.gov:81/ipedb/)

Corn Shipping and Transportation Costs

Shipping corn less than 150 miles is normally most economical via truck. A good rule of thumb for estimating truck shipping rates is: the first 20 miles costs $0.06 per bushel, and for every additional 10 miles, add $0.02 per bushel. For shipping distances of 200 miles and over, economics normally favor rail shipment.

Procuring and transporting corn in large bulk quantities will result in the lowest transportation costs and lowest delivered price for corn. 110-car shuttle train shipments of corn from the southeastern region of North Dakota and western Minnesota will usually result in the lowest delivered cost for corn to sites #4 and #5. This will require the construction of rail and grain handling facilities designed for a shuttle train at the proposed sites. Approximately 8,000 feet of loop track is required for the shuttle train to be unloaded without breaking up the train. The train must be unloaded in less than 15 hours. The grain storage capacity must also be sized for the larger of the unit train capacity or at least a 10-day corn supply for the ethanol plant. A 110-car shuttle train with 4000-bushel jumbo hopper cars will deliver 440,000 bushels of corn; storage capacity for two unit trains is recommended (880,000 bushels). Some additional sections of parallel track will also need to be installed to accommodate ethanol and DDGS shipping.

To calculate feedstock costs for the proposed plant sites within North Dakota, the cost of transporting the feedstock by rail was factored in for sites #4 and #5. The freight cost for corn railed in from the southeastern North Dakota region was developed by BNSF, and is based on standard (non-shuttle) corn shipping rates. The prices developed by BNSF were checked against a second source of pricing, FC Stone. The BNSF prices and FC Stone rail freight cost estimate are shown in Table 25.

Table 25 – BNSF and FC Stone Rail Estimates for Corn

Origin	Cost/Car	Price/bushel
BNSF Rates		
Holloway, MN	$1720	$0.43
Ayr, ND	$1720	$0.43
Grebner, SD	$1780	$0.445
FC Stone Estimate		$0.40-$0.45

We will use a shipping cost of $0.43 per bushel for shipping corn to sites #4 and #5 and then adjust this shipping price down $0.10 per bushel for shuttle rates and trip and unload incentives (paid by the rail company). If we use the 10-year average price for corn in North Dakota, Minnesota and South Dakota of $2.10 per bushel, add $0.43 for shipping and subtract $0.10 for shuttle rates and incentives, the resulting delivered corn price for Richardton and Beulah is $2.43 per bushel.

The BNSF network includes 13 shuttle-train-capable grain elevators in North Dakota, 13 in South Dakota and 16 in Minnesota. These elevators are the most likely origins for grain shipments to plants in western North Dakota. The actual origin of feedstock shipments will be a factor of corn availability, local prices, and freight costs to the plant. Unfortunately, there are no shuttle unloading facilities near sites #4 and #5. The proposed plants at these sites will therefore need to include a high-speed shuttle train unloading facility as part of the site infrastructure for the financial analysis.

Historically, there has always been a positive impact on local corn prices when an ethanol plant has begun production and has created an additional local demand for product. Although difficult to predict, the typical premium paid over the local market price is usually about $0.05 per bushel after a new ethanol plant begins operation.

Grain prices used in the financial analysis for sites #1 and #2 are based on the 10-year average price of corn in North Dakota ($2.10 per bushel). The 10-year state average was adjusted for the local basis based on 2000–2001 average elevator prices provided by the North Dakota Corn Growers' Association. The basis increase for site #1 (Hankinson) versus the statewide average is estimated to be $0.15 per bushel for site #1. The basis for site #2 (Valley City) is estimated to be zero. An additional basis increase of $0.05 per bushel is also included in the estimated corn and barley prices due to increased local demand for corn or barley.

The resulting site-specific corn and barley prices used in the financial analysis are listed in the table below.

Table 26 – Location-Specific Estimated Corn Prices ($/bushel)

Site #1 Hankinson	Site #2 Valley City	Site #3 Minot	Site #4 Beulah	Site #5 Richardton
$2.28	$2.15	$1.84*	$2.43	$2.43

** The price for site # 3 is for barley; all other prices are for corn.*
Prices shown include a $0.05 per bushel increase in local basis after plant startup

Conclusions for Feedstock

There is sufficient production of corn and barley in North Dakota to supply the proposed ethanol plants. Corn would also be sourced from Minnesota and South Dakota at times when prices and freight rates favor sourcing corn from other states.

The primary competition for corn in the region will come mainly from the numerous ethanol plants located in southwestern Minnesota, eastern South Dakota, Iowa and Nebraska, all whom will be contributing to the dynamics of corn pricing in the five-state region. Based on our analysis of the available feedstock supplies in the region, significant competition is not expected from either of the two existing North Dakota ethanol plants or the Wahpeton corn wet mill.

Another source of limited competition for corn may come from local and regional feedlots in North Dakota. These operations will not pose a significant source of competition, as the projected increase in DDGS sales to the local market will help reduce or offset any challenge from these markets.

The proposed ethanol plants at sites #1 – #3 would draw feedstock from a 50-mile radius from the site and plants #4 and #5 would rail corn in from the southeastern region of North Dakota, western Minnesota and northeastern South Dakota.

V. REVIEW OF FUEL ETHANOL MARKETS

World Fuel Ethanol Industry

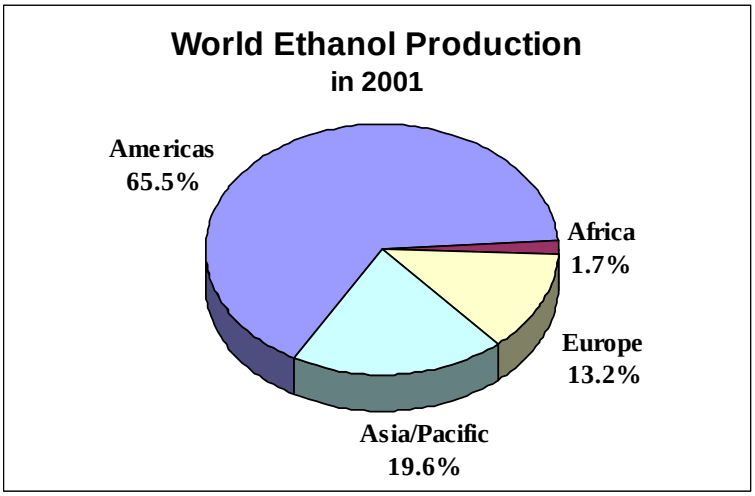
Brazil has long been the world's number one fuel alcohol producer with some three to five billion gallons of anhydrous alcohol produced each year. The United States will soon challenge this prominence due to the continuing bipartisan support for the alcohol fuel industry and the phase out of MTBE as a fuel oxygenate.

Worldwide fuel ethanol production reached approximately 8.3 billion gallons in 2001 (see Figure 9), compared to 7.9 billion gallons in 2000 and 8.2 billion gallons in 1999. The all-time high was reached in 1997, when a total of 8.7 billion gallons were produced. Even though the bulk of production still comes from Brazil and the U.S., there are significant developments in other countries as well. Some of these could result in new production centers being established beside the traditional ones in the western hemisphere.

Europe now has a major distillery built by the Ecocarburentes Group in Spain, with another one planned. The European community is also putting its weight behind the programs. There are indications that the EU is working on provisions for a Renewable Fuels Standard, securing a rising market share for biofuels. In Brazil, where some of the original fuel ethanol distilleries were using molasses and sugar cane as the raw material, expansions are also underway.

Sizeable new production centers are emerging in Thailand, where the government planned to produce up to 172 million gallons of fuel ethanol in 2003, as well as China, where recently announced projects could raise fuel ethanol production capacity to 536 million gallons a year.

Figure 9 – Worldwide Ethanol Production by Continent

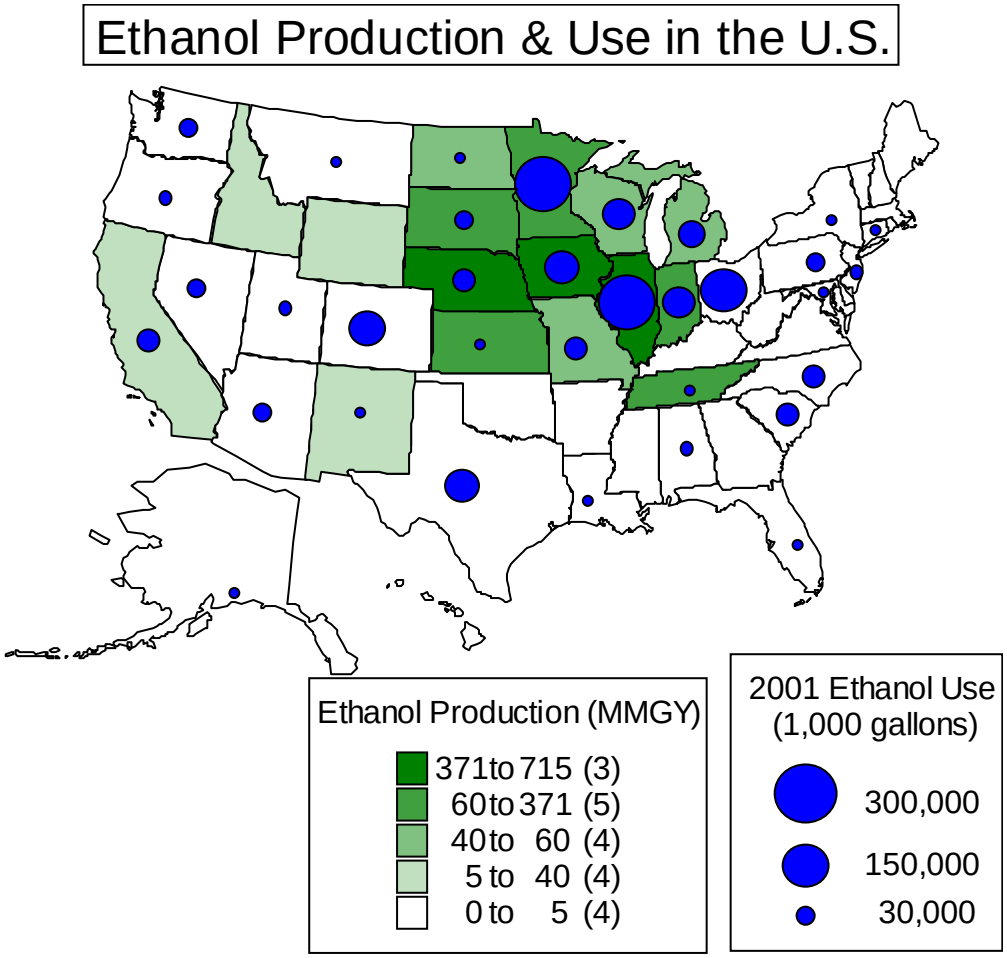


(Source: F.O. Licht)

U.S. Ethanol Industry

Currently there are 74 commercial fermentation ethanol production facilities in the United States with 14 new plants under construction. Fuel ethanol production capacity in the United States has just recently exceeded three billion gallons annually. Capacity under construction is 360 million annual gallons. Approximately 95% of U.S. fuel ethanol is manufactured from corn and it follows that the majority of production capacity and subsequent use of fuel ethanol is in the Midwest Corn Belt. Ethanol is used in nearly every state in the country including Alaska (see Figure 10).

Figure 10 – U.S. Ethanol Production and Use



In the U.S., ethanol's primary purpose is to serve as an octane extender for gasoline, a clean air additive in the form of an oxygenate, and as an aid in the reduction of America's dependence on imported oil, thereby reducing our balance of trade. In order to accomplish these tasks in the face of resistance from the oil industry, Congress established an incentive in the form of a tax credit during the mid-1970's designed to encourage the oil industry to blend ethanol. The tax incentive continues today and was recently extended to 2007; the Congress is currently considering a further extension

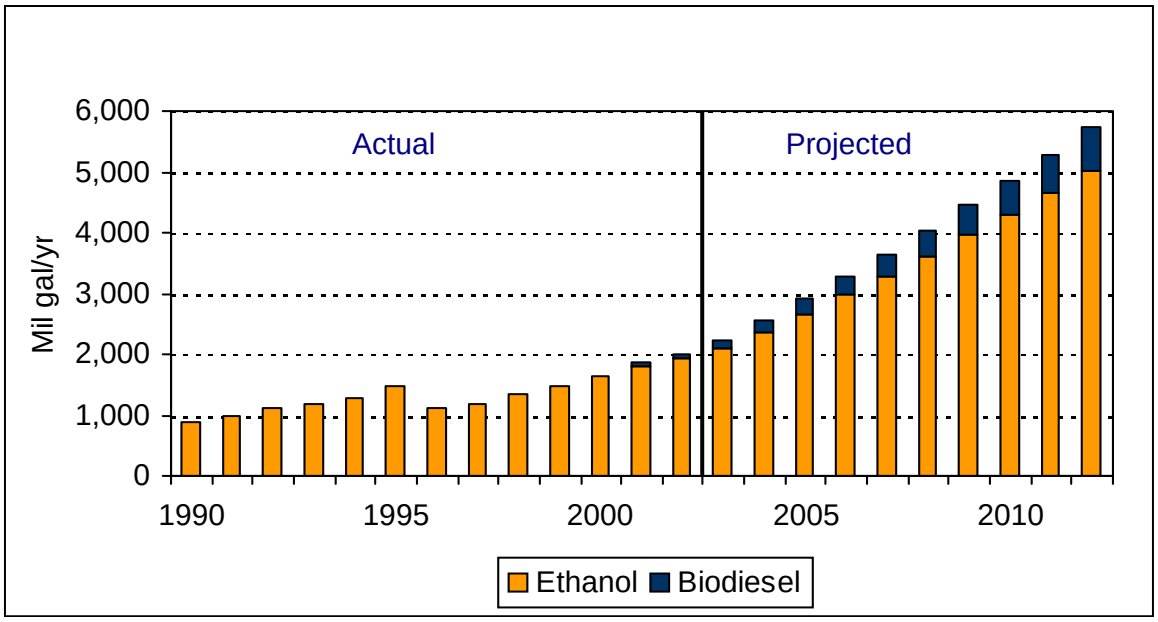
through 2010. It is BBI's opinion that the federal tax incentive will be extended at least through 2010.

New restrictions on automobile emissions, reductions in carbon monoxide, smog mitigation programs in major cities, and a general trend toward the reduction of greenhouse gas emissions, continue to drive the demand for ethanol. Discoveries of ground water contamination by methyl tertiary butyl ether (MTBE), ethanol's primary competitor, have spurred even greater interest in ethanol blends.

The refining capacity in the United States continues to decline while gasoline consumption continues to increase. The slightest upset in refining capacity (fire, shutdown, closure) sends gasoline prices soaring. U.S. refining capacity is not keeping pace with increasing demand. Ethanol plays a key role in helping refiners extend their product by as much as 10%.

As shown in Figure 11, ethanol demand is expected to increase at a very aggressive pace with current market, environmental and political forces all driving demand for ethanol and other renewable fuels higher. Today's three billion gallon per year production capacity is expected to grow to at least five billion gallons by the year 2010. If the use of MTBE is phased out on a national level and the RFG oxygenate requirement remains unchanged, the projected increase in ethanol demand could occur much sooner.

Figure 11 – Projected Renewable Fuels Growth in the U.S.



(Source: AUS Consultants)

As of this writing, legislation calling for a Renewable Fuel Standard (RFS, is being deliberated in the U.S. Senate as part of national energy and transportation legislative proposals. Legislation under consideration would establish a national RFS reaching five

billion gallons in 2012, potentially ban MTBE nationwide, eliminate the reformulated gasoline oxygenate standard, and enhance air quality protections.

Market Overview

The primary market drivers for fuel ethanol in the U.S. are octane requirements and oxygen requirements as well as toxic air reductions. For new ethanol projects, ethanol markets should be divided up into three categories: local, regional, and national.

One of the most important marketing decisions to be made will be the allocation of production to the various markets. If too much product is sold locally, the local price will be depressed. If too much is sold regionally or nationally, transportation costs will be increased and opportunities to service a less expensive local market will be forgone. A good balance between local, regional and national markets are required to achieve a maximum revenue return to the plant.

Local Ethanol Markets

Several different sources were researched to generate an estimate of fuel ethanol use in North Dakota. While data from the different sources varied slightly, annual consumption in North Dakota is low, averaging just under six million gallons per year over the period 1997-2002. Data for 1997-2002 from the Federal Highway Administration of the US DOT are shown in Table 27. Based on the data from FHA, fuel ethanol consumption averaged 5.97 million gallons per year for the period 1997-2002.

Table 27 – North Dakota Ethanol Consumption Estimates for the Years 1997-2002
(Source: DOT-FHA)

Ethanol Used in Gasohol in ND	
Year	**Gallons**
1997	5,282,000
1998	4,546,000
1999	4,630,000
2000	5,577,000
2001	6,698,000
2002	8,897,100
Average	**5,938,350**

Table 28 compares the DOT data on ethanol use for 2002 with an estimate of the total market potential in North Dakota based on gasoline consumption.

Table 28 – Gasoline Consumption & Market Potential for E-10 in North Dakota (2002)

Gasoline	Etoh Potential	EtOH Actual	% Penetration
366,491,000	36,649,100	8,897,100	24.3%

The data indicate that ethanol use in gasoline has penetrated just 24.3 % of the market in North Dakota. The existing ethanol production capacity in the state is 38.5 MMGPY (see Table 29) with another 30 MMGPY under development (Dakota Renewable Fuels has announced plans to build a 30 MMGY ethanol plant in the southeast part of the state). Even at 100% market penetration, which is extremely unlikely, statewide capacity exceeds the size of the potential market.

Table 29 – Existing Ethanol Production Facilities in North Dakota

Company	Location	State	Feedstock	Capacity (MMGY)
Alchem LLP	Grafton	ND	Corn	10.5
Archer Daniels Midland	Walhalla	ND	Corn	28

The fact that existing production capacity exceeds the local market potential means that a new facility in North Dakota would need to market virtually all their production to regional or national outlets.

Regional Ethanol Markets

The regional market is one that is outside of the immediate local market, yet is within the state as well as neighboring states. This market will likely be serviced by rail, and is within a 450-mile radius of the plant. For the current study, this includes counties within South Dakota, Minnesota, Nebraska, Iowa, Montana, Wyoming, and Colorado in the US, and parts of the provinces of Alberta, Saskatchewan and Manitoba in Canada.

The regional markets for ethanol plants in North Dakota would include the metropolitan areas of Minneapolis, Omaha, Sioux Falls, and potentially Des Moines and Denver in the US, and the cities of Winnipeg, Regina and potentially Calgary in Canada. Ethanol use in North Dakota and the states and provinces within a 450-mile radius is shown in Table 30 below. Ethanol use in the regional market was nearly 500 million gallons in 2002. Regional pricing tends to follow national pricing less the freight difference. As with national markets, the use of an ethanol marketing company is advantageous, especially in the first one to three years of operation.

The data in Table 30 demonstrate that regional market penetration is generally highest in states with significant ethanol production capacity, with Minnesota nearing 95% of saturation. A similar situation is seen in Iowa (58%), South Dakota (51%) and Nebraska (37%). Colorado has seen a significant increase in fuel ethanol consumption due to the mandated use of ethanol for air pollution mitigation.

Due to the concentration of ethanol production facilities in the upper US Midwest, and the near absence of ethanol production facilities in the regions to the west and north, a plant in North Dakota should utilize its advantageous location and focus on marketing its production to regional markets to the west (Montana, the Pacific Northwest and

California) and north (Alberta, Saskatchewan, Manitoba). Based on the difference between ethanol use and ethanol potential in Table 30, there is an untapped market potential of over 600 MMGPY, more than adequate to absorb the output from one or more 40 MMGPY facilities in North Dakota.

Table 30 – Gasoline Use, Ethanol Use and E-10 Market Potential in North Dakota and Neighboring States and Provinces in 2002 (gallons)

State	Gasoline	EtOh Potential	EtOH Actual	% Penetration
ND	366,491,000	36,649,100	8,897,100	24.3
SD	455,689,000	45,568,900	23,104,500	50.7
MN	2,726,586,000	272,658,600	258,720,000	94.9
NE	888,558,000	88,855,800	32,584,500	36.7
IA	1,616,809,000	161,680,900	93,427,000	57.8
WY	353,757,000	35,375,700	NA	NA
MT	509,178,000	50,917,800	1,645,000	3.2
CO	2,105,567,000	210,556,700	74,061,000	35.2
8-State Total	**9,022,635,000**	**902,263,500**	**492,439,100**	**54.6**
Alberta	1,333,976,222	133,397,622	NA	NA
Saskatchewan	403,830,647	40,383,065	NA	NA
Manitoba	411,604,756	41,160,476	NA	NA
3 Province Total (See Note 1)	**2,149,411,625**	**214,941,162**	**63,408,190**	**29.5**

(Note 1: Data on provincial ethanol consumption was unavailable. Market penetration was calculated based on total current Canadian production capacity of 63.4 MMGY.)
Sources: DOE-EIA and U.S. Federal Highway Administration Statistics 2002
Statistics Canada, The Canadian Renewable Fuels Association

National Ethanol Markets

California has been the focus of a major ethanol campaign as MTBE has now been phased out. California delayed the ban on the use of MTBE from January 1, 2003, to January 1, 2004, but has now completed the transition. California represents a market of about *700 million gallons* annually due to the oxygenate requirement for RFG. Due to the phase out of MTBE, the California market has shown substantial growth.

One driving force for this continued change over from MTBE is possibly the pending class action suite filed against those companies that continue to blend MTBE despite the government warning of its use. Despite these resistances, the California ethanol market could approach one billion gallons per year if the oil and pipeline companies agree to use essentially the same gasoline blend stock throughout the state.

While there is a great deal of focus on California, another emerging ethanol market is in the Northeast. As in California, the primary drivers are the health and water concerns surrounding the use of MTBE. The market potential for ethanol in the Northeast is estimated at about one billion gallons annually. The ultimate size of the California and Northeast markets will depend on how the RFG oxygenate and MTBE debate plays out in the political arena.

Other significant national ethanol market opportunities are developing in areas such as the Pacific Northwest, and the US Southwest, including Texas, Arizona, Nevada and New Mexico.

It is probably in the best interests of plants in North Dakota to move product into national markets that are to the north and west, where adequate markets exist for the anticipated production from facilities in North Dakota. A listing of select national markets with estimates of the market demand is provided in Table 31

The data in Table 31 show that market penetration in the western states is generally low, although ethanol use has increased significantly over previous years. Currently, Oregon, Washington and Nevada lead the region with market penetration approaching 25% of the potential market. Combining the prospective markets in the Pacific Northwest, California, Utah and the Southwest creates a potential market of nearly four billion gallons of ethanol. Considering the scale of the market, one or more 40 MMGPY ethanol plants in North Dakota should have no problem finding markets for the ethanol product.

Table 31 – Select National Ethanol Market Estimates Use of Gasohol

State	Gasoline	EtOh Potential	EtOH Actual	% Penetration
CA	15,698,946,000	1,569,894,600	177,361,000	11.3
OR	1,572,294,000	157,229,400	38,629,000	24.6
WA	2,759,840,000	275,984,000	65,824,000	23.9
AZ	2,605,332,000	260,533,200	14,977,000	5.7
NV	1,004,110,000	100,411,000	24,655,000	24.6
ID	667,739,000	66,773,900	NA	NA
UT	1,038,233,000	103,823,300	5,026,100	4.8
NM	951,611,000	95,161,100	8,398,700	8.8
TX	11,410,393,000	1,141,039,300	32,552,000	2.9
9-State Total	**37,708,498,000**	**3,770,849,800**	**367,422,800**	**9.7**
British Columbia (See Note 1)	1,247,668,692	124,766,869	NA	NA

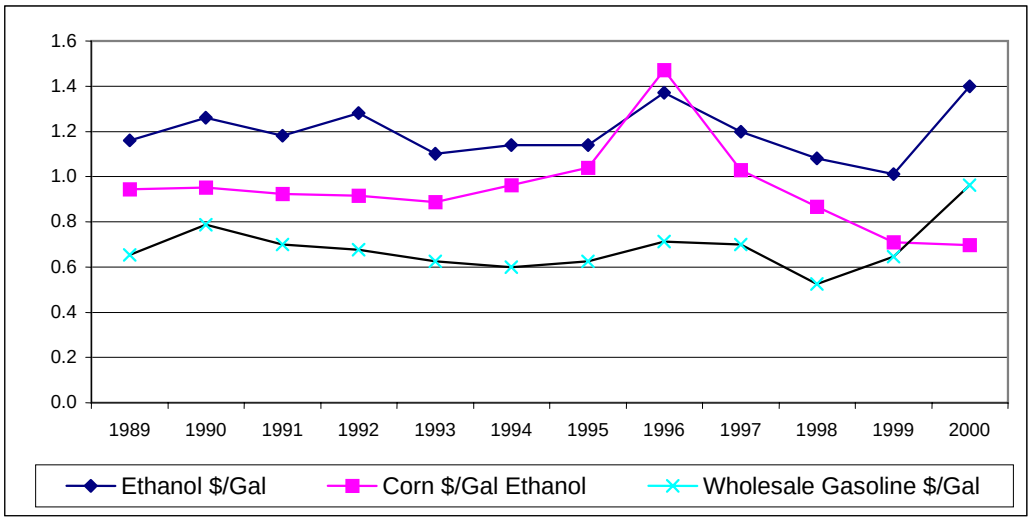
Sources: U.S. Department of Transportation Highway Statistics 2002, Statistics Canada
Note 1: Estimate based on 10% of gasoline consumption.

Ethanol Pricing

Ethanol prices in the US are based on the wholesale gasoline price plus the federal tax incentive of 52¢ per gallon. The tax incentive credit is usually taken by the blender, and passed through to the producer in the form of an additional $0.52/gal on the ethanol producer's selling price. The blender will avoid paying $0.052 in tax per gallon of blended E-10, which he can then pay to the producer at a rate of $0.52/gal of denatured ethanol.

Historical U.S. average ethanol, corn and gasoline prices for the period 1989-2000 are shown in Figure 12.

Figure 12 – Average US Market Pricing of Ethanol, Gasoline and Corn



Wholesale Gasoline Data Source: DOE U.S. Refiner Prices of Petroleum Products for Resale
Corn Data Source: USDA. Prepared by BBI International.

The average ethanol price in the Minneapolis and Fargo markets from January 1990 through September of 2002 was $1.23 and $1.22 per gallon, respectively. The average ethanol price for selected Regional and West Coast markets over the last 10 years is provided below in Table 32.

Based on a review of local, regional, and national markets available to a plant, or plants, in North Dakota, the ethanol price used in the financial analysis will be a weighted value reflecting the price of ethanol across the anticipated markets.

The projected selling price for the ethanol product was calculated based on the proposed marketing and distribution plan (see below under Ethanol Market Summary). The historical prices of ethanol in local, regional and national markets were established and then a weighted value representing a hybrid ethanol price was computed based on the percentage of ethanol marketed to the respective markets. The weighted price of ethanol used in the financial analysis was $1.27 per gallon of denatured ethanol (Table 33).

Table 32 – 10-Year Average Ethanol Price in Select Regional and National Markets

Market	Ethanol Price ($/gal)
Los Angeles	$1.269
San Francisco	$1.273
Phoenix	$1.267
Albuquerque	$1.259
Las Vegas	$1.284
Denver	$1.269
Boise	$1.251
Portland	$1.286
Seattle	$1.275
Average	**$1.270**

Table 33 – Weighted Average Ethanol Selling Price

Destination	Average Ethanol Price	% of Market	Weighted Cost/Gal
Local (truck)	$1.23	5%	$0.062
Regional	$1.25	25%	$0.313
PNW (WA, OR)	$1.28	35%	$0.448
CA, AZ, NV	$1.27	35%	$0.445
		100%	$1.267

State Producer Payment

North Dakota's ethanol production incentive program is administered by the Agricultural Product Utilization Division in the Department of Commerce. The program is funded by the legislature on a biennium cycle and funding for the incentive amount for the period July 1, 2003, to June 30, 2005, is $0.40 per gallon. After June 31, 2005, the incentive amounts will be calculated based on the price per bushel of corn and the price per gallon of ethanol. The program was changed substantially by SB 2222 of the 2003 legislative session.

For new ethanol plants, the incentive amount is calculated based on the price per bushel of corn and the price per gallon of ethanol. The price per bushel of corn is based on the average North Dakota price per bushel of corn received by farmers during the quarter, as established by the North Dakota agricultural statistics service and the average North Dakota rack price per gallon of ethanol during the quarter, as compiled by the American Coalition for Ethanol.

Eligible facilities are defined as ethanol production plants constructed in North Dakota after July 31, 2003. For incentive amounts calculated based on the price per bushel of corn and the price per gallon of ethanol, the Agricultural Product Utilization Commission may not distribute more than $1,600,000 annually in total payments. An eligible facility

may not receive payments under the program that exceed a total of $10,000,000. Change of ownership of an eligible facility does not affect the $10,000,000 cumulative total allowed.

The payments for new ethanol plants are based on a counter cyclical mechanism that pays the plant 1/10th of a cent per gallon of ethanol produced for every 1 cent that corn is above $1.80 per bushel and 2/10th of a cent per gallon of ethanol for every 1 cent that ethanol goes below $1.30 per gallon. In addition, for every 1 cent that corn is below $1.80 there will be a deduction of 1/10th cent per gallon from the payment and for every 1 cent that ethanol is above $1.30 per gallon there will be a 2/10th cent per gallon deduction from the payment. At $1.80 corn and at $1.30 ethanol there are no payments and no deductions. Payments cannot exceed $1.6 million per year statewide and $10 million over the life of the plant.

Using the 10-year average price of corn in North Dakota of $2.10 per bushel and an average rack price for ethanol of $1.25, results in the following incentive amount:

$$0.1 \times (2.10-1.80) + 0.2 \times (1.30-1.25) = \$0.04 \text{ per gallon of ethanol}$$

The annual payment to an ethanol producer will depend upon the number of new ethanol plants built in North Dakota. If there is only one new 40 MMGPY plant in the state, it could qualify for the entire $1.6 million annual allocation. If there are several new plants built, then the payments would be prorated amongst the plants. We will assume that four plants are built and the payments to each plant are limited to $400,000 per year per plant.

For existing ethanol plants, the incentive amount is $0.40 per gallon. An ethanol plant in operation before July 1, 1995, with production capacity of fewer than 15 million gallons of ethanol, may receive up to $600,000 per fiscal year. An ethanol plant that was in operation before July 1, 1995, and which produced 15 million or more gallons in the previous fiscal year, is eligible to receive up to $300,000 in production incentives per fiscal year. For additional information contact:

John Schneider
North Dakota Commerce Department
Agricultural Product Utilization Division
400 East Broadway, Suite 50
PO Box 2057
Bismarck, ND 58502-2057
Phone: (701) 328-5350
Fax: (701) 328-5320
E-Mail: jfschneider@state.nd.us
Web site: http://www.ndcommerce.com/index.html

Ethanol Transportation Costs

Transportation costs for the ethanol product were calculated based on the proposed marketing and distribution plan (see below under Ethanol Market Summary). Costs to local, regional and national markets were estimated based on quotes obtained from BNSF. Then a weighted value for shipping cost was computed based on the percentage of ethanol marketed to the respective markets. The development of the weighted transportation cost is shown in Table 34.

Table 34 – Ethanol Regional and National Shipping Costs

Destination	Cost/Car	Cost/Gal	% of Market	Weighted Cost/Gal
Local (truck)	4 hr x $60/hr/8,000 gal	$0.030	5%	$ 0.002
Regional	$2,300	$0.076	25%	$ 0.019
PNW (WA, OR)	$2,900	$0.096	35%	$ 0.034
CA, AZ, NV	$3,650	$0.121	35%	$ 0.042
			100%	$0.097

The weighted transportation cost used in the financial analysis will be $0.097 per gallon. This value is nearly double the normal value ($0.06/gal) and reflects the need to market a higher percentage of ethanol to regional and national markets.

Ethanol Market Summary

The ability to divide product effectively between local, regional and national markets is extremely important. So much so, that it is imperative that an experienced ethanol marketing company be hired to broker the plant's ethanol. A typical market division for an ethanol facility would be to sell no more than 50% of the ethanol into the local market, 30% into the regional market, and 20% into the national market.

The best scenario for an ethanol plant in North Dakota would be to focus marketing its ethanol production to regional outlets to the west and north, and national outlets on the West Coast. The plant should seek to market approximately 30% of its production locally and regionally in states and provinces to the north and west, including Montana, Idaho, and potentially Colorado in the US and Alberta, Saskatchewan and Manitoba in Canada. The plant should seek to market the balance of its product (70%) on the West Coast, focusing on markets in Northern California, Oregon, Washington, and potentially British Columbia where the plant would enjoy a distinct advantage over Midwest ethanol facilities. The proposed projects would be at a strong disadvantage if it sought to market product to the east or southeast due to the significant amount of ethanol produced in the central and northern Midwest states of Iowa, Illinois, Minnesota Nebraska and Kansas.

For the proposed North Dakota facility(s), BBI anticipates marketing less than 5% of the product to local markets, approximately 25% to regional markets, with 70% of the product being shipped to national markets in California and the Pacific Northwest. The actual marketing plan will depend on the ethanol marketing firm selected for the project.

In the future, an opportunity may develop to replace current Midwest regional market demand if the major producers such as ADM and Williams shift their marketing efforts to supplying California and the Northeast. This may develop into an opportunity to ship ethanol to Midwest markets.

Ethanol pricing has been, and will likely continue to be very volatile. Spot ethanol prices in the Minneapolis market have ranged from 92¢ to $1.73 per gallon over a 10-year period; in San Francisco, the price of ethanol has ranged from 92¢ to $1.77 per gallon over the same period and in Seattle the comparable range has been from 93¢ to $1.73 per gallon. A price of $1.27 per gallon of denatured ethanol, and a transportation cost of $0.097 per gallon, will be used in the financial analysis.

VI. REVIEW OF CO-PRODUCTS

Distillers Dried Grains with Solubles

Distillers grains are the residues that remain after high quality cereal grains have been fermented by yeast. In the fermentation process, nearly all of the starch in the grain is converted to ethanol and carbon dioxide, while the remaining nutrients (proteins, fats, minerals and vitamins) undergo a three-fold concentration to yield *distillers wet grains* (DWG). Adding evaporator syrup and drying the material to 10% moisture creates *distillers dried grains with solubles* (DDGS). The addition of the soluble fraction increases the protein and vitamin potency of the final product and also provides a solid baseline byproduct that can be marketed while allowing development of both the wet feed and special blend feed markets. DDGS is the most common and highest volume form of feed product derived from a dry mill facility. The composition of typical DDGS produced via dry mill ethanol technology is provided in Table 35.

Table 35 – Typical Corn DDGS Composition

Component	Weight %
Moisture	9 to 10%
Protein	27 to 30%
Fat	7.5 to 9%
Fiber	8 to 9%
Ash	4.5 to 5%

DDGS derived from corn contains nutrients that have been demonstrated by numerous studies to have important growth promoting properties for dairy and beef cattle, poultry and swine. For dairy cattle, the high digestibility and net energy content of DDGS and DWG, compared to other feed ingredients (soybean meal, canola meal, brewers spent grains as examples), as well as its high fat content, results in feeds that yield greater milk production. For beef cattle the improved rumen health, energy effect of the fiber, and palatability has been shown in feedlot studies to result in faster and more efficient gains.

Four million tons of DDGS are produced in North America each year and incorporated into animal feeds or exported. Several ethanol producers market a portion of their byproducts in a wet form (65% moisture) where nearby markets make it economical to deliver the product and avoid drying costs. Some maintain that DWG has a higher nutritive value than DDGS due to degradation of the protein and loss of some volatile compounds during drying of the DDGS.

Local Market for Distillers Grain

Approximately 18 pounds of distillers dried grains and solubles (DDGS) are produced from each bushel of corn or barley processed. A 40 MMGPY ethanol plant will therefore produce about 129,000 tons of DDGS annually; a 30 MMGPY plant will generate about 96,000 tons and a 10 MMGPY plant will generate about 32,000 tons of DDGS annually.

Feeder cattle will typically consume between 4 and 8 pounds of DDGS per day depending upon the ration prescribed by the owner or the owner's nutritionist. Four pounds of DDGS per day is equivalent to ¾ tons per year and eight pounds per day is equivalent to 1.5 tons per year. We will assume one ton per year per cow for estimating the DDGS market size required for each ethanol plant.

At a rate of one ton of DDGS per cow per year (6 pounds per day), approximately 129,000 head of cattle are required for the DDGS output of a 40 million gallon per year dry mill ethanol facility, 96,000 head for a 30 MMGPY plant, and 32,000 head are required to utilize the DDGS generated from a 10 MMGY plant.

The DDGS production for each ethanol plant and the number of cattle within a local market radius for each site is shown in the map below. We have defined the "local DDGS market" to be the area within 100 miles of the 40 MMGPY plants, 75 miles for the 30 MMGPY plant, and 30 miles for the 10 MMGPY plant. The number of cattle within each local DDGS market is shown in the following tables for each site.

Figure 13 – Cattle Inventory in North Dakota and Local DDGS Markets

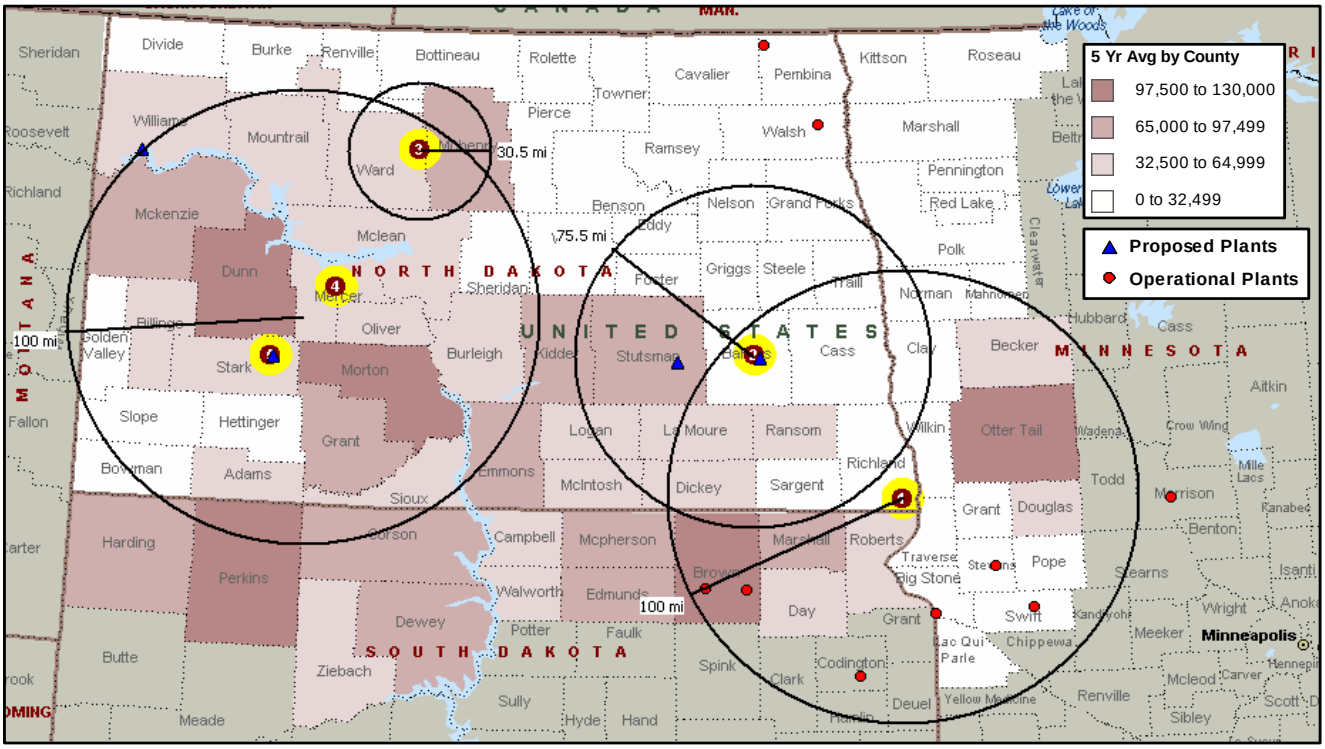


Table 36 – Cattle Inventory within 100 miles of Site #1

County	State	1998	1999	2000	2001	2002	5-Year Avg.
Becker	MN	36,900	37,000	39,000	38,000	35,500	**37,280**
Big Stone	MN	8,700	9,000	9,000	9,000	9,000	**8,940**
Chippewa	MN	7,400	7,500	8,000	8,000	8,000	**7,780**
Clay	MN	18,600	18,500	19,500	20,000	19,500	**19,220**
Douglas	MN	32,500	33,000	34,000	34,000	34,000	**33,500**
Grant	MN	7,800	7,500	8,000	8,500	8,500	**8,060**
Hubbard	MN	10,800	11,000	11,200	11,700	11,400	**11,220**
Kandiyohi	MN	28,000	28,000	28,500	28,500	29,500	**28,500**
Lac Qui Parle	MN	16,200	16,000	15,500	15,500	15,500	**15,740**
Mahnomen	MN	13,300	13,200	13,000	13,000	12,500	**13,000**
Norman	MN	12,000	11,800	11,000	11,000	10,000	**11,160**
Otter Tail	MN	108,000	107,000	108,000	108,000	111,000	**108,400**
Pope	MN	32,400	31,000	32,500	33,000	32,500	**32,280**
Stearns	MN	175,000	179,000	183,500	186,000	188,500	**182,400**
Stevens	MN	24,400	24,000	26,000	26,500	27,000	**25,580**
Swift	MN	19,000	19,000	20,000	20,500	21,500	**20,000**
Todd	MN	68,400	70,000	71,500	71,500	73,000	**70,880**
Traverse	MN	7,300	7,000	8,000	8,000	8,000	**7,660**
Wadena	MN	25,700	25,500	25,000	25,000	24,000	**25,040**
Wilkin	MN	5,000	4,500	5,000	5,000	5,000	**4,900**
Yellow Medicine	MN	22,500	21,500	23,000	24,000	24,000	**23,000**
Barnes	ND	27,000	23,000	24,000	32,000	26,000	**26,400**
Cass	ND	20,000	20,000	20,000	20,000	19,000	**19,800**
Dickey	ND	43,000	41,000	45,000	46,000	45,000	**44,000**
La Moure	ND	35,000	33,000	28,000	39,000	34,000	**33,800**
Ransom	ND	33,000	33,000	32,000	35,000	31,000	**32,800**
Richland	ND	31,000	27,000	28,000	33,000	33,000	**30,400**
Sargent	ND	27,000	32,000	28,000	28,000	26,000	**28,200**
Steele	ND	7,000	7,000	8,000	9,000	8,000	**7,800**
Stutsman	ND	67,000	67,000	64,000	66,000	61,000	**65,000**
Trail	ND	5,000	5,000	4,000	5,000	7,000	**5,200**
Brown	SD			105,000	109,000	89,000	**101,000**
Clark	SD			65,000	68,000	63,000	**65,333**
Codington	SD			53,000	54,000	57,000	**54,667**
Day	SD			44,000	45,000	48,000	**45,667**
Deuel	SD			49,000	52,000	44,000	**48,333**
Grant	SD			43,000	44,000	48,000	**45,000**
Hamlin	SD			34,000	33,000	34,000	**33,667**
Marshall	SD			75,000	77,000	73,000	**75,000**
McPherson	SD			78,000	82,000	80,000	**80,000**
Roberts	SD			51,000	52,000	53,000	**52,000**
Spink	SD			85,000	91,000	91,000	**89,000**
Total							**1,677,607**

Source: http://www.usda.gov/nass; 1998 - 2002, all cattle inventory

Table 37 – Cattle Inventory within 75 miles of Site #2

County	State	1998	1999	2000	2001	2002	5-Year Avg.
Clay	MN	18,600	18,500	19,500	20,000	19,500	**19,220**
Norman	MN	12,000	11,800	11,000	11,000	10,000	**11,160**
Polk	MN	27,700	28,800	28,500	27,000	27,000	**27,800**
Wilkin	MN	5,000	4,500	5,000	5,000	5,000	**4,900**
Barnes	ND	27,000	23,000	24,000	32,000	26,000	**26,400**
Benson	ND	33,000	31,000	28,000	35,000	30,000	**31,400**
Cass	ND	20,000	20,000	20,000	20,000	19,000	**19,800**
Dickey	ND	43,000	41,000	45,000	46,000	45,000	**44,000**
Eddy	ND	22,000	19,000	17,000	18,000	19,000	**19,000**
Foster	ND	15,000	23,000	18,000	22,000	17,000	**19,000**
Grand Forks	ND	16,000	15,000	15,000	20,000	23,000	**17,800**
Griggs	ND	16,000	20,000	19,000	19,000	20,000	**18,800**
Kidder	ND	72,000	72,000	74,000	73,000	76,000	**73,400**
La Moure	ND	35,000	33,000	28,000	39,000	34,000	**33,800**
Logan	ND	50,000	53,000	49,000	59,000	53,000	**52,800**
McIntosh	ND	41,000	46,000	45,000	45,000	43,000	**44,000**
Nelson	ND	13,000	13,000	15,000	15,000	13,000	**13,800**
Ramsey	ND	6,000	7,000	7,000	7,000	6,000	**6,600**
Ransom	ND	33,000	33,000	32,000	35,000	31,000	**32,800**
Richland	ND	31,000	27,000	28,000	33,000	33,000	**30,400**
Sargent	ND	27,000	32,000	28,000	28,000	26,000	**28,200**
Steele	ND	7,000	7,000	8,000	9,000	8,000	**7,800**
Stutsman	ND	67,000	67,000	64,000	66,000	61,000	**65,000**
Trail	ND	5,000	5,000	4,000	5,000	7,000	**5,200**
Wells	ND	26,000	29,000	24,000	27,000	26,000	**26,400**
Brown	SD			105,000	109,000	89,000	**101,000**
Marshall	SD			75,000	77,000	73,000	**75,000**
Total							**855,480**

Source: http://www.usda.gov/nass; 1998 - 2002, all cattle inventory

Table 38 – Cattle Inventory within 30 miles of Site #3

County	State	1998	1999	2000	2001	2002	5-Year Avg.
Bottineau	ND	19,000	24,000	21,000	24,000	22,000	**22,000**
McHenry	ND	72,000	82,000	78,000	83,000	86,000	**80,200**
Mclean	ND	43,000	48,000	46,000	53,000	51,000	**48,200**
Renville	ND	8,000	9,000	8,000	7,000	7,000	**7,800**
Ward	ND	42,000	41,000	47,000	53,000	47,000	**46,000**
Total							**204,200**

Source: http://www.usda.gov/nass; 1998 - 2002, all cattle inventory

Table 39 – Cattle Inventory within 100 miles of Sites #4 and #5

County	State	1998	1999	2000	2001	2002	5-Year Avg.
Richland	MT	56,000	58,000	62,000	61,000	66,000	**60,600**
Wibaux	MT	18,500	20,500	19,900	21,000	20,000	**19,980**
Adams	ND	38,000	27,000	38,000	36,000	36,000	**35,000**
Billings	ND	33,000	38,000	36,000	34,000	41,000	**36,400**
Bottineau	ND	19,000	24,000	21,000	24,000	22,000	**22,000**
Bowman	ND	32,000	35,000	27,000	27,000	35,000	**31,200**
Burke	ND	13,000	17,000	13,000	15,000	18,000	**15,200**
Burleigh	ND	58,000	66,000	67,000	63,000	67,000	**64,200**
Dunn	ND	92,000	95,000	97,000	106,000	99,000	**97,800**
Emmons	ND	71,000	74,000	65,000	70,000	68,000	**69,600**
Golden Valley	ND	27,000	30,000	27,000	21,000	21,000	**25,200**
Grant	ND	65,000	67,000	65,000	75,000	80,000	**70,400**
Hettinger	ND	25,000	27,000	23,000	23,000	26,000	**24,800**
Kidder	ND	72,000	72,000	74,000	73,000	76,000	**73,400**
McHenry	ND	72,000	82,000	78,000	83,000	86,000	**80,200**
McKenzie	ND	66,000	79,000	83,000	78,000	80,000	**77,200**
Mclean	ND	43,000	48,000	46,000	53,000	51,000	**48,200**
Mercer	ND	40,000	34,000	38,000	40,000	48,000	**40,000**
Morton	ND	104,000	127,000	109,000	129,000	134,000	**120,600**
Mountrail	ND	36,000	34,000	42,000	42,000	47,000	**40,200**
Oliver	ND	39,000	34,000	46,000	38,000	37,000	**38,800**
Renville	ND	8,000	9,000	8,000	7,000	7,000	**7,800**
Sheridan	ND	23,000	30,000	23,000	24,000	21,000	**24,200**
Sioux	ND	37,000	31,000	34,000	38,000	36,000	**35,200**
Slope	ND	31,000	33,000	33,000	29,000	33,000	**31,800**
Stark	ND	64,000	65,000	61,000	60,000	63,000	**62,600**
Ward	ND	42,000	41,000	47,000	53,000	47,000	**46,000**
Wells	ND	26,000	29,000	24,000	27,000	26,000	**26,400**
Williams	ND	31,000	39,000	42,000	38,000	38,000	**37,600**
Corson	SD			74,000	76,000	77,000	**75,667**
Harding	SD			72,000	73,000	76,000	**73,667**
Perkins	SD			102,000	105,000	103,000	**103,333**
Total							**1,615,247**

Source: http://www.usda.gov/nass; 1998 - 2002, all cattle inventory

As can be seen in the above tables, the number of cattle near each plant is very significant. The percentage of the cattle that would be required to use the DDGS produced by each plant is a small fraction of the total cattle in each local DDGS market. The local markets for DDGS are summarized in Table 40.

Table 40 – Local DDGS Markets and Cattle Data

Site	Ethanol Plant Size (MMGPY)	DDGS Produced (tons/year)	Local DDGS Market Radius (miles)	All Cattle within Local DDGS Market	% of Cattle Needed for DDGS Output
Site #1	40	129,000	100	1,677,607	8%
Site #2	30	96,000	75	855,480	11%
Site #3	10	32,000	30	204,200	16%
Site #4	40	129,000	100	1,615,247	8%
Site #5	40	129,000	100	1,615,247	8%

Source for cattle data: http://www.usda.gov/nass; 1998 - 2002, all cattle inventory

The large number of cattle in counties within the local DDGS markets also represents an excellent opportunity to sell the plant's distillers grains in the wet form (about 65% moisture) rather than dry (10% moisture). The real opportunity for the ethanol plant is to avoid the energy cost to dry the distillers grain. Up to one-third of the energy use of an ethanol plant goes to drying the distillers grain. Selling wet distillers grains can result in a significant energy saving for the ethanol plant.

The influx of more DDGS from additional ethanol plants should not impact traditional local feed products such as sugar beet wastes or potato wastes because the DDGS from local ethanol plants would be marketed as a corn replacement, to make up for the diversion of corn from animal feed uses to ethanol production. In addition, the primary interest in DDGS as a feedstuff for livestock is its relatively high protein content, which will not impact low-protein materials like sugar beet and potato processing wastes, which are high in carbohydrates.

Regional Markets for DDGS

The regional market is one that is outside of the immediate local market, yet is within the state as well as neighboring states. This market will likely be serviced by road and rail, and is within a 450-mile radius of the plant. For the sites in North Dakota, this includes the states of North and South Dakota, Minnesota, Nebraska, Iowa, Montana, Wyoming, and Colorado in the US, and parts of the provinces of Alberta, Saskatchewan and Manitoba in Canada. Cattle production in the regional markets is shown in Table 41.

The market opportunities are very large with over 35 million head of cattle in the combined states and provinces in the region. The distillers grain would have to be dried, however, to ship to the regional market.

Distillers Grain Pricing

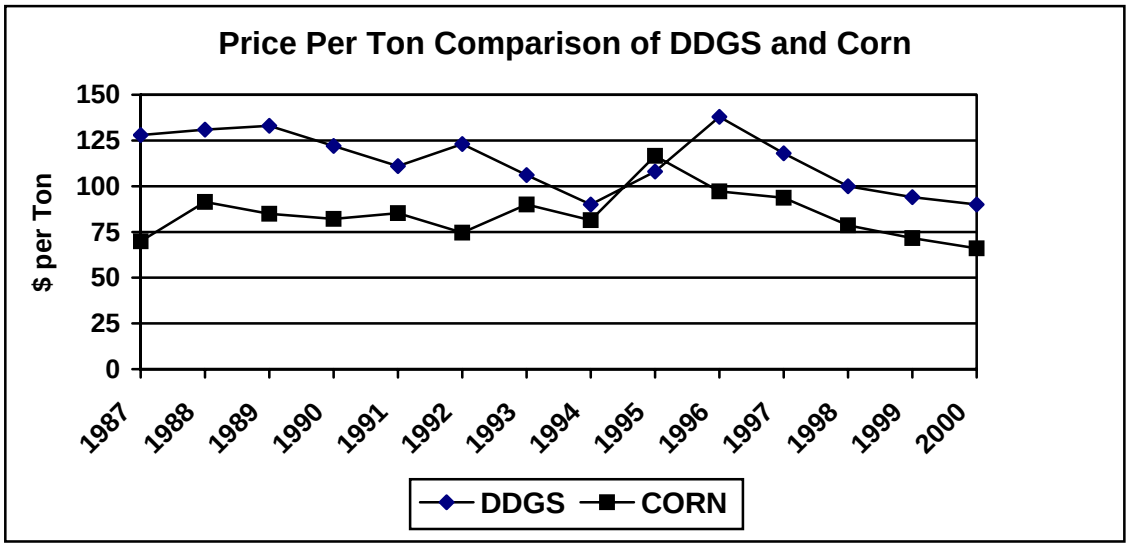
Historically, the distillers grain market has been very steady in comparison to the ethanol market (see Figure 14).

Table 41 – Regional Cattle Production
(USDA, 2002; Statistics Canada, 2001)

State	Year	Cattle All head	Beef Cows head	Milk Cows head
ND	2002	1,970,000	1,008,000	42,000
SD	2002	3,950,000	1,792,000	98,000
MN	2002	2,550,000	410,000	500,000
NE	2002	6,400,000	1,932,000	68,000
IA	2002	3,550,000	985,000	205,000
WY	2002	1,470,000	815,000	5,000
MT	2002	2,450,000	1,451,000	19,000
CO	2002	3,050,000	799,000	NA
8-State Total	2002	**25,390,000**	**9,192,000**	**937,000**
Manitoba	2001	1,424,427		
Saskatchewan	2001	2,899,502		
Alberta	2001	6,615,201		
3-Province Total	2001	**10,939,130**	**NA**	**NA**

DDGS market price is determined through a number of factors that include the market value of corn, the market value of soybean meal and other competitive protein ingredients, the performance or value of DDGS in a particular feed formulation and the supply and demand within the market.

Figure 14 – Historical Pricing of DDGS and Corn, Illinois Markets



(Source: BBI International)

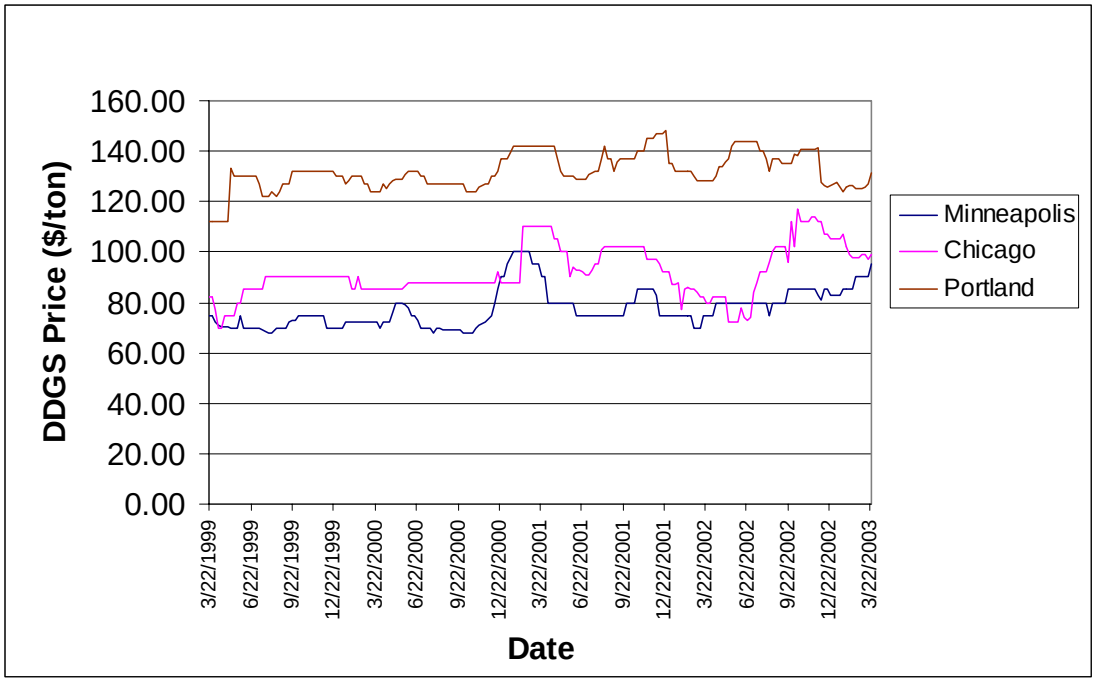
While the corn and DDGS prices do not track exactly, they generally tend to follow each other. The domestic and international soy meal markets, dairy, poultry and cattle markets, and seasonal changes due to summer pasturing, all impact DDGS prices. The rule of

thumb is that roughly 75% of an increase in the price of corn can be offset by an increase in the selling price of DDGS. While this generally holds true, it is not always the case and the above mentioned market issues often impact the price of DDGS to a greater degree than the price of corn.

The current price for DDGS in the North Dakota region is on the order of $95 per ton plus an additional $10 to $15 per ton for local delivery to the feeding operation. Historical DDGS pricing for select national markets as reported by *Feedstuffs Magazine* is shown in Figure 15. Historical corn and DDGS pricing for product delivered to Minneapolis as reported by *Feedstuffs Magazine* is shown in Figure 16. Analyzing this data reveals that $2.10 per bushel corn corresponds to about $95 per ton DDGS in North Dakota. Adding $5 per ton for transportation to local markets results in a price of $100 per ton. The equivalent price for wet distillers grain with 65% moisture is $38.88.

The data in Figure 15 show the relationship between DDGS prices and point of origin. Prices for DDGS are least in the Minneapolis market, reflecting the low cost of corn to the state's many ethanol plants. As the DDGS is shipped to more distant markets, the price of DDGS increases to reflect the additional transportation costs, and the higher cost of corn which sets the standard for the DDGS market. This is reflected in the higher price for DDGS in Chicago, and the highest price per ton for Portland.

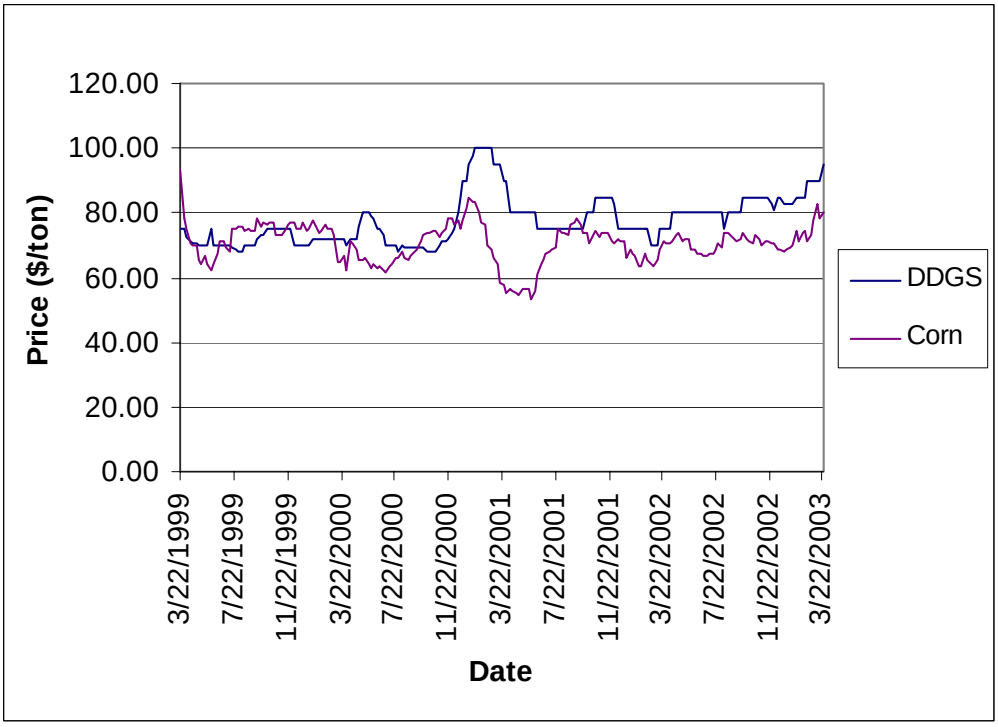
Figure 15 – Historical DDGS Pricing for Select National Markets



(Source: Feedstuffs Magazine)

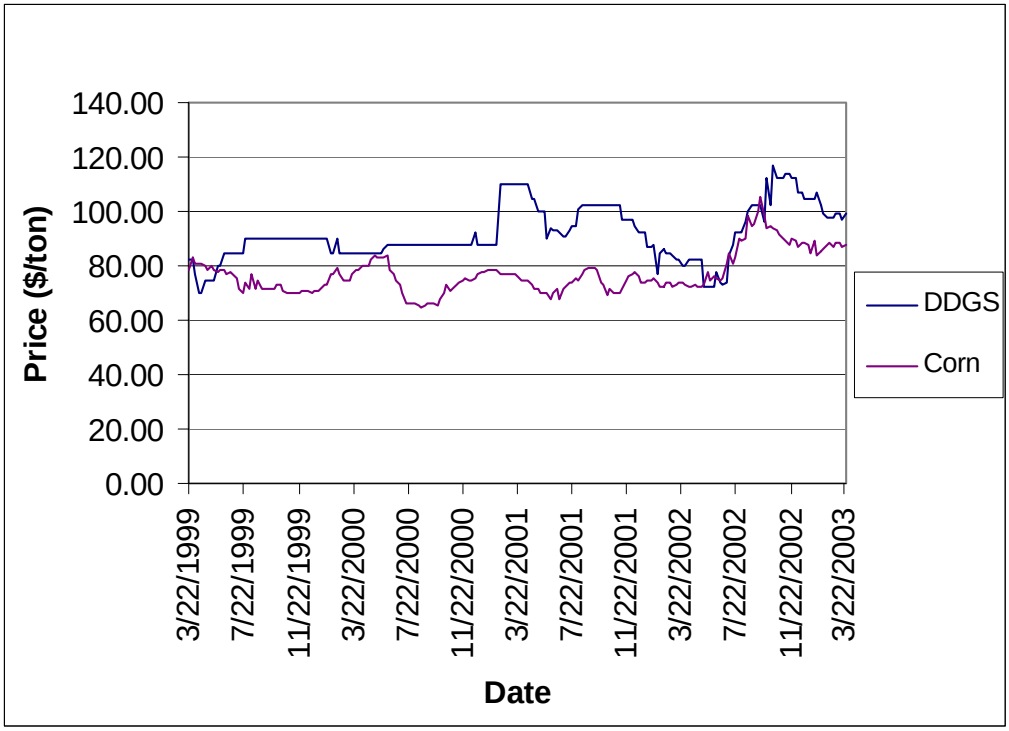
The relationship between the price of corn and the price of DDGS is further demonstrated by data shown in Figure 16, Figure 17 and ***(Source: Feedstuffs Magazine)*** Figure 18.

Figure 16 – Historical Price of DDGS and Corn in the Minneapolis Market



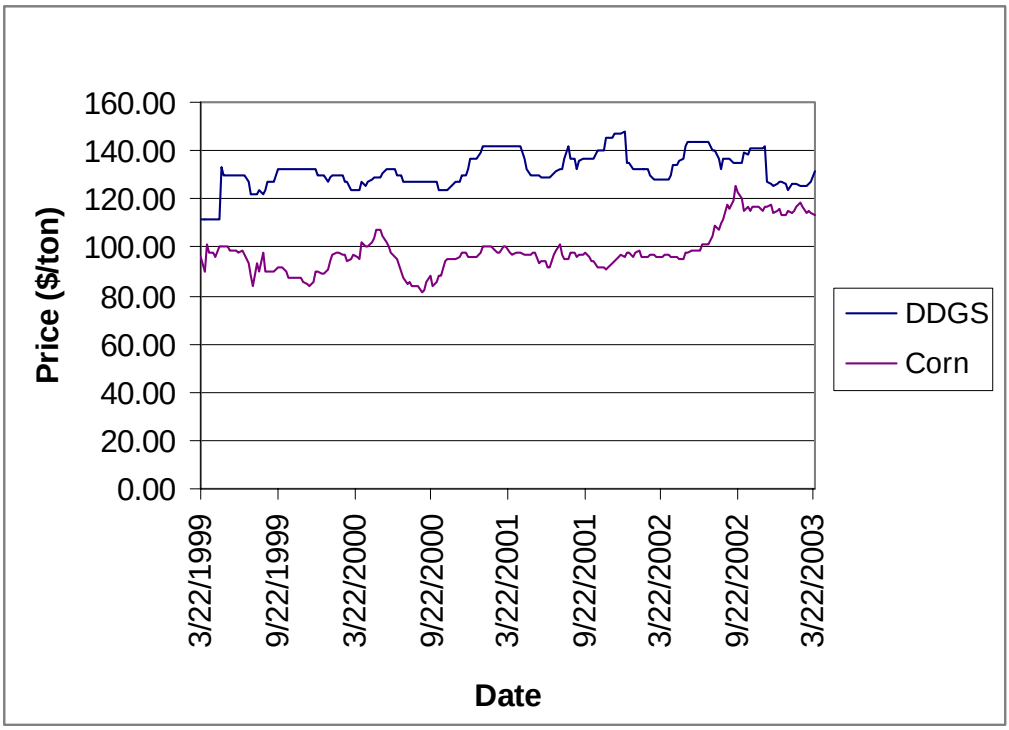
(Source: Feedstuffs Magazine)

Figure 17 – Historical Price of DDGS and Corn in the Chicago Market



(Source: Feedstuffs Magazine)

Figure 18 – Historical Price of DDGS and Corn in the Portland Market



(Source: Feedstuffs Magazine)

These figures demonstrate that as the price of corn goes up, the price of DDGS goes up accordingly. The data also show that the difference in price between corn and DDGS on a

tonnage basis increases with increasing cost of corn: the average difference between the price of DDGS and corn in Minneapolis on a tonnage basis is $7.02, for Chicago the figure is $14.74, and in Portland, DDGS averages $33.50 more per ton than corn. These data indicate that a plant or plants in North Dakota should seek to maximize the selling price obtained for DDGS while minimizing the costs associated with transportation to the customer.

Distillers Wet Grain

Distillers Wet Grain (DWG) is the wet cake that comes directly from the centrifuge. It has approximately 65% moisture. The syrup that is centrifuged out is evaporated and returned back into the cake. This product remains at about 65% moisture after the evaporated syrup is returned to the cake. Methods of calculating the price of DWG are discussed below. The plant must insure that it maximizes the price of its byproducts and should not sell DWG for less than the equivalent price at which it can sell DDGS. There are several methods for calculating Distillers Wet Grain price.

Method 1: A plant in Winnebago, Minnesota, uses the following method. Every Monday, the plant manager reviews his natural gas price and determines his cost to dry the DWG. That cost is subtracted from the price the product can be sold for as DDGS and that determines the selling price of DWG.

Example:	DDGS Selling Price FOB Plant	$90.00
	Cost to Dry	$22.00
	DWG	$68.00
	DWG Selling Price	$23.80*

*Sold on a dry matter basis ($68.00 X 35% dry matter = $23.80)
Source: Discussions with Steve Markham, Commodity Specialists Company

Method 2: Several of the plants in Nebraska use the following method.

% Dry Matter DWG / % Dry Matter Corn x (90% x corn $/lb) x 2000

Example:
DWG 35% dry matter
Corn 85% dry matter
Corn $2.35/bu or $4.20/cwt
90% $4.20 cwt = $3.78 cwt ($0.0378 per pound)

35% / 85% = .4117 x $.0378 x 2000 = $31.13 per ton
Source: Discussions with Ken Knight, Knight Feedlots

It should be noted that these two methods of calculating DWG are entirely different. The first calculates the cost of DWG based on subtracting the cost of drying which is essentially the cost of natural gas to dry plus some additional electricity and maintenance

from the market price of DDGS FOB the plant. The second method is based on the cost of corn, which relates to the nutritional value of the DWG. These methods of DWG pricing are common in the Midwest. Competing sources of protein and the performance of DWG in local dairies will also impact the value of the DWG. DWG quality and consistency are also very important variables that can impact the DWG price. The ethanol plant must insure that it maximizes the revenue from its DWG byproduct regardless if it is sold wet or dry.

To the evaluate impact of selling DWG, we assume the total DDG revenue remains constant and the savings is the reduction in natural gas used by the DDG dryers. These calculations are presented in the financial analysis section of this report. The plant must insure that it maximizes the price of its byproducts and should not sell DWG for less than the equivalent price at which it can sell DDGS.

CO_2 Markets

Dry ice and liquid carbon dioxide are principally used as expendable refrigerants in the food industry. Carbon dioxide, whether solid, liquid, or gaseous, is recognized as safe for use in foods. Food applications include:

- Beef, pork, and poultry slaughter operations
- Frozen food storage and transportation
- Supplemental cooling for refrigerated products
- Meat, sausage and bakery processing
- Airline catering
- Gift food packaging
- Carbonation of beverages

Non-food applications include:

- Various chemical processes
- Oil extraction via CO_2 injection
- Dermatologists
- Blood banks
- Pharmaceutical manufacturing
- Shrink fitting
- Cryogenic blasting
- pH control

Currently in the U.S. about one third of fermentation carbon dioxide (CO_2) produced from ethanol plants is captured and two thirds is vented to the atmosphere. The carbon dioxide captured is in most cases from very large ethanol plants. Capture of CO_2 from medium sized and smaller plants is usually not justified unless special market conditions are present. If justified the ethanol plant can easily capture raw carbon dioxide. However, it must be processed further if it is to be used for commercial purposes.

A CO_2 processing company would prefer to use high pressure CO_2 rather than liquid CO_2 since it reduces the capital costs for equipment and processing costs. Typically, a CO_2 processing company will construct a processing facility next to the ethanol plant. The raw CO_2 is then piped to the processing facility for finishing. In order for the processing facility to be economically viable, there must be a close market for the finished CO_2. Packing plants, soft drink bottlers, and food processors are just a few of the numerous users of fermentation CO_2.

For the North Dakota sites, there is already significant existing CO_2 production capacity in the immediate vicinity at the Dakota Gasification Corporation in Beulah, ND. A contact familiar with the operation in Beulah said the CO_2 contribution of the ethanol plant would be relatively insignificant when compared to the existing output of the synfuels plant. In addition, there are quality, pressure and purity issues that further reduce the utility of the ethanol-derived CO_2 for enhanced oil recovery (EOR).

According to contacts at Praxair, BOC and Airgas, the three major CO_2 suppliers in the US, there would be virtually no interest in marketing the CO_2 co-product from an ethanol plant in North Dakota. There are at least two reasons why there is little interest in capturing the CO_2 from the plant:

- the local market is actually quite small and there is no demand for additional supplies, and
- the lack of an adequate local market makes the costs of capturing the CO_2 prohibitive.

In addition, our contact at Praxair in Bismarck indicates that the existing ethanol plants in South Dakota are essentially “giving” the CO_2 away for the cost of transportation alone. Similarly, contacts at Airgas indicate that most of the regional plants have foregone the cost of equipment to capture the CO_2 and are simply venting the gas. When asked for a current market value for CO_2, the response was “there is no demand so the value is zero.”

Based on this information, revenue from CO_2 is not included in the economic analysis for the proposed sites.

Conclusion for Co-Products

Given the large number of cattle in the immediate vicinity (up to 100-miles) of the proposed sites, there is a good possibility that the plants could sell the bulk of the DDGS production into local markets. In addition, due to the number of feedlots in the area, it is likely that the plant could sell a significant portion of its distillers grain wet. It normally takes some time to develop the local market for wet distillers grain following plant startup.

The economics and project proforma have been based on selling all of the distillers grain dry as DDGS, however, as this is a realistic and conservative assumption. The plant design and economics therefore include a DDGS drying system. Although the potential

local market is substantial, regional markets for DDGS are significant and should be developed with the aid of a DDGS marketing company. A market price of 105% of the dry weight corn price will be used for DDGS in the financial analysis.

Another consideration for a plant or plants in North Dakota is the premium priced commanded by DDGS in Pacific Northwest markets. A plant in North Dakota should work with a DDGS marketing firm to balance the benefit of selling DDGS or DWG locally versus the higher prices that could potentially be tapped by selling DDGS into the Pacific Northwest.

Because there is currently an over supply of CO_2 production capacity in the region, revenue from CO_2 sales are not included in the financial forecast. It is unlikely that an ethanol plant in North Dakota would find adequate local markets to justify the capital cost associated with CO_2 capture and purification.

VII. OVERVIEW OF ETHANOL TECHNOLOGIES

The production of ethanol or ethyl alcohol from starch or sugar-based feedstocks has been practiced for thousands of years. While the basic process steps remain the same, the process has been considerably refined in recent years, leading to a highly efficient process that now yields more energy in the ethanol and coproducts than is required to make the products.

In the dry milling process, corn or other high-starch grains are first ground into meal and then slurried with water to form a mash. Enzymes are added to the mash to convert the starch to the simple sugar, dextrose. Ammonia is also added for pH control and as a nutrient to the yeast. The mash is processed through a high temperature cook step, which reduces bacteria levels prior to fermentation. The mash is cooled and transferred to the fermenters where yeast is added and the conversion of sugar to ethanol and carbon dioxide (CO_2) begins.

After fermentation, the resulting "beer" is transferred to distillation where the ethanol is separated from the residual "stillage". The ethanol is concentrated to 190 proof using conventional distillation and then is dehydrated to approximately 200 proof in a molecular sieve system. The resulting anhydrous ethanol is blended with about 5% denaturant (usually gasoline) and is then ready for shipment to markets throughout the country.

The stillage is separated into a coarse grain fraction and a "soluble" fraction by centrifugation. The soluble fraction is concentrated to about 30% solids by evaporation. This intermediate is called Condensed Distillers Solubles (CDS) or "syrup." The coarse grain and syrup fractions are then mixed and dried to produce distillers dried grain and solubles (DDGS), a high protein animal feed product.

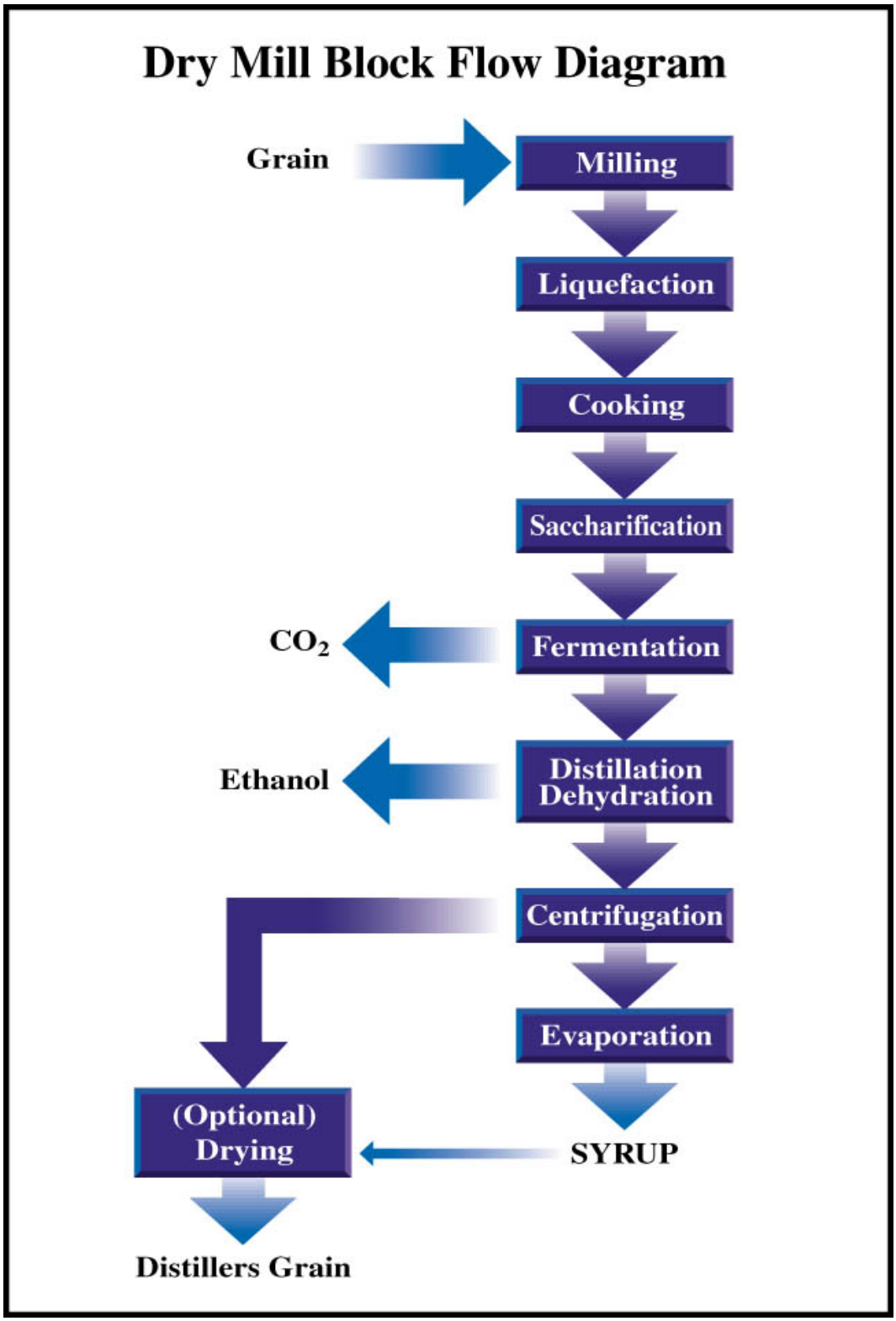
A simplified block diagram of a typical dry milling ethanol plant is shown in Figure 19.

Technology Supply and Construction Services

The project sponsor should ensure that a reputable design and construction firm or team of firms is engaged during the development of the project.

The construction firm should guarantee the completion of the project within a fixed budget and time schedule and should warrant all workmanship for a period of not less than a year following startup. The firm should be capable of posting performance and materials and labor bonds and should be willing and financially able to accept liquidated damages provisions in their contract if required by the sources of debt financing for the project.

Figure 19 – Generic Corn to Ethanol Process Schematic



The supplier of the ethanol process technology and designer of the process should be experienced and well regarded, as it will be required to guarantee the performance of the plant so long as the construction firm builds it to the designer's specifications. This guarantee should include minimum yield and quality of products from a given quality and quantity of feedstock (usually a bushel of #2 yellow corn), energy and utility consumption, use of chemicals and enzymes, process water consumption and the volume and characteristics of wastewater; all on a per bushel basis. The guarantee normally is considered satisfied if a successful performance test of several days duration (one that proves the process performance criteria) is completed after plant startup.

The designer and constructor are sometimes the same firm. Sometimes the constructor will provide the performance guarantees of the designer that acts as a subcontractor. Sometimes the contracts with designer and constructor are separate documents. BBI recommends that there be a single "turnkey" contract providing the strongest possible financial resources to back the design and construction scope of work.

BBI, as matter of policy, does not provide specific recommendations for design and construction services. In addition, while all of the vendors listed below are capable of providing process guarantees, the specific guarantee is something to be negotiated during the project development phase of the project. What follows is a list and short description of firms that we know to be successful and reliable in the ethanol industry:

Broin & Associates, Inc. (Sioux Falls, SD)

Broin has executed several ethanol projects as a technology supplier and oftentimes as a turnkey contractor providing all required services in Minnesota, Missouri and South Dakota, with the plants ranging in size from five to 40 million gallons of annual ethanol production. All are corn-fed. Our understanding is that all business conducted by Broin today is as a turnkey contractor.

Fagen, Inc. (Granite Falls, MN)

Fagen Inc. has been the design-build contractor, E.P.C. contractor, general contractor, or subcontractor for at least 48 ethanol plant projects, both new construction and expansion jobs, and claims more ethanol industry experience than any other U.S. firm during the past decade. With the addition of Fagen Engineering LLC and Fagen Management LLC, Fagen now performs the civil, structural, mechanical, and electrical engineering aspects for ethanol projects and provides management services after construction and startup. They typically utilize the ethanol process design of ICM, Inc.

Fagen, Inc. is located at 501 West Highway 212, Granite Falls, MN 56241
Telephone (320) 564-3324. Web address: http://www.fageninc.com/

Delta T Corporation (Williamsburg, VA)

Headquartered in Williamsburg, VA, Delta-T is a design-build firm that provides alcohol plants, systems and services to the fuel, beverage, industrial and pharmaceutical markets. Delta-T is known for pioneering many of the innovations currently in use by the newest generation of ethanol plants, including the commercialization of molecular sieve dehydration, zero discharge of process wastewater, and more efficient refining and purification systems to produce high quality alcohols. Delta-T has provided alcohol production, dehydration and purification solutions to more than 60 clients worldwide, including projects in Russia, India, Western and Eastern Europe, Africa, the Caribbean and South America.

Delta-T Corporation is located at 323 Alexander Lee Parkway, Williamsburg, VA 23185
Telephone (757) 220-2955. Web address: http://www.deltatcorp.com/.

ICM, Inc. (Colwich, KS)

ICM, Inc. of Colwich, KS, serves the agricultural industry by developing and implementing innovative and practical processing solutions. ICM, Inc. employs about 100 people in all aspects of ethanol project development and operation including cash and commodity trading of corn, marketing of ethanol and distillers grain, process consulting, engineering, equipment fabrication, field installation, and plant start-up. The former technology leader of High Plains Corporation formed ICM. High Plains operates plants in Nebraska, Kansas, and New Mexico. ICM does own and operate a facility in Russell, Kansas, which acts as both a training and research facility for their technology. Six of the latest ethanol plants in the United States have utilized ICM technology.

ICM Inc. is located at 310 N. First Street, Colwich, KS 67030
Telephone (316) 796-0900. Web address: http://www.icminc.com/.

Katzen International, Inc. (Cincinnati, OH)

Katzen is one of the most experienced ethanol plant process designers and technology suppliers in the world, having operated worldwide for over forty years. Katzen International, Inc. was formed in 1955 by Dr. Raphael Katzen. Katzen International provides innovative and advanced design concepts in a wide variety of industries, such as agriculture, chemicals, sugar, cryogenic and pulp and paper. Although based in the United States, Katzen has completed projects in over 25 countries.

Katzen International Inc. is located at 2300 Wall Street, Suite K, Cincinnati, Ohio 45212
Telephone (513) 351-7500. Web address: http://www.katzen.com/

Lurgi/PSI, Inc. (Memphis, TN)

This firm was created approximately three years ago with the purchase of Process Systems, Inc. ("PSI") of Memphis by Lurgi AG of Germany. The company is part of the GEA Group, the largest food technology company in the world. PSI is best known as a process engineer and as a turnkey contractor in the corn wet milling and the sugar beet

processing industries. The company's ethanol work in the United States has been in association with its wet milling activities and in the expansion of large dry milling facilities with respect to corn as a feedstock.

Lurgi PSI Inc. is located at 1790 Kirby Parkway, Suite 300, Memphis, TN 38138
Telephone (901) 756-8250. Web address: http://www.lurgipsi.com/

Vogelbusch USA, Inc. (Houston, TX)

Vogelbusch USA, Inc. is a subsidiary of Vogelbusch GMBH, a large process engineering company, headquartered in Vienna, Austria. The worldwide company claims to have more ethanol capacity in place, utilizing its technology, than any other designer. Vogelbusch provides technologies for fermentation, separation, distillation and evaporation with a focus on contracting of tailor-made plants based on Vogelbusch proprietary technology or client technology for the sugar, starch, pharmaceutical, chemical and food industries. The U.S. operation offers its license and design services in tandem with other firms and does not undertake any construction activity.

Vogelbusch USA, Inc. is located at 10810 Old Katy Road, #107, Houston, Texas 77043
Telephone (713) 461-7374. Web Address: http://www.vogelbusch.com/

VIII. OVERVIEW OF LIGNITE COMBUSTION TECHNOLOGIES

This section presents a brief overview of the lignite industry in North Dakota and lignite combustion technologies as they relate to the proposed lignite-fired ethanol production facility evaluation.

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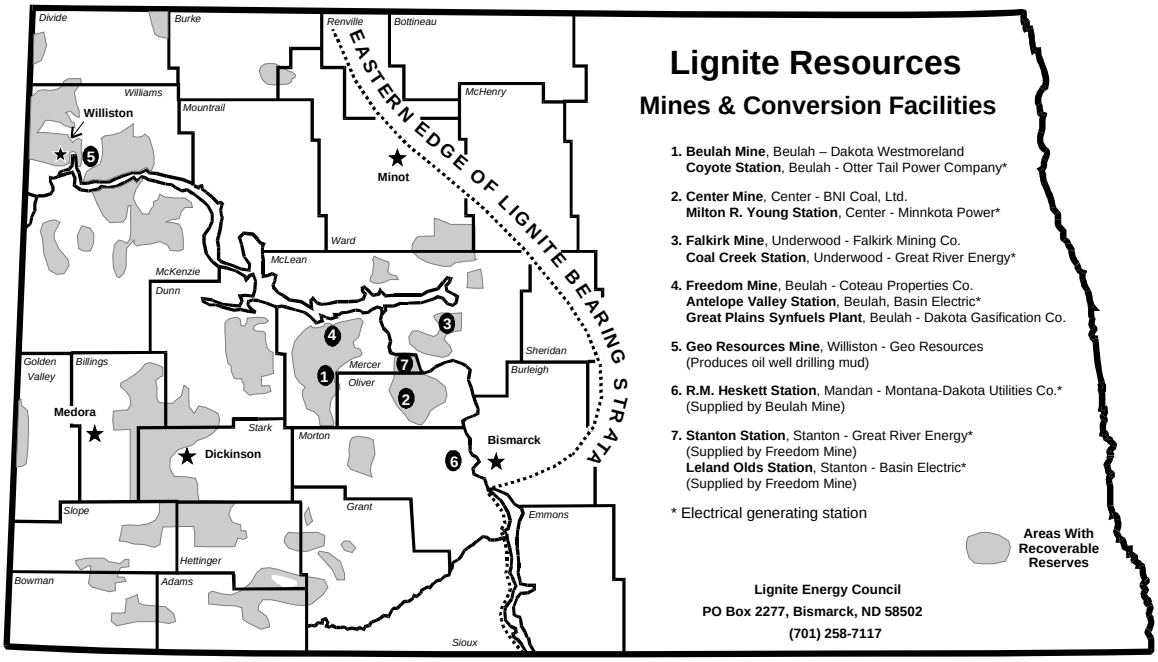
Review of North Dakota Lignite Industry

As discussed previously and shown below, the lignite industry in North Dakota centers around four lignite mines in the west-central region of the state (and one small mine in eastern Montana). These mines service seven coal-burning electrical stations in North Dakota (and one small plant in eastern Montana), and the Great Plains Synfuels Plant, as shown below. Six of the generating stations are located in close proximity to the mines (mine-mouth or within about 10 miles) while the Heskett Station in Mandan is located approximately 75 miles from its supplying mine in Beulah.

Figure 20 – Lignite Mines and Lignite-fired Power Stations in North Dakota



The tables below provide a summary of the lignite mines and power generating stations in the region.

Table 42 – Summary of Regional Lignite Mines

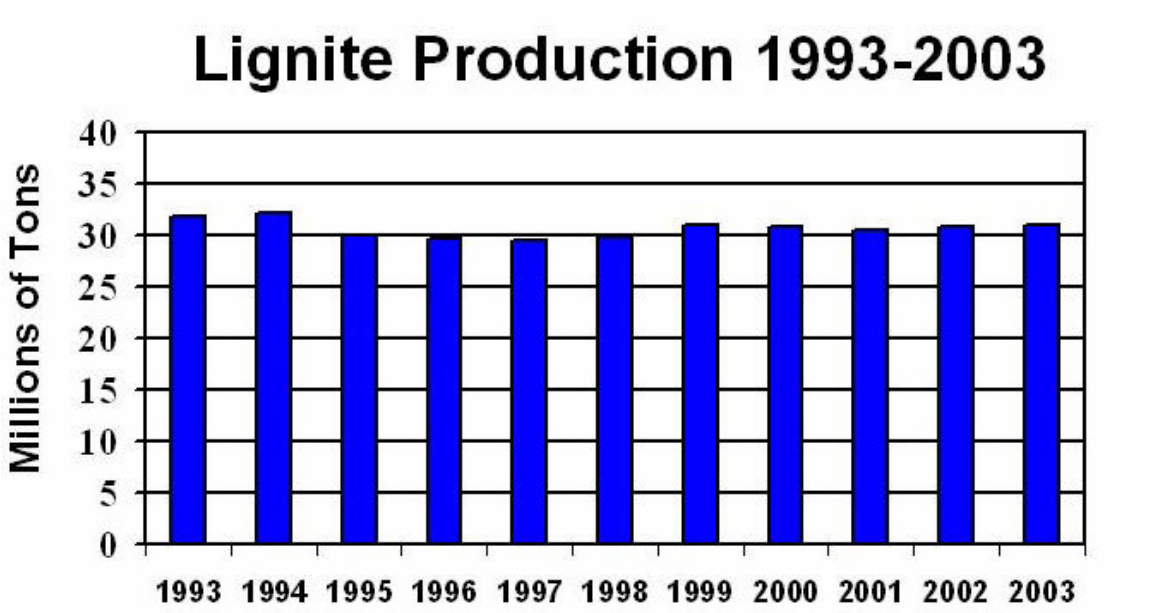
Name	Location	Owner	Mine Capacity (tpy)	Major Clients
Freedom	Beulah	North American Coal Corporation	16,000,000	Great Plains Synfuels Antelope Valley Station Leland Olds Station Stanton Station
Falkirk	Underwood	North American Coal Corporation	7,000,000	Coal Creek Station
Beulah	Beulah	Dakota Westmoreland	3,000,000	Coyote Station Heskett Station
Center	Center	Minnesota Power	4,500,000	Milton Young Station
Savage	Savage, MT	Dakota Westmoreland	250,000	Sugar Beet Processor Lewis & Clark Station
Total Capacity of Mines			**30,750,000 tpy**	

Table 43 – Summary of Regional Power Stations

Station Name	Location	Power Capacity	Date on Line
Antelope Valley	Beulah	450 MW 450 MW	1984 1986
Leland Olds	Stanton	212 MW 440 MW	1966 1975
Stanton	Stanton	202 MW	1966
Coal Creek	Underwood	550 MW 550 MW	1979 1981
Coyote	Beulah	414 MW	1981
Heskett	Mandan	25 MW (idle) 75 MW (FBC)	1954 - 1995 1963 (1987)
Milton R. Young	Center	250 MW 455 MW	1970 1977
Savage	Savage, MT	48 MW	1958
Total Regional Power Capacity		**4,096 MW (4.1 GW)**	

The lignite industry in North Dakota employs over 3,000 direct employees, generating total business activity of $1.5 billion dollars (Coon et al., NDSU, March, 2003). As reported by the North Dakota State Office of Tax Commissioner, North Dakota's taxable coal production has averaged 30 million tons of lignite annually over the last 10 years (see figure below). Approximately 80% of the lignite produced is used for power generation, and 20% for synthetic natural gas production.

Figure 21 – Historical Annual Lignite Production



(Source: The Lignite Energy council)

Lignite Availability

According to the Lignite Energy Council, North Dakota ranks 9th among U.S. coal-producing states. With an estimated 35 billion tons in recoverable reserves, the state has enough coal to last 1,000 years at today's rate of production. With over 30 million tons produced annually, lignite would be readily available for a lignite-fired ethanol production plant or plants in North Dakota.

Lignite Costs, Transportation Requirements and Infrastructure

The four principal lignite mines in North Dakota were contacted regarding the price of lignite and the infrastructure that would be required for the proposed projects. Based on the information obtained, the cost of lignite at the mine mouth is estimated to be between $10 and $12 per ton crushed to 2-inch nominal size. Transportation costs would be paid by the ethanol plant and would depend on the mode of transportation: road or rail.

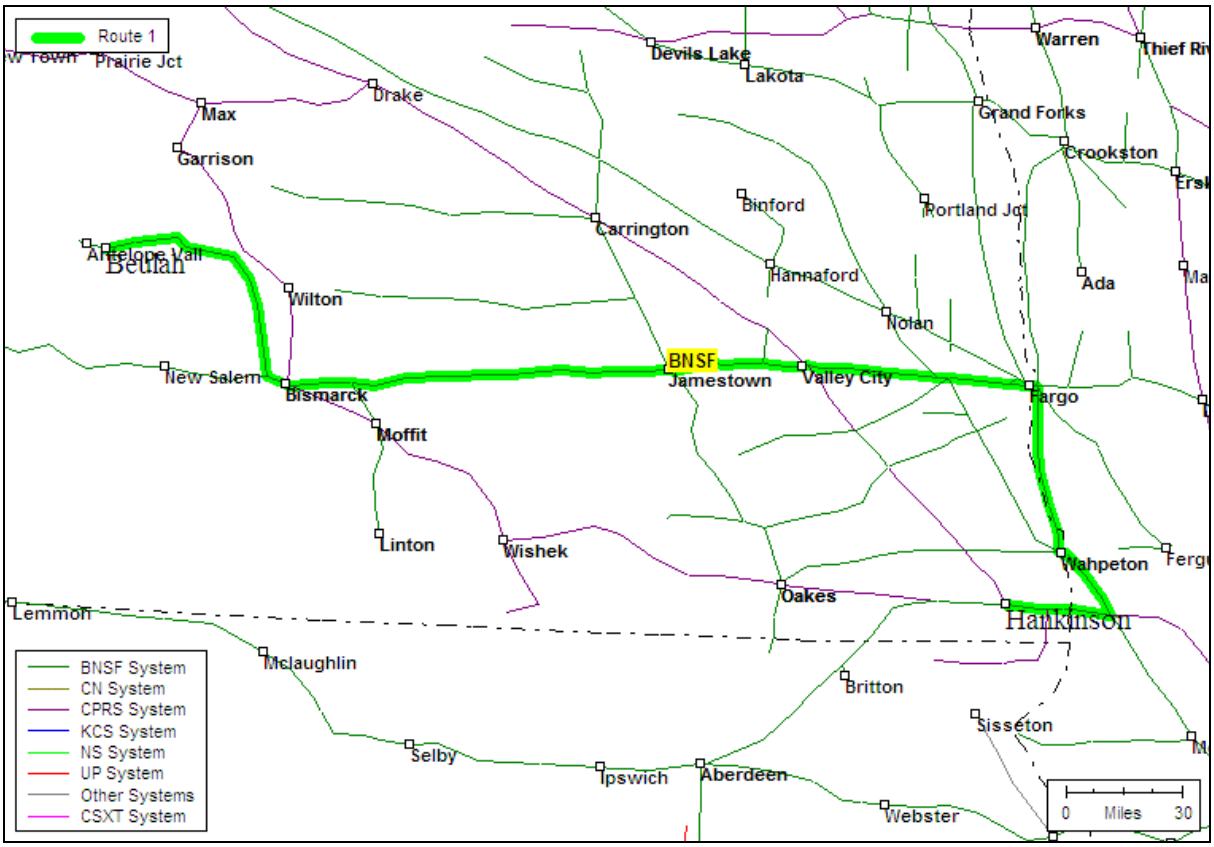
While not popular with the general public, there is nothing to prevent lignite from being delivered to the ethanol plant by truck. For the largest scale of ethanol plant under consideration, 40 MMGPY, the daily requirement of 370 tons could be met with less than 20 truckloads, or less than three trucks per hour over an 8-hour period. Truck requirements for a 10 MMGPY ethanol plant would only be five trucks per day.

Based on a round trip of 60 miles taking three total hours, at $60 per hour, including loading and unloading, the cost of transportation would be approximately $9 per ton, resulting in a delivered fuel price of approximately $20 per ton.

Because the fuel demands of an ethanol plant are very small compared to a utility-scale power plant, delivery of the lignite fuel by rail is unlikely. With approximately 100 tons per rail car, the 40 MMGPY facility would require less than four rail cars per day; the 10 MMGPY plant would need just one rail car per day to meet its entire energy needs.

Rail estimates obtained from BNSF were $8.95 per ton to Valley City and $12-14 per ton to Hankinson. The BNSF route map for sites #1 and #2 is shown below.

Figure 22 – BNSF Rail Route to Sites #1 and #2



(Source: BNSF)

Lignite would be delivered by rail to the Hankinson and Valley City sites from whichever mine source provided the cheapest feedstock. Lignite would be delivered by truck to the Minot site from the Falkirk mine; lignite from the Center mine would be delivered to the Richardton site by truck.

The infrastructure required to utilize lignite as the power source for ethanol production will necessarily depend on the specific combustion technology employed for the project. Regardless of the technology selected, the required infrastructure would include the following unit operations:

- fuel pretreatment (drying, sizing, densification);
- combustor or gasifier + ash container;
- (multi)cyclone;
- tar cracker;
- scrubber + demister;
- gas/air mixing device;
- compressor; and
- gas engine/generator set.

In addition, a lignite-fired ethanol plant would require any size reduction and classification equipment required by the particular combustion technology in use, the combustion system equipment including control system, ash or slag removal equipment, the steam boiler and feed water system, a steam turbine, and stack emission control equipment. There would also be infrastructure associated with lignite delivery and storage and ash handling and storage, as well as receiving and handling systems for bulk chemicals including limestone, ammonia and lime required to meet emissions and pollution control requirements.

Plant Energy Requirements and Co-Generation Potential

Ethanol plants have a combination of energy requirements, split between steam, hot air and electricity. Steam is required for cooking the mash, sterilizing the fermentation medium, and distilling the ethanol product and concentrating the thin stillage. Hot air is required for drying the distillers grains into the DDGS co-product. Electricity is required to run rotating equipment and operate miscellaneous equipment including lights, computers, sensors, devices, etc. The energy requirements of the proposed plant scales are summarized in the following table.

One aspect of ethanol plant energy requirements that could impact the feasibility of co-generation of electricity and steam from lignite is a “mismatch” between the plant’s steam and hot air requirements versus the plant’s electrical demand. A 40 MMGPY plant will require approximately 60 MW equivalents of total energy, but 56 MW_{eq} of this requirement (93%) is for steam and hot air. Only 4 MW_{eq} would be required for electricity. This means the project would need a very small steam turbine, much smaller than industry norms, which could have a disproportionately high capital cost.

Another potential complication for lignite-powered co-generation for ethanol production is the energy requirement of the DDGS driers. The DDGS driers are routinely fired using natural gas. For the proposed lignite-fired ethanol plant, some changes to the standard ethanol production process would be required depending on the specific combustion technology in use.

Table 44 – Ethanol Plant Co-generation Energy Requirements

Plant Size (denatured gal)	Total Heat Demand (btu/gal anhydr. EtOH)	Heat Demand (MCF/hr)	Annual Heat Energy Demand (MCF/yr)	Total Heat Energy Annual MW equivalent
10,000,000	42,778	49	407,407	14.2
30,000,000	42,778	146	1,222,222	42.6
40,000,000	42,778	194	1,630,000	56.9
	Heat demand is combined drying and steam requirements			
Plant Size (denatured gal)	**Drying (MCF/hr)**	**Drying MW equivalent**	**Steam (pph)**	**Steam MW equivalent**
10,000,000	16	4.69	32,496	9.52
30,000,000	48	14.07	97,487	28.57
40,000,000	64	18.77	130,012	38.10
Plant Size (denatured gal)	**Elec. Demand (kwh/gal)**	**Annual Elec Use (kWh)**	**Annual Elec Demand (MW)**	**Total Heat and Elec Equiv. MW demand**
10,000,000	0.8	7,636,502	0.91	15.12
30,000,000	0.8	22,909,507	2.73	45.37
40,000,000	0.8	30,546,010	3.64	60.51
Plant Size (denatured gal)	**Lignite Heating Value (btu/lb)**	**Lignite Use (tons/hr)**	**Lignite Use (tons/day)**	**Lignite Use (tons/yr)**
10,000,000	6,750	3.82	92	32,108
30,000,000	6,750	11.47	275	96,325
40,000,000	6,750	15.29	367	128,461

If the co-generation plant is based on conventional combustion, the plant would need to install some alternate form of drying system in lieu of the natural gas-fired system. This might be an indirect, steam-tube drier (which has been proven to be less than optimal), or an air-to-air heat recovery system to capture heat from the combustion exhaust and generate the hot air that would normally come from burning natural gas. In either case, the volatile organic compounds (VOCs) coming off the DDGS drying operation would be routed back to the combustion process as makeup air eliminating the need for a thermal oxidizer.

If the co-generation plant were based on one of the existing or emerging gasification technologies, the DDGS driers could be fired using part (20-30%) of the low Btu syngas generated by the gasifier. For such a system, lignite would be gasified into a low or medium Btu fuel gas, most of which would then be burned to generate steam. The balance of the syngas would be used to fire a conventional direct hot-air DDGS drier. The exhaust from the DDGS driers would be routed back to the process as makeup air, eliminating the need for the thermal oxidizer.

In either case, a small steam turbine would be used to provide the plant's electrical needs.

Overview of Combustion Technologies

The co-generation technologies that are available and can use lignite as a fuel source fall into two major categories: combustion and gasification. Combustion and gasification are related processes that differ primarily in the amount of air allowed into the reaction chamber.

Combustion Processes

Combustion processes require air (oxygen) to combust the fuel source. Air containing oxygen is metered into the combustion chamber along with the fuel source on a stoichiometric basis to achieve "oxidation" of the fuel, i.e. combustion. The completeness of the oxidation process affects the amount of air emissions and dictates the type of pollution control equipment required to meet regulated limits. Combustion systems come in a variety of configurations, depending on the type of fuel, the energy and moisture content of the fuel, the temperature inside the combustion chamber and the optimum particle size. Based on these considerations, the available systems have different material handling systems on the front-end, different boiler components, different ash or slag recovery components (fixed or moving grates), and different pollution and particulate control equipment options.

According to C. B. Oland in a report prepared for Oak Ridge National Laboratory in April 2002, boilers can be classified by their heat sources. For example, boilers are often referred to as oil-fired, gas-fired, coal-fired, or solid fuel-fired boilers. Coal-fired boilers can be further divided based on the equipment used to fire the boiler. The three major coal-fired boiler subclasses are pulverized-coal (PC) fired, stoker-fired, and fluidized-bed combustion (FBC) boilers.

Stoker-fired boilers include a mechanical system that is designed to feed solid fuel into the boiler. These stokers are designed to support the combustion process and to remove the ash as it accumulates. All stokers operate similarly. They use both undergrate and overfire air to burn fuel located on a grate.

The PC-fired boilers are generally large field-erected units. During operation, finely ground coal is mixed with primary combustion air and fed to the burner or burners where it ignites. Secondary combustion air is then supplied to complete the combustion process. Depending on the location of the burners and the direction of coal injection, PC-fired boilers can be classified as single- or opposed-wall, tangential (corner), or cyclone boilers. Depending on whether the ash is removed in a solid or molten state, PC-fired boilers are also classified as dry or wet bottom. Opposed-wall boilers are usually much larger than 250 million Btu per hour heat input capacity. They are used primarily for utility but may be suitable for certain industrial applications. Coal burned in cyclone boilers is crushed rather than pulverized.

The FBC boilers are capable of burning a wide range of solid fuels. In this method of combustion, fuel is burned in a bed of hot incombustible particles suspended by an

upward flow of fluidizing gas such as air. Fuels that contain a high concentration of ash, sulfur, and nitrogen can be burned efficiently while meeting stringent emission limitations. When sulfur capture is not required, inert materials such as alumina may be added to supplement the fuel ash and maintain the bed. In applications where sulfur capture is required, limestone is incorporated into the bed and used as the sorbent. The FBC boilers are categorized as either atmospheric or pressurized units. Atmospheric FBC boilers are further divided into bubbling-bed and circulating-bed units; the fundamental difference between these two is the fluidization velocity. Coal is often burned in FBC boilers, but it is also possible to burn biomass and other solid fuels. Natural gas or fuel oil is used primarily as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required.

Combustion technologies are also classified by their power production technology which can be subcritical or supercritical, referring to the pressure and temperature of the steam used to generate power. Subcritical low pressure combustion boilers operate in the 100-200 MW range; subcritical high pressure systems are common in the 300-600 MW range. Larger units can be built for either subcritical or supercritical operation (500-600 MW).
Vendors of combustion technologies appropriate for lignite that were contacted for price information include Energy Products of Idaho (EPI), Foster-Wheeler, Babcock and Wilcox, Detroit Stoker, Wellons and Von Roll Inc.

Gasification Processes

The gasification process is very similar to the combustion process except that these technologies are based on incomplete oxidation. In gasification processes, fuel is metered into the reaction or gasification chamber under oxygen-starved conditions.

What follows is based on an excerpt of a recent article written by H.E.M. Stassen and H.A.M. Knoef with Biomass Technology Group BV in the Netherlands:

Gasification is a process in which solid fuels are broken down by the use of heat in an oxygen-starved environment, to produce a combustible gas. Solids fuels that can be gasified include coal, wood, charcoal, rice husks, coconut shells and a variety of other dry biomass materials. A gasification system consists primarily of a reactor into which fuel is fed along with a limited (less than stoichiometric or that required for complete combustion) supply of air. Heat for gasification is generated through partial combustion of the feed material. The resulting chemical breakdown of the fuel and internal reactions result in a combustible gas usually called "producer gas." The heating value of this gas varies between 75 and 300 Btu per standard cubic foot (scf).

Small-scale gasifiers are all of the "fixed-bed" bed type. The different fixed-bed reactor types are often characterized by the direction of the gas flow through the reactor (upward, downward or horizontal) or by the direction of respectively the solid flow and the gas stream (co-current, counter-current or cross-current). Looking to the applications, a further distinction can be made between power gasifiers and heat gasifiers. Power gasifiers require a more or less tar- and dust-free gas while heat gasifiers are not very

sensitive to these types of impurities. Fluidized bed gasifiers are further divided into bubbling-bed and circulating-bed units; as with combustion processes, the fundamental difference between these configurations is the fluidization velocity.

The simplest type of gasifier is the fixed bed counter current gasifier or up-draft gasifier. The fuel is fed into the top of the reactor and moves downwards as a result of the conversion of the fuel and the removal of ashes. The air intake is at the bottom and the gas leaves at the top. The solid fuel moves in counter current to the gas flow, and passes through the drying zone, the distillation zone, reduction zone and the oxidation zone.

The major advantages of this type of gasifier are its simplicity, high charcoal burn-out and internal heat exchange leading to low gas exit temperatures and high gasification efficiency. In this way fuels with a high moisture content (up to 50 % wet basis) can be used. Major drawbacks are the high amounts of tar and pyrolysis products, because the pyrolysis gas does not move through the oxidation zone. This is of minor importance if the gas is used for direct heat applications, in which the tars are simply burnt. In case the gas is used for engines, gas cleaning is required, resulting in problems of tar-containing condensates.

In a conventional downdraft co-current gasifier, the fuel source is fed at the top of the reactor and air intake is at the top or from the sides. The gas leaves at the bottom of the reactor, so the fuel and the gas move in the same direction. The pyrolysis gases move through the oxidation zone (with high temperatures) and are more or less burnt or cracked. Therefore the producer gas has a low tar content and is suitable for engine applications. In practice however, a tar-free gas is seldom if ever achieved over the whole operating range of the equipment. Because of the lower level of organic components in the condensate, downdraft gasifiers suffer less from environmental objections than updraft gasifiers.

Drawbacks of the downdraft gasifier are:

- the high amounts of ash and dust particles in the gas;
- the inability to operate on a number of unprocessed fuels, often pelletisation or briquetting of the biomass is necessary;
- the outlet gas has a high temperature leading to a lower gasification efficiency;
- the moisture content of the biomass must be less than 25 %.

These gasifiers are normally small and are used in a power range from 80 to 500 kW.

A more recent development is the 'open core' gasifier design for gasification of small sized fuels with high ash content. The producer gas is not tar-free; it contains approximately 0.05 kg tar per kg gas. In the open core gasifier the air is sucked over the whole cross section from the top of the bed. This facilitates better oxygen distribution since the oxygen will be consumed over the whole cross section, so that the solid bed temperature will not reach the local extremes (hot spots) observed in the oxidation zone of conventional gasifiers due to poor heat transfer. More over, the air nozzles in

conventional gasifiers generate caves and create obstacles that may obstruct solid flow specially for solids with low bulk densities.

On the other hand, the entry of air through the top of the bed creates a downward flow of the pyrolysis gases, and transports the tars products to the combustion zone. Thus, flow problems due to the buildup of solid fuel caused by back mixing of tar are avoided.

Crossdraft gasifiers are adapted for the use of charcoal. Charcoal gasification results in very high temperatures (> 1500 ºC) in the oxidation zone which can lead to material problems. Advantages of the system lie in the very small scale at which it can be operated. In developing countries installations for shaft power under 10 kW are used. A drawback is the minimal tar cracking performance, resulting in the need for high quality charcoal.

Vendors of gasification technologies appropriate for lignite that were contacted for price information regarding the present study are listed below:

- Primenergy
- ChevronTexaco
- ConocoPhillips (Destec)
- Shell-Uhde
- BGL-Lurgi/Allied Resources
- Recovered Energy
- Westinghouse Plasma
- Chiptec
- Community Power Corporation
- Thermogenics
- Down Stream Systems/Omnifuels
- Brightstar
- RCL/US Plasma
- FERCO
- Global Energy

BBI, as matter of policy, does not provide specific recommendations for design and construction services. In addition, while all of the vendors listed above are capable of providing process guarantees, the specifics of the guarantee(s) is something to be negotiated during the project development phase of the project.

Advanced Power Generation Technologies

Two processes that are emerging for “Advanced Power Generation” are Pressurized Fluidized Bed Combustion (PFBC) and Integrated Coal Gasification Combined Cycle (IGCC). PFBC is an extension of the fluidized bed combustion (FBC) process where the reaction occurs under pressure, leading to a combined cycle with improved efficiency. The technology is still emerging and remains to be demonstrated at scales above 100 MW. IGCC is an advanced power technology that incorporates power production using

both gas and steam turbines (combined cycle). This technology has been demonstrated at scales up to 400 MW.

Preliminary Cost Estimates for Lignite Co-Generation Systems

As indicated previously, vendors of combustion and gasification systems capable of co-generating steam and electricity from lignite were contacted regarding their interest in providing cost and emissions information for the present study. In general, these technology providers and system manufacturers fell into two categories: large utility applications and small industrial applications. The proposed lignite application for ethanol plants is fairly small by industry standards, and as such falls into a niche category. Most coal-fired combustion or gasification systems are an order of magnitude larger than what is being proposed here. On the other end of the spectrum are small gasification systems which are an order of magnitude smaller than what is being considered here. At 60 MW equivalents, the proposed application for ethanol production falls distinctly between the utility (>400MW) and small industrial offerings (1-10 MW).

Of the large utility system providers, BBI contacted vendors of combustion technologies including Foster-Wheeler, Babcock & Wilcox, and Westinghouse. Foster-Wheeler and Westinghouse responded positively, and agreed to provide pricing and emissions information for small gasification systems they are marketing for applications like this. Babcock & Wilcox opted out as the application is too small for their systems.

Among the large utility-scale gasification vendors, BBI contacted Shell (representing the Krupps-Uhde process), Allied Recourses (representing the BGL-Lurgi process), ChevronTexaco, and ConocoPhillips (formerly Destec). Shell responded that their systems only become profitable at scales over 1,500 tons per day (5-times the scale of our study). ChevronTexaco and ConocoPhillips opted out as they did not see a good technology fit. Allied Resources would not provide costs for such a small system but indicated interest in a BOO (build-own-operate) scenario where they would install a much larger system and simply sell the ethanol plant syngas to replace its natural gas requirement.

Of the smaller existing and emerging vendors of lignite combustion technologies, Energy Products of Idaho (EPI) was highly recommended and provided costs for the study. Primenergy, an established gasification system provider also responded, as did Omnifuels, Thermogenics, and Westinghouse-Plasma. Detroit-Stoker and Von Roll are established boiler system vendors that also agreed to supply data for the study.

At this time, the companies who have provided cost and emissions data are EPI, Primenergy, Foster-Wheeler, Omnifuels, and Westinghouse-Plasma. The information from Foster-Wheeler, Detroit Stoker and Von Roll has not yet been received. Regardless of the technology or system provider selected, a lignite-fired co-generation system for an ethanol plant would be custom-designed for the specific application. It would be an equipment-intensive operation requiring a much larger initial capital investment that

offers the tradeoff of reduced operating costs, a reliable energy supply and a stable long term fuel price.

The following table summarizes the preliminary cost information received to date. Based on their demonstrated experience and systems in place, it is BBI's opinion that the EPI and Primenergy information is the most reliable. Based on the detail provided and industry reputation, BBI used the EPI numbers in the financial analysis as representative and mid-range with respect to capital cost.

Table 45 – Cost Estimates for Lignite Co-Generation Systems

Vendor	Technology	Status of Technology	Capital Cost Estimate ($MM)		
			15 MMGPY	30 MMGPY	40 MMGPY
EPI	FBC	Commercial	16.3	21.4	26.3
Primenergy	FBG	Commercial	15	25	33
Foster -Wheeler	CFBC	Commercial	10	14	16.8
Westinghouse - Plasma	FBG	Emerging	8	12	16
Omnifuels	FBG	Emerging	2.6	5.7	7.0

Additional details regarding the production costs and labor requirements of the cogeneration system are provided in the section presenting the results of the financial analysis.

Foster-Wheeler Process Description

The Foster Wheeler North America Corp. (FWNA) CFB combustion system operates on the circulating fluidized bed concept. Fuel and limestone are fed into the lower portion of the combustion chamber into a stream of fluidizing air. In this turbulent environment, the fuel and limestone are mixed quickly and uniformly with the bed material. The fluidizing air causes the fuel, limestone and bed material to circulate and rise throughout the combustion chamber and enter the hot cyclone separator. At that point, any unburned solids, including any unburned fuel, are captured and returned to the combustion chamber through a non-mechanical loopseal.

The limestone in the fuel mixture reacts with the sulfur dioxide and other sulfur compounds in the fuel gas, and the resulting inert solid material (CaSO4, calcium sulfate or gypsum) is removed with the ash. The high content of gypsum in the ash has numerous beneficial uses such as soil amendments, sludge stabilization, and cement additives.

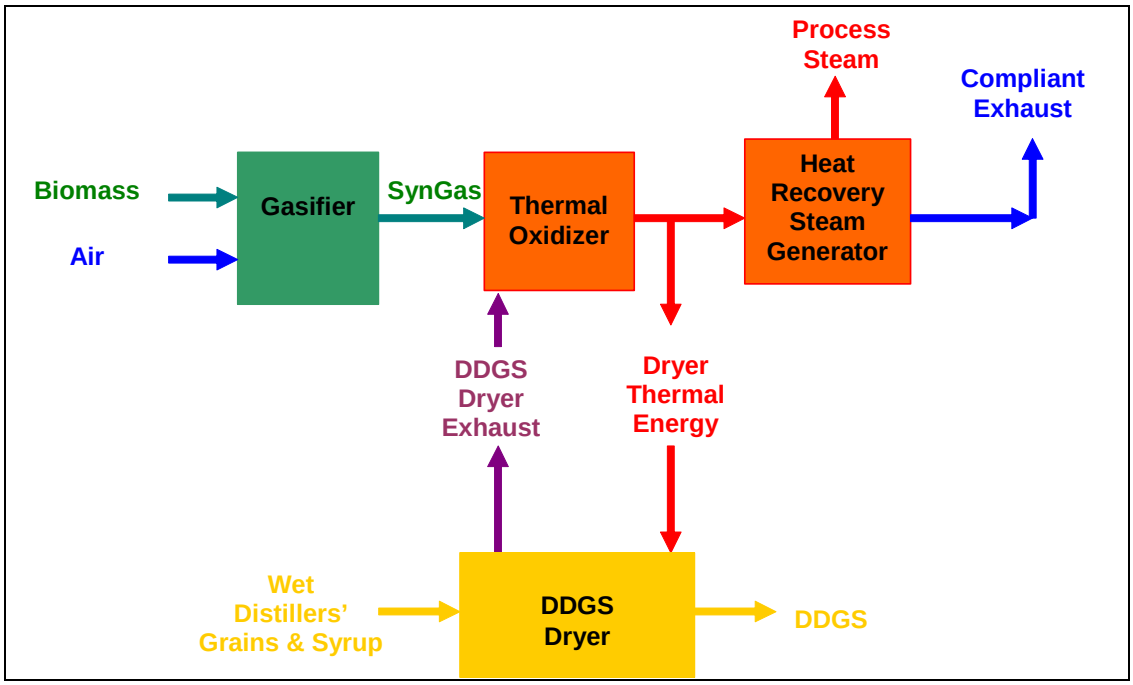
The fuel is burned at relatively low temperatures (1550-1650°F or 850-900°C), and because secondary air is introduced into the furnace at various levels above the grid, combustion occurs evenly throughout the combustion chamber. This low-temperature, staged combustion limits the formation of oxides of nitrogen (NOx). From the convection zone, flue gases pass through a particulate collection system and then induced draft fans carry the gases to the stack.

Primenergy Process Description

The following is a process description that Primenergy provided with their equipment estimate. It summarizes the proposed integrated gasification and ethanol production application succinctly. Primenergy's system is designed to utilize lignite and other biomass fuels.

Gasification is the thermochemical conversion of an organic solid into a combustible gas. Applying gasification technology to supply the auxiliary fuel for thermal oxidation eliminates the need for fossil fuel and stabilizes energy costs. The block flow diagram which follows depicts this unique process arrangement.

Figure 23 – Primenergy's Block Flow Diagram of Integrated Gasification and Ethanol Production



The heart of the process is an atmospheric updraft gasifier manufactured by Primenergy. This gasifier will gasify lignite and produce a synthesis gas, with calorific constituents consisting primarily of carbon monoxide and hydrogen. The lignite will be bought from a local mine, which will supply lignite to the project's specifications.

Hot combustible synthesis gas leaving the gasifier will be directed to a thermal oxidizer and mixed with the DDGS dryer exhaust. The synthesis gas is combusted in the thermal oxidizer and thermally converts the VOC contained in the dryer exhaust into carbon dioxide and water. Exiting the thermal oxidizer, the hot combustion products are split and sent to both a heat recovery, steam generator and back to the DDGS dryer.

The steam generator recovers thermal energy to produce high-pressure, superheated steam (600 psig and 800 ºF). The second stream of combustion products exiting the thermal oxidizer is supplied as the thermal energy requirement for the DDGS dryer. High-pressure steam from the HRSG will be first sent to a backpressure steam turbine to generate the electrical power for the plant. The steam exiting the turbine will be at a lower pressure of about 150 psig. The ethanol plant will use this lower pressure steam for its processes.

The combination of biomass gasification and thermal oxidation provides not only a unique solution for environmental compliance, but displaces the entire fossil fuel requirement for the ethanol plant. This process arrangement will ensure an extremely clean exhaust capable of meeting any emissions guideline, and eliminates fossil fuel consumption from ethanol manufacturing.

Process flow diagrams for the proposed Primenergy technology application are shown on the next two pages.

Figure 24 – Primenergy Inc. Co-Generation Process Flow Diagram

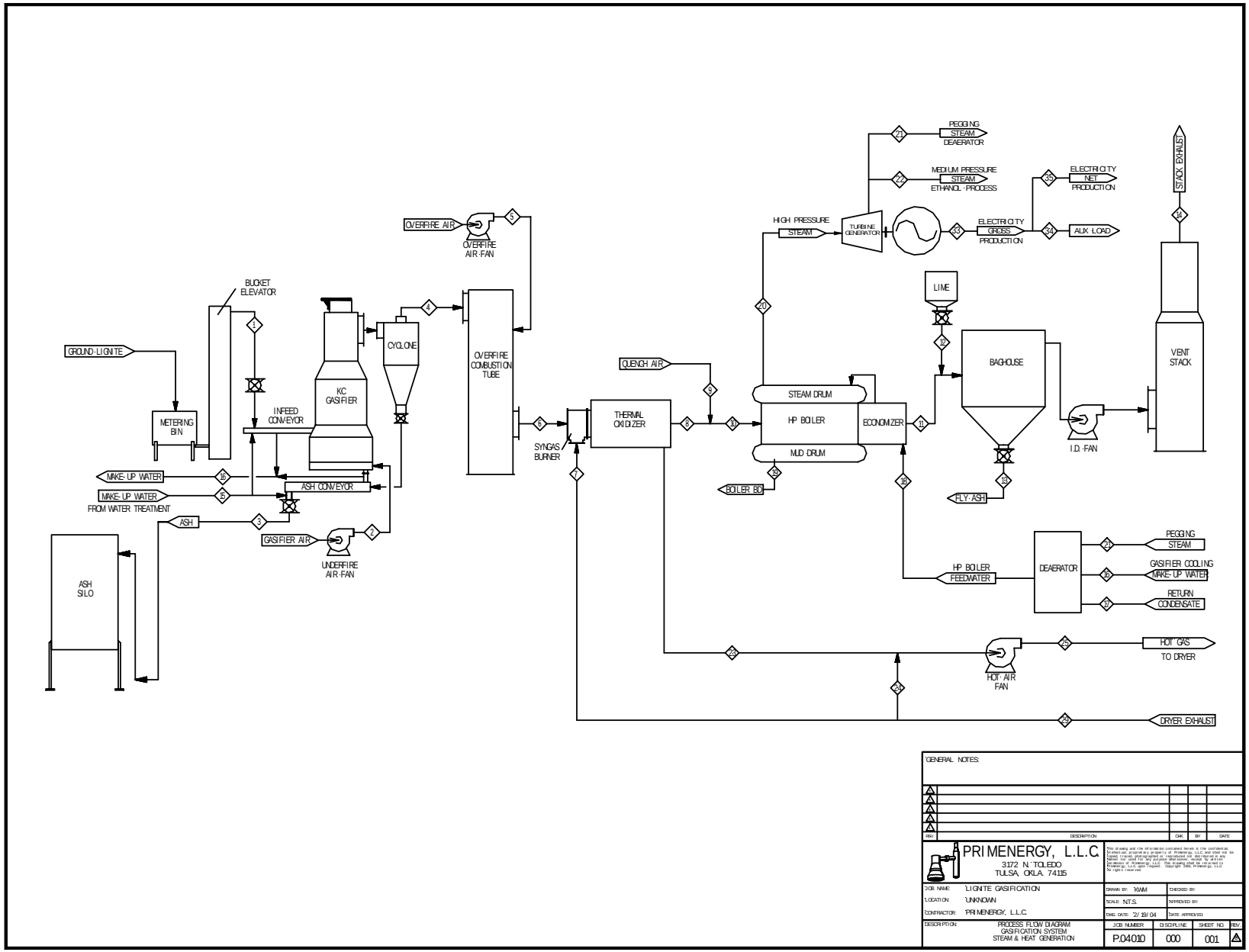
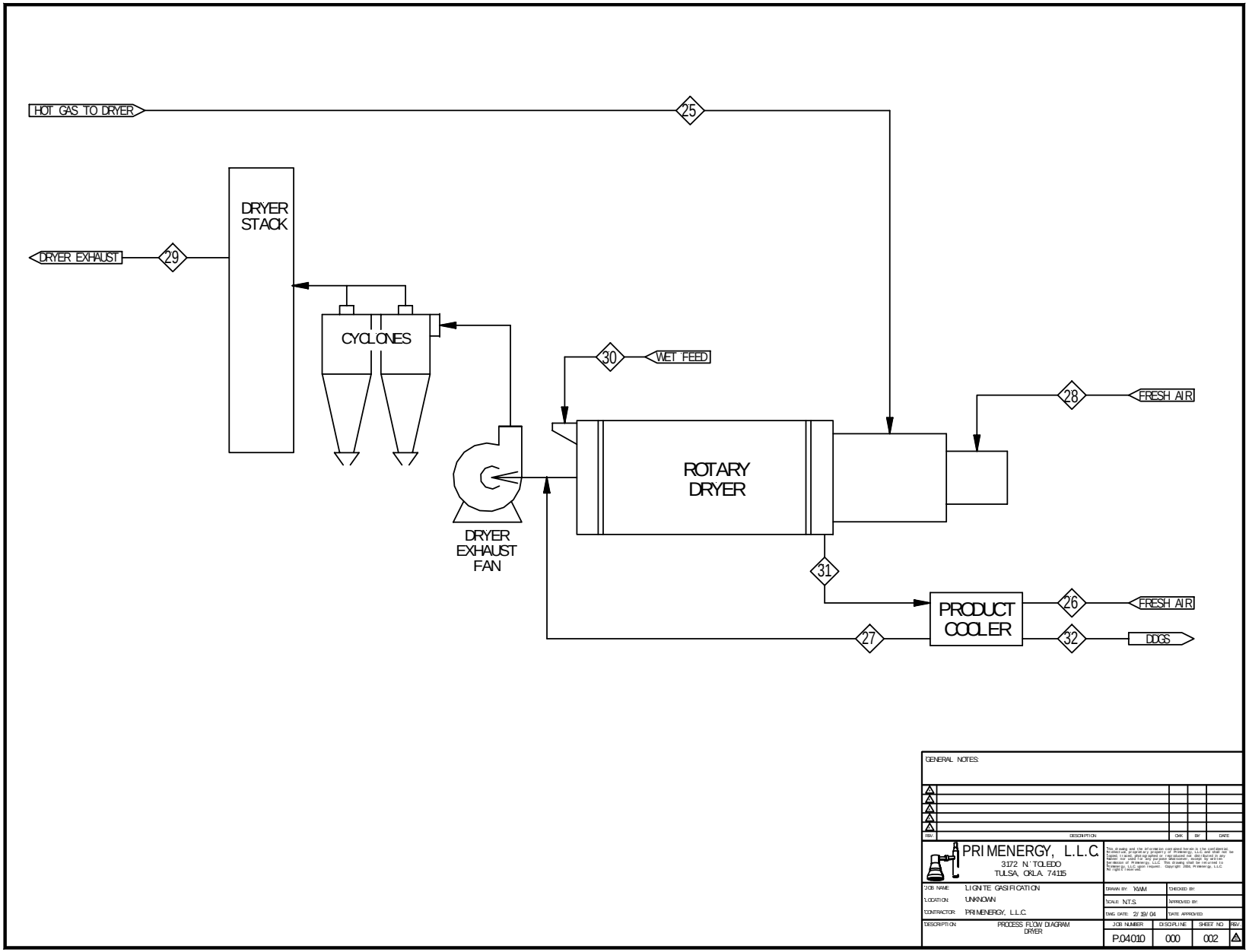


Figure 25 – Primenergy DDGS Drying Process Flow Diagram



Overview of Emissions Requirements, Equipment, Compliance

Emissions Requirements

The North Dakota Department of Health controls the permitting of industrial plants in the state of North Dakota. Obtaining a permit is basically a three-step process. The first step is to run a simple particulate and emission atmospheric dispersion model. If the model predicts that emissions will be under the limits of 250 tons/year SO_2, 100 tons/year of NO_x, and 100 tons/year of particulates, then the process goes forward relatively quickly. If the model predicts emissions will exceed any of the allowable limits, a more sophisticated atmospheric dispersion model is required to be run.

If this second model predicts that all emissions will be under the prescribed limits, the process goes forward rather quickly and a permit should be obtainable within about three to four months. If the second model predicts any emissions will be above allowable limits, then the facility is designated as a major "prevention of significant deterioration" (PSD) site. Major PSD sites must go through a "best available control technology" (BACT) analysis to determine the best overall technology fit for controlling the offending emissions. The BACT analysis process can usually be completed in about 12 months. It is likely that any coal-fired ethanol plant with an annual capacity of about 25 million gallons or more would be considered a major PSD site, on the basis of expected emissions.

North Dakota regulations for small coal-fired boilers stipulate a particulate emission maximum of 0.05 pounds per million Btu (lb/MMBtu), 90% reduction of sulfur dioxide (SO_2) in the boiler and a maximum SO_2 emission of no more than 1.2 lb/MMBtu, and a maximum oxides of nitrogen (NO_x) emission of 0.2 lb/MMBtu. Meeting these requirements would necessitate the use of an electrostatic precipitator for particulate emission control, a wet scrubber for SO_2, and possibly a selective catalytic reduction (SCR) unit for NO_x. The estimated total equipment cost for these items would be about $4 to $6 million.

Pollution Control Equipment

The following is taken from a recent article written by Masaki Takahashi of the World Bank.

Since coal typically contains 10–20 percent ash, flue gas contains particulates that must be collected before the gases are emitted. The electrostatic precipitator (ESP) is the most commonly used collection technology for electrical power utilities, but the wet scrubber is used with smaller units (200 MW or less). The wet scrubber has less collecting efficiency than the ESP (below 96 percent) and does not meet the guidelines set by the World Bank (50 mg/Nm3) as a primary measure of particulate control. But when the wet scrubber is installed as a measure to control SO2 and as an auxiliary to the ESP for particulate control, overall efficiency rises and particulate emissions fall.

The electric resistivity of ash affects the ESP's performance. Moisture, sulfur, sodium, and potassium reduce this resistance and are favorable to ash collection in an ESP. On the other hand, calcium and magnesium hamper ash collection and increase outlet emissions. Several steps can be taken to counter the problem associated with high resistivity ash and maintain performance at acceptable levels. These include intermittent charges; pulse charges; conditioning the flue gas with moisture, sulfur, or ammonium injection; and increasing the size of the ESP by widening the plate space. The capital cost of ESP technology is around 5 percent of the total plant or between $40 to $50 per kW.

After particulates, SO2 is usually the next target in reducing polluting emissions. Flue gas desulfurization (FGD) is a well-established method of removing SO2 from flue gas and has been widely used in electric utility plants in Europe, Japan, and the United States since the 1970s. The technology therefore has a long history and has been fine-tuned to optimize performance. New and simplified FGD technologies have been proposed and demonstrated in China and other developing countries.

The limestone-gypsum type of FGD is widely used, because affordable limestone is readily available at many locations throughout the world. Limestone is converted into gypsum by absorbing SO2 from flue gas. Gypsum can be used as wall board or can be sold as a byproduct where such demand exists. With the recent development of competitive markets and new technologies, the auxiliary power consumption and costs of FGD systems have been drastically reduced. FGD systems used to consume 3 percent or more of a plant's auxiliary power but now can operate on as little as 1–1.5 percent. Five years ago the cost of an FGD system was reported at $150–200/kW, but today that cost has fallen to $70–120/kW.

Coal-fired power stations also generate nitrogen oxide (NOx). Unlike particulate and SO2 emissions, NOx emissions are affected by the combustion process as well as the quality of the coal. Modifying the combustion process by optimizing the air flow from the burner can reduce NOx emissions by 20–30 percent at a relatively low cost ($5–10/kW). This low-cost option is the first that should be applied in existing plants. Two-stage combustion and a low-NOx burner are the next step in further reducing these emissions and can sometimes result in a 40–60 percent decline in NOx. These technologies are also relatively cheap to apply to new units ($5–10/kW), and the cost is modest ($10–20/kW) when they are applied to existing units.

Selective catalytic reduction (SCR) is a well-established approach to further reducing NOx emissions. It typically reduces these emissions by 80 percent, at a cost of $40 to $80/kW. Because SCR has been applied to commercial plants in Europe and Japan since the 1980s, it has over 15 years of successful operating experience. The operation and maintenance processes have been established, including slip ammonium control and catalyst life estimation.

Atmospheric fluidized-bed combustion (AFBC) has been widely applied to use low-grade coal or waste (opportunity fuel) at electric utility plants in the United States, Europe, and Japan since the 1980s. Hundreds of commercial plants are now in operation. The

maximum unit size has been limited to around 200 MW, but a few 350 MW units have been built in Japan and France. AFBC can remove SO2 during the combustion process when limestone is used with the fuel. Because the combustion temperature is lower (850ºC) with this technology, it generates relatively low NOx emissions. Particulate emissions are controlled either by ESP or bagfilter. The capital costs of AFBC are estimated at $1,000 – 1,300 /kW, a competitive price when SO2 control is required and low-grade fuel is available.

Compliance

For the present request for information, EPI assumed that the gas cleanup requirements would include SNCR (ammonia injection) for NOx and limestone and spray dryer for SOx and HCl. In all cases, EPI assumed the emission limits would be 100 TPY. In the words of EPI, "for the 40 MMGPY case, the NOx levels required for that emission limit may be a bit of a stretch, but all others look to be reasonable and readily achievable."

Primenergy reported the emissions estimates listed below for 15, 30 and 40 MMGPY ethanol plants corresponding to 5.8, 11.5 and 15.3 tons of lignite per hour.

Table 46 – Emissions Estimates for Primenergy Gasification Systems

Predicted Annual Emissions (TPY)				
Plant Capacity	**15 MMGPY**	**30 MMGPY**	**40 MMGPY**	**Limit for Minor Source**
Nitrogen Oxides	75	150	200	100
Sulfur Oxides	90	180	240	250
Carbon Monoxide	15	30	40	100
Volatile Organics	10	20	26.7	100
Particulate Matter	15	30	40	100
Chlorine	3	6	8	--

The Primenergy estimates show NO_x emissions potentially exceeding requirements for a minor source at the 30 and 40 MMGPY plant scales. They also qualified this information, saying:

> "The above air pollution concentrations are preliminary and extrapolated from representative feed composition and are additive to background levels. Lower levels of emissions can be achieved should they be required for site-specific permit conditions. However, additional equipment and costs will be required and incurred."

Foster-Wheeler states that one of the attributes of their circulating fluidized bed combustion technology is the low emissions and specifically low NO_x. According to Foster Wheeler:

> "CFBs do not require complicated and expensive downstream flue gas desulfurization-equipment to meet environmental regulations. Foster Wheeler has a majority of CFB installations operating at over 90% SO_2 capture, with many operating above 95% SO_2 capture. To achieve SO_2 capture, limestone is injected into the furnace and reacts with the sulfur dioxide and other sulfur compounds in the flue gas to form an inert dry solid, calcium sulfate ($CaSO_4$), or more commonly called gypsum. This dry solid is a reusable by-product such as an additive for the cement industry, soil amendment for acidic soils, sewage sludge neutralizer and stabilizer."

> "Emissions of nitrous oxides (NOx) are very low with a Foster Wheeler CFB boiler since they operate at low furnace temperatures that essentially eliminates the formation of thermally generated NOx, a major source of NOx."

At this early stage of project definition, none of the vendors contacted were willing to do more than a conceptual estimate of projected emissions due to their costs for engineering analysis and testing. However, based on the lignite analyses forwarded by BBI for their consideration, none expressed any unusual expectations for emissions control, and each provided a conceptual level solution or specification. BBI accepted their recommendations for emissions control equipment (based on the lignite analyses forwarded to each vendor by BBI), as they are best prepared to evaluate and provide this information for their respective equipment systems.

Based on the information gathered to date, it is BBI's conclusion that the emissions requirements can be met, but that additional cost may be incurred to meet NO_x requirements at the larger plant scales. Any additional expense or extra permit requirements would need to be taken into consideration should a decision be made to pursue the project.

Increased Lignite Usage based on Ethanol Production

Substituting lignite for natural gas as the principal energy source for an ethanol production plant or plants will not significantly increase lignite utilization because the ethanol plants are miniscule consumers compared with power industry standards. Even at the 40 MMGPY plant scale, only about 128,500 tons of new production would be utilized annually. This represents an increase in lignite utilization of 0.33% of total annual lignite production for each 40 MMGPY plant designed to use lignite.

It should be noted that, while 80% of the state's lignite production is used in power generation, 20% is used to in the production of synthetic natural gas.

In addition, if electricity were generated at the lignite-fired power plant, then the coal conversion tax associated with electricity generation would be paid to the state, whereas, if the electrical power were generated at the corn-to-ethanol plant as part of a small-scale cogeneration system, the coal conversion tax would not be paid to the state.

As will be noted later in this report, one potential option to improve the economics of a lignite-fired ethanol facility is to increase the scale of the power production side of the equation. By increasing the power production scale from the 5 MW scale associated with the 40 MMGPY ethanol plant, up to the 100 or 200 MW scale associated with power industry standards, the capital expense would be removed from the ethanol project costs, and replaced with an over-the-fence dedicated customer/supplier relationship. This option would replace the long term potential for reducing production costs associated with on-site power and steam co-generation with a long-term supply of cheap steam and power, supplied at a rate equivalent to about 50-75% of the average price of natural gas. This type of arrangement would boost lignite utilization significantly, into the range of 2-4 million tons per year, representing an increase in total annual production of 6.5-13%.

An additional 200 MW of lignite-fired electrical generation would generate approximately $1,070,000 per year in additional tax revenues for the state from the increase in electricity generation.

A second alternative would be to co-locate an ethanol plant(s) at the existing power stations(s) associated with one of the principal lignite mines. This would be an opportunity to purchase steam and electricity from the existing utility plant at a price beneath the equivalent amount of natural gas, thereby reducing the cost of production for the ethanol plant. This might also create an opportunity to export the DDGS drier exhaust to the power plant for use as make up air, eliminating the capital cost of the thermal oxidizer from the ethanol project. Such a co-location scenario might also allow use of the ethanol plant's effluent as makeup water for steam production or other uses by the power plant.

IX. FINANCIAL ANALYSIS

BBI's financial model for dry mill ethanol production was used to estimate the financial performance of each of the five proposed ethanol plants, first with lignite fired cogeneration and then again with purchased natural gas and electricity for comparison. Ethanol plant sizes of 10, 30 and 40 million gallons per year (MMGPY) of denatured ethanol production were modeled for the five sites site.

The financial analysis includes all significant plant inputs and outputs that affect the potential profitability of the project. These include ethanol production costs, ethanol and byproduct revenues, capital costs including project development, financing, construction, start-up, working capital and inventory costs. The capital and operating cost estimates obtained by BBI for the cogeneration power plant were included in the analysis.

Sensitivity studies were performed for the cost of corn and barley, ethanol price, distillers grain price, lignite price, natural gas price and the capital cost of the cogeneration facility. The model produces a ten-year operating forecast for the project. The complete 10-year proforma results are included in the appendix of this report.

Assumptions Used in the Financial Forecast

For the purpose of this feasibility study, the feedstock is assumed to be corn for sites #1, #2, #4 and #5. Site #3 is assumed to use barley. The composition of corn and barley used for the analysis is shown in the table below. The approximate ethanol and distillers grain yields used in the analysis are shown in Table 47.

Table 47 – Approximate Composition and Yield Data for Corn and Barley

	Starch (dry basis)	Protein (dry basis)	Ethanol Yield (gal/bushel)	DDGS Yield (lb/bushel)
Corn	71%	9%	2.80	18.0
Barley	65%	13%	2.31	19.0

Corn bushel = 56 lbs, 14% moisture. Barley Bushel = 48 lbs, 12% moisture.
Ethanol and DDGS yields based on average yields for new dry mill ethanol plants, DDGS at 10% moisture. Ethanol yield is denatured ethanol.

The major variables for the financial analysis are ethanol price, feedstock price, distillers grain drying and price, energy costs and capital costs. In addition to these parameters, various financial model input sensitivities were analyzed and are described below. The assumptions used in the financial forecasts that have the greatest impact on the project risk and return are:

- *Ethanol Price*. The ethanol price used in the financial forecast is $1.27 per gallon of denatured ethanol. The net back to the plant will be $1.27 minus the average

shipping cost of $0.097 per gallon and minus a sales commission of 1% of the ethanol sales price. The primary market for North Dakota ethanol is assumed to be the West Coast where ethanol prices have averaged $1.27 per gallon over the past ten years. The impacts of higher and lower ethanol prices will be determined.

- *Feedstock Price*. Grain prices used in the financial analysis are based on the 10-year average price of corn in North Dakota. The 10-year average was adjusted for each site based on 2000–2001 average elevator prices provided by the North Dakota Corn Growers' Association. A basis increase of $0.05 per bushel is also included in the estimated corn and barley prices. The resulting site-specific corn and barley prices are listed in the table blow.

Table 48 – Location-Specific Estimated Corn Prices ($/bushel)

Site #1 Hankinson	Site #2 Valley City	Site #3 Minot	Site #4 Beulah	Site #5 Richardton
$2.28	$2.08	$1.84*	$2.54	$2.58

** The price for site # 3 is for barley; all other prices are for corn.*
Prices shown include a $0.05 per bushel increase in local basis after plant startup

- *Distillers Grain Price*. Local prices for distillers dry grain and solubles (DDGS) are assumed to follow the site specific corn prices with the DDGS price set at 105% of the local corn price on a dry weight basis. The resulting DDGS prices are as follows:

Table 49 – Location-Specific Estimated DDGS Prices ($/ton)

Site #1 Hankinson	Site #2 Valley City	Site #3 Minot	Site #4 Beulah	Site #5 Richardton
$90.53	$85.37	$85.24	$96.49	$96.49

Prices shown are 103% of the local corn prices on a dry weight basis

- *Wet Distillers Grain*. The local market for wet distillers grain appears to be substantial, but the financial analysis will take the more conservative approach and assume that all of the distillers grain is dried and sold as DDGS.

- *State Producer Payment.* The financial forecast includes a state producer payment of $400,000 per year for ethanol production. This amount could be higher or lower depending upon the price of corn, the price of ethanol and the number of new plants applying for the $1.6 million annual allocation. To calculate the state payments, we have assumed that on average the statewide average price of corn in North Dakota will be $2.10 per bushel and the average rack price of gasoline used

to compute the payments will be $1.25 per gallon. This works out to a payment of $0.04 per gallon of ethanol.

- *Federal Small Producer Tax Credit.* The financial forecast does not include the Federal Small Producer Tax Credit except for site #3, which at 10 MMGPY would qualify for the credit. The credit is 10¢ per gallon on the first 15 million gallons of ethanol produced annually ($1.5 million annually). The credit is currently scheduled to expire at the end of 2007, but it is likely that the credit will be extended beyond 2007. The credit also currently only applies to plants that produce 30 million gallons per year or less, but legislation pending in the U.S. Congress would allow plants up to 60 MMGPY to qualify for the credit. To simplify the financial calculations when included in the financial forecast, the Federal Small Producer Tax Credit is assumed to be a payment to the project. The "value" of the tax credit when viewed as income is reduced to about 7¢ per gallon rather than the full 10¢ per gallon tax credit (the credit is considered taxable income and taxes must be paid on the amount credited).

- *Financing*. For the present study, BBI used 100% equity.

- *Natural Gas Price.* The lignite-fired cogeneration project scenarios do not require natural gas. We have included a small annual cost for natural gas or propane for preheating the lignite combustion chamber (if necessary) and other uses. The cost is about $300,000 per year for the 40 MMGPY plant and proportionately less for the smaller plants. We have assumed a price of $5.00 per million Btu for the backup fuel. For the comparison with natural gas, we have used the DOE EIA projections as outlined earlier in the report.

- *Electricity Price.* We have assumed that the ethanol plant will generate its own electricity and only standby charges for backup power are required. These charges are approximately $130,000 annually for the 40 MMGPY plant

- *Shuttle Train Facility and New Track Requirements.* Sites #4 and #5 in Beulah and Richardton are assumed to rail corn in from the east. The most cost effective way to do this is with a high-speed shuttle unloading facility. The capital costs for Beulah and Richardton have been increased $2.3 million to account for the additional cost for upgrading the grain unloading equipment, increasing the amount of grain storage and for the 8,000 foot unit train loop track.

A summary of the input parameters used in the financial analysis for the lignite-fired plant scenarios is provided in Table 50; the analogous summary of the input parameters used in the financial analysis for the natural gas-fired plant scenarios is provided in Table 51. A complete list of the input parameters for all scenarios is included in Appendix A.

Table 50 – Assumptions Used in the Financial Forecast for Lignite-Fired Plants

Model Input	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
Ethanol plant capital cost per gallon	$1.125	$1.15	$1.50	$1.125	$1.125
Ethanol yield (anhydrous gal/bu)	2.67	2.67	2.20	2.67	2.67
Grain Test Weight (lb/bu)	56.0	56.0	48.0	56.0	56.0
Ethanol selling price ($/gal)	$1.27	$1.27	$1.27	$1.27	$1.27
Ethanol transportation cost ($/gal)	$0.097	$0.097	$0.097	$0.097	$0.097
Ethanol sales commission (%)	1.00%	1.00%	1.00%	1.00%	1.00%
Delivered grain price ($/bu)	$2.28	$2.15	$1.84	$2.43	$2.43
Distillers grain drying (%)	100%	100%	100%	100%	100%
Distillers grain yield (lb/bu)	18.0	18.0	19.0	18.0	18.0
DDGS price ($/ton FOB Plant)	$90.53	$85.37	$85.24	$96.49	$96.49
DDGS sales commission (%)	2.00%	2.00%	2.00%	2.00%	2.00%
Carbon dioxide (CO2) price ($/ton)	$0.00	$0.00	$0.00	$0.00	$0.00
Lignite use (tons/year)	128,500	96,300	32,100	128,500	128,500
Delivered lignite cost ($/ton)	$23.00	$20.00	$23.00	$14.00	$17.00
Lime & limestone use (ton/year)	32,000	24,000	8,000	32,000	32,000
Lime & limestone price ($/ton)	$23.00	$23.00	$23.00	$23.00	$23.00
Makeup water use(gal/bu)	12.0	12.0	12.0	12.0	12.0
Makeup water price ($/1000 gal)	$1.00	$1.00	$1.00	$1.00	$1.00
Wastewater effluent (gal/bu)	2.4	2.4	2.4	2.4	2.4
Wastewater effluent cost ($/1000 gal)	$2.00	$2.00	$2.00	$2.00	$2.00
Denaturant use (%)	4.76%	4.76%	4.76%	4.76%	4.76%
Denaturant price ($/gal)	$0.70	$0.70	$0.70	$0.70	$0.70
Chemicals & enzymes ($/gal ethanol)	$0.07	$0.07	$0.09	$0.07	$0.07
Number of employees	51	49	35	51	51
Maintenance materials (% of Capital)	2.00%	2.00%	2.00%	2.00%	2.00%
Property tax & insurance (% of Cap.)	1.50%	1.50%	1.50%	1.50%	1.50%
Senior Debt (% of Total Project Costs)	0%	0%	0%	0%	0%
Equity (% of Total Project Costs)	100%	100%	100%	100%	100%
Loan Interest Rate (%)	NA	NA	NA	NA	NA
Loan term (years)	NA	NA	NA	NA	NA
Land Required (acres)	40	40	20	40	40
Land Price ($/acre)	$2,500	$2,500	$2,500	$2,500	$2,500

Note: The feedstock for Site #3 is barley, all others are corn

Table 51 – Assumptions Used in the Financial Forecast for Natural Gas-Fired Plants

Model Input	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
Ethanol plant capital cost per gallon	$1.125	$1.15	$1.50	$1.125	$1.125
Ethanol yield (anhydrous gal/bu)	2.67	2.67	2.20	2.67	2.67
Grain Test Weight (lb/bu)	56.0	56.0	48.0	56.0	56.0
Ethanol selling price ($/gal)	$1.27	$1.27	$1.27	$1.27	$1.27
Ethanol transportation cost ($/gal)	$0.097	$0.097	$0.097	$0.097	$0.097
Ethanol sales commission (%)	1.00%	1.00%	1.00%	1.00%	1.00%
Delivered grain price ($/bu)	$2.28	$2.15	$1.84	$2.43	$2.43
Distillers grain drying (%)	100%	100%	100%	100%	100%
Distillers grain yield (lb/bu)	18.0	18.0	19.0	18.0	18.0
DDGS price ($/ton FOB Plant)	$90.53	$85.37	$85.24	$96.49	$96.49
DDGS sales commission (%)	2.00%	2.00%	2.00%	2.00%	2.00%
Carbon dioxide (CO2) price ($/ton)	$0.00	$0.00	$0.00	$0.00	$0.00
Annual natural gas use (MCF/yr)	1,450,935	1,088,202	362,734	1,450,935	1,450,935
Natural gas price ($/MCF)	EIA Forecast	EIA Forecast	EIA Forecast	EIA Forecast	EIA Forecast
Makeup water use(gal/bu)	12.0	12.0	12.0	12.0	12.0
Makeup water price ($/1000 gal)	$1.00	$1.00	$1.00	$1.00	$1.00
Wastewater effluent (gal/bu)	2.4	2.4	2.4	2.4	2.4
Wastewater effluent cost ($/1000 gal)	$2.00	$2.00	$2.00	$2.00	$2.00
Denaturant use (%)	4.76%	4.76%	4.76%	4.76%	4.76%
Denaturant price ($/gal)	$0.70	$0.70	$0.70	$0.70	$0.70
Chemicals & enzymes ($/gal ethanol)	$0.07	$0.07	$0.09	$0.07	$0.07
Number of employees	36	34	20	36	36
Maintenance materials (% of Capital)	2.00%	2.00%	2.00%	2.00%	2.00%
Property tax & insurance (% of Cap.)	1.50%	1.50%	1.50%	1.50%	1.50%
Senior Debt (% of Total Project Costs)	0%	0%	0%	0%	0%
Equity (% of Total Project Costs)	100%	100%	100%	100%	100%
Loan Interest Rate (%)	NA	NA	NA	NA	NA
Loan term (years)	NA	NA	NA	NA	NA
Land Required (acres)	40	40	20	40	40
Land Price ($/acre)	$2,500	$2,500	$2,500	$2,500	$2,500

A breakdown of the lignite-fired ethanol plant capital costs and the owner's costs is presented in Table 52; the analogous breakdown of the natural gas-fired ethanol plant capital costs and the owner's costs is presented in Table 53.

Table 52 – North Dakota Lignite-Fired Ethanol Project Capital Cost Estimates

	Plant #1	Plant #2	Plant #3	Plant #4	Plant #5
Plant Nameplate Design Capacity (gal/year)	**40,000,000**	**30,000,000**	**10,000,000**	**40,000,000**	**40,000,000**
Project Engineering & Construction Costs					
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Cogeneration System	$26,300,000	$21,400,000	$12,200,000	$26,300,000	$26,300,000
Total Engineering and Construction Cost	**$71,300,000**	**$55,900,000**	**$27,200,000**	**$73,600,000**	**$73,600,000**
Owners Costs					
Inventory - Grain	$854,000	$624,000	$217,000	$910,000	$910,000
Inventory - Chemicals/Yeast/Denaturant	$404,000	$288,000	$112,000	$345,000	$365,000
Inventory - Ethanol & DDGS	$912,000	$668,000	$247,000	$934,000	$942,000
Inventory - Spare Parts	$750,000	$750,000	$500,000	$750,000	$750,000
Startup Costs	$1,000,000	$1,000,000	$800,000	$1,000,000	$1,000,000
Land	$100,000	$100,000	$50,000	$100,000	$100,000
Administration Building & Furnishing	$300,000	$300,000	$200,000	$300,000	$300,000
Rail Improvements	$950,000	$850,000	$600,000	$950,000	$950,000
Water Treatment	$600,000	$500,000	$300,000	$600,000	$600,000
Site Development Costs	$1,500,000	$1,300,000	$700,000	$1,500,000	$1,500,000
Rolling Stock and Shop Equipment	$400,000	$400,000	$300,000	$400,000	$400,000
Organizational Costs	$1,100,000	$1,000,000	$600,000	$1,100,000	$1,100,000
Capitalized Fees and Interest	$1,900,000	$1,500,000	$750,000	$1,900,000	$1,900,000
Contingency	$1,000,000	$800,000	$500,000	$1,000,000	$1,000,000
Total Owners Costs	**$11,770,000**	**$10,080,000**	**$5,876,000**	**$11,789,000**	**$11,816,000**
Total Project Capital Cost	**$83,070,000**	**$65,980,000**	**$33,076,000**	**$85,389,000**	**$85,416,000**

Table 53 – North Dakota Natural Gas-Fired Ethanol Project Capital Cost Estimates

	Site #1	Site #2	Site #3	Site #4	Site #5
Plant Nameplate Design Capacity (gal/year)	**40,000,000**	**30,000,000**	**10,000,000**	**40,000,000**	**40,000,000**
Project Engineering & Construction Costs					
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Cogeneration System	$3,000,000	$2,500,000	$1,100,000	$3,000,000	$3,000,000
Total Engineering and Construction Cost	**$48,000,000**	**$37,000,000**	**$16,100,000**	**$50,300,000**	**$50,300,000**
Owners Costs					
Inventory – Grain	$854,000	$624,000	$217,000	$910,000	$910,000
Inventory - Chemicals/Yeast/Denaturant	$207,000	$155,000	$63,000	$207,000	$207,000
Inventory - Ethanol & DDGS	$975,000	$721,000	$257,000	$1,021,000	$1,021,000
Inventory - Spare Parts	$450,000	$450,000	$300,000	$450,000	$450,000
Startup Costs	$750,000	$750,000	$600,000	$750,000	$750,000
Land	$100,000	$100,000	$50,000	$100,000	$100,000
Administration Building & Furnishing	$300,000	$300,000	$200,000	$300,000	$300,000
Rail Improvements	$950,000	$850,000	$600,000	$950,000	$950,000
Water Treatment	$600,000	$500,000	$300,000	$600,000	$600,000
Site Development Costs	$1,500,000	$1,300,000	$700,000	$1,500,000	$1,500,000
Rolling Stock and Shop Equipment	$400,000	$400,000	$300,000	$400,000	$400,000
Organizational Costs	$1,100,000	$1,000,000	$600,000	$1,100,000	$1,100,000
Capitalized Fees and Interest	$1,900,000	$1,500,000	$750,000	$1,900,000	$1,900,000
Contingency	$1,000,000	$800,000	$500,000	$1,000,000	$1,000,000
Total Owners Costs	**$11,086,000**	**$9,450,000**	**$5,437,000**	**$11,188,000**	**$11,188,000**
Total Project Capital Cost	**$59,086,000**	**$46,450,000**	**$21,537,000**	**$61,488,000**	**$61,488,000**

Economic Modeling Results for Lignite-Fired Ethanol Plants

Lignite-fired ethanol plants were modeled using BBI's proprietary financial model. Internal Rate of Return (IRR) and Net Present Value (NPV) with 8% and 15% discount rates were used to measure the profitability of the proposed projects. The results are summarized in Table 54. More detailed results are shown on the following pages and in the complete 10-year economic forecasts for each of the five sites, which are included in the appendix. The results shown are with 100% of the distillers grain sold dry. Sales of carbon dioxide are not included in the analysis.

Table 54 – Modeling Results for Lignite-Fired Ethanol Plants

	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
Internal Rate of Return	12.7%	11.0%	1.3%	11.4%	10.8%
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Cogen Plant Capital Cost	$26,300,000	$21,400,000	$12,200,000	$26,300,000	$26,300,000
Owner's Costs	$11,769,000	$10,080,000	$5,876,000	$11,788,000	$11,816,000
Total Project Investment	$83,069,000	$65,980,000	$33,076,000	$85,388,000	$85,416,000
Equity (100%)	$83,069,000	$65,980,000	$33,076,000	$85,388,000	$85,416,000
Net Present Value, 8% Discount Rate	$18,663,000	$9,217,000	($8,962,000)	$13,818,000	$11,305,000
Net Present Value, 15% Discount Rate	(6,768,000)	(9,170,000)	(13,824,000)	(10,671,000)	(12,420,000)

The analogous financial forecast and a comparative analysis for the five sites in this study with natural gas and purchased electricity are provided further in this section.

For the lignite-fired production scenarios, the proposed ethanol projects have a range of projected results, and the analysis predicts an NPV with an 8% discount rate ranging from a low of ($8,962,000) for the 10 MMGPY plant at site #3 to a high of $18,663,000 for the 40 MMGPY plant at site #1.

The estimated total project investment is $33.1 million for the 10 MMGPY plant, $66.0 million for the 30 MMGPY plant and $83.1 million for the 40 MMGPY plant.

Should some level of lignite economic development funds be made available to an ethanol plant facility, the level of assistant would probably be related to the annual lignite consumption. Assuming a "dollars-to-lignite tonnage" ratio similar to that of recent North Dakota Lignite Vision 21 grants, any award to an ethanol plant would likely be in the range of $350,000. However, this figure is just a guideline. All program awards are subject to proposal peer review evaluation, recommendation by the Lignite Research Council and funding approval by the NDIC.

Sensitivity and Breakeven Analysis

The variables that have the greatest impact on the project's profitability are the delivered price for corn and the ethanol selling price. This is the case for all fuel ethanol plants, not just the proposed North Dakota projects. A sensitivity analysis was run to determine the "breakeven" prices for corn and ethanol. Breakeven here is defined as the point where the projected average annual pre-tax income for commercial operating years 2 through 11 is zero.

The sensitivity analysis for the 40 MMGPY lignite-fired plant in Hankinson (site #1) is shown in Table 55. The sensitivity analysis for the 30 MMGPY lignite-fired plant in Valley City (site #2) is shown in Table 56 and the sensitivity analysis for the 10 MMGPY lignite-fired plant in Minot (site #3 using barley) is shown in Table 57.

Table 55 – Sensitivity Analysis for 40 MMGPY Lignite-Fired Ethanol Plant

Corn and Ethanol Price Sensitivity
10-Year Average Annual Pre-Tax Income
North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1

40 MMGPY Plant March 31, 2004

Corn ($/bushel)	Ethanol ($/gallon) 1.02	1.07	1.12	1.17	1.22	1.27	1.32	1.37	1.42	1.47	1.52
1.88	4,284,713	6,623,114	8,961,515	11,299,909	13,638,255	15,976,600	18,314,946	20,653,292	22,991,638	25,329,983	27,668,329
1.93	3,757,193	6,095,594	8,433,995	10,772,397	13,110,756	15,449,102	17,787,448	20,125,793	22,464,139	24,802,485	27,140,831
1.98	3,229,671	5,568,072	7,906,473	10,244,875	12,583,255	14,921,601	17,259,947	19,598,292	21,936,638	24,274,984	26,613,329
2.03	2,702,146	5,040,547	7,378,949	9,717,350	12,055,751	14,394,097	16,732,443	19,070,789	21,409,134	23,747,480	26,085,826
2.08	2,174,627	4,513,028	6,851,429	9,189,830	11,528,232	13,866,599	16,204,944	18,543,290	20,881,636	23,219,982	25,558,327
2.13	1,647,105	3,985,506	6,323,907	8,662,308	11,000,709	13,339,097	15,677,443	18,015,789	20,354,135	22,692,480	25,030,826
2.18	1,119,583	3,457,984	5,796,385	8,134,786	10,473,187	12,811,589	15,149,942	17,488,288	19,826,634	22,164,979	24,503,325
2.23	592,061	2,930,462	5,268,863	7,607,264	9,945,665	12,284,066	14,622,441	16,960,787	19,299,132	21,637,478	23,975,824
2.28	64,541	2,402,942	4,741,343	7,079,745	9,418,146	11,756,547	14,094,942	16,433,288	18,771,634	21,109,980	23,448,325
2.33	(462,981)	1,875,420	4,213,821	6,552,222	8,890,624	11,229,025	13,567,426	15,905,787	18,244,133	20,582,478	22,920,824
2.38	(990,503)	1,347,898	3,686,299	6,024,700	8,363,102	10,701,503	13,039,904	15,378,286	17,716,632	20,054,977	22,393,323
2.43	(1,518,025)	820,376	3,158,777	5,497,178	7,835,579	10,173,981	12,512,382	14,850,783	17,189,130	19,527,476	21,865,822
2.48	(2,045,547)	292,854	2,631,255	4,969,656	7,308,057	9,646,458	11,984,860	14,323,261	16,661,629	18,999,975	21,338,321
2.53	(2,573,067)	(234,666)	2,103,735	4,442,137	6,780,538	9,118,939	11,457,340	13,795,741	16,134,131	18,472,477	20,810,822
2.58	(3,101,562)	(762,190)	1,576,211	3,914,612	6,253,013	8,591,414	10,929,815	13,268,217	15,606,618	17,944,973	20,283,319
2.63	(3,721,291)	(1,289,710)	1,048,691	3,387,092	5,725,494	8,063,895	10,402,296	12,740,697	15,079,098	17,417,474	19,755,820
2.68	(4,514,263)	(1,817,232)	521,169	2,859,570	5,197,972	7,536,373	9,874,774	12,213,175	14,551,576	16,889,973	19,228,319

Table 56 – Sensitivity Analysis for 30 MMGPY Lignite-Fired Ethanol Plant

Corn and Ethanol Price Sensitivity
10-Year Average Annual Pre-Tax Income
North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2

30 MMGPY Plant March 31, 2004

Corn ($/bushel)	Ethanol ($/gallon) 1.02	1.07	1.12	1.17	1.22	1.27	1.32	1.37	1.42	1.47	1.52
1.75	2,795,846	4,549,647	6,303,448	8,057,241	9,811,001	11,564,760	13,318,519	15,072,278	16,826,038	18,579,797	20,333,556
1.80	2,400,204	4,154,004	5,907,805	7,661,606	9,415,373	11,169,133	12,922,892	14,676,651	16,430,411	18,184,170	19,937,929
1.85	2,004,563	3,758,364	5,512,165	7,265,966	9,019,749	10,773,508	12,527,267	14,281,027	16,034,786	17,788,545	19,542,305
1.90	1,608,923	3,362,724	5,116,525	6,870,326	8,624,124	10,377,884	12,131,643	13,885,402	15,639,162	17,392,921	19,146,680
1.95	1,213,280	2,967,081	4,720,882	6,474,683	8,228,484	9,982,256	11,736,016	13,489,775	15,243,534	16,997,294	18,751,053
2.00	817,640	2,571,441	4,325,242	6,079,042	7,832,843	9,586,632	11,340,391	13,094,151	14,847,910	16,601,669	18,355,428
2.05	422,000	2,175,800	3,929,601	5,683,402	7,437,203	9,191,004	10,944,767	12,698,526	14,452,285	16,206,045	17,959,804
2.10	26,359	1,780,160	3,533,961	5,287,762	7,041,563	8,795,364	10,549,142	12,302,901	14,056,661	15,810,420	17,564,179
2.15	(369,281)	1,384,520	3,138,321	4,892,122	6,645,923	8,399,723	10,153,518	11,907,277	13,661,036	15,414,796	17,168,555
2.20	(764,924)	988,877	2,742,678	4,496,479	6,250,280	8,004,081	9,757,881	11,511,650	13,265,409	15,019,168	16,772,928
2.25	(1,160,564)	593,237	2,347,038	4,100,839	5,854,639	7,608,440	9,362,241	11,116,025	12,869,785	14,623,544	16,377,303
2.30	(1,556,207)	197,594	1,951,395	3,705,196	5,458,997	7,212,797	8,966,598	10,720,398	12,474,157	14,227,917	15,981,676
2.35	(1,951,847)	(198,046)	1,555,754	3,309,555	5,063,356	6,817,157	8,570,958	10,324,759	12,078,533	13,832,292	15,586,051
2.40	(2,347,488)	(593,687)	1,160,114	2,913,915	4,667,716	6,421,517	8,175,318	9,929,119	11,682,908	13,436,668	15,190,427
2.45	(2,757,684)	(989,330)	764,471	2,518,272	4,272,073	6,025,874	7,779,675	9,533,476	11,287,277	13,041,040	14,794,800
2.50	(3,296,434)	(1,384,970)	368,831	2,122,632	3,876,433	5,630,234	7,384,035	9,137,835	10,891,636	12,645,416	14,399,175
2.55	(3,909,850)	(1,780,613)	(26,812)	1,726,989	3,480,790	5,234,591	6,988,392	8,742,193	10,495,993	12,249,789	14,003,548

Table 57 – Sensitivity Analysis for 10 MMGPY Lignite-Fired Ethanol Plant

Barley and Ethanol Price Sensitivity
10-Year Average Annual Pre-Tax Income
North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3

10 MMGPY Plant March 31, 2004

Corn ($/bushel)	Ethanol ($/gallon) 1.02	1.07	1.12	1.17	1.22	1.27	1.32	1.37	1.42	1.47	1.52
1.44	187,847	772,447	1,357,047	1,941,648	2,526,238	3,110,824	3,695,410	4,279,997	4,864,583	5,449,170	6,033,756
1.49	47,604	632,204	1,216,804	1,801,404	2,386,000	2,970,587	3,555,173	4,139,760	4,724,346	5,308,933	5,893,519
1.54	(92,634)	491,966	1,076,566	1,661,167	2,245,767	2,830,355	3,414,941	3,999,528	4,584,114	5,168,701	5,753,287
1.59	(232,872)	351,728	936,329	1,520,929	2,105,529	2,690,123	3,274,710	3,859,296	4,443,882	5,028,469	5,613,055
1.64	(373,115)	211,485	796,086	1,380,686	1,965,286	2,549,886	3,134,472	3,719,059	4,303,645	4,888,232	5,472,818
1.69	(513,353)	71,247	655,848	1,240,448	1,825,048	2,409,649	2,994,241	3,578,827	4,163,413	4,748,000	5,332,586
1.74	(653,591)	(68,990)	515,610	1,100,210	1,684,810	2,269,411	2,854,009	3,438,595	4,023,182	4,607,768	5,192,354
1.79	(793,831)	(209,231)	375,369	959,970	1,544,570	2,129,170	2,713,771	3,298,361	3,882,947	4,467,534	5,052,120
1.84	(934,072)	(349,471)	235,129	819,729	1,404,330	1,988,930	2,573,530	3,158,126	3,742,713	4,327,299	4,911,885
1.89	(1,074,309)	(489,709)	94,891	679,492	1,264,092	1,848,692	2,433,292	3,017,893	3,602,481	4,187,067	4,771,654
1.94	(1,214,550)	(629,949)	(45,349)	539,251	1,123,851	1,708,452	2,293,052	2,877,652	3,462,246	4,046,833	4,631,419
1.99	(1,354,790)	(770,190)	(185,590)	399,011	983,611	1,568,211	2,152,812	2,737,412	3,322,012	3,906,598	4,491,185
2.04	(1,495,497)	(910,428)	(325,827)	258,773	843,373	1,427,973	2,012,574	2,597,174	3,181,774	3,766,366	4,350,953
2.09	(1,695,283)	(1,050,668)	(466,068)	118,532	703,133	1,287,733	1,872,333	2,456,934	3,041,534	3,626,132	4,210,718
2.14	(1,912,875)	(1,190,909)	(606,308)	(21,708)	562,892	1,147,493	1,732,093	2,316,693	2,901,294	3,485,894	4,070,484
2.19	(2,130,343)	(1,331,146)	(746,546)	(161,946)	422,655	1,007,255	1,591,855	2,176,455	2,761,056	3,345,656	3,930,252
2.24	(2,347,812)	(1,471,984)	(886,784)	(302,184)	282,417	867,017	1,451,617	2,036,218	2,620,818	3,205,418	3,790,019

As shown in Figure 26, the breakeven price for corn is about $3.40 per bushel for a 40 million gallon per year plant in Hankinson. The breakeven price for corn is $3.20 per bushel for the 30 MMGPY plant in Valley City and the breakeven price for barley for the 10 MMGPY plant in Minot is about $2.55 per bushel. The higher the breakeven price for corn (or barley), the better.

Figure 26 – Effect of Feedstock Price on Average Annual Income

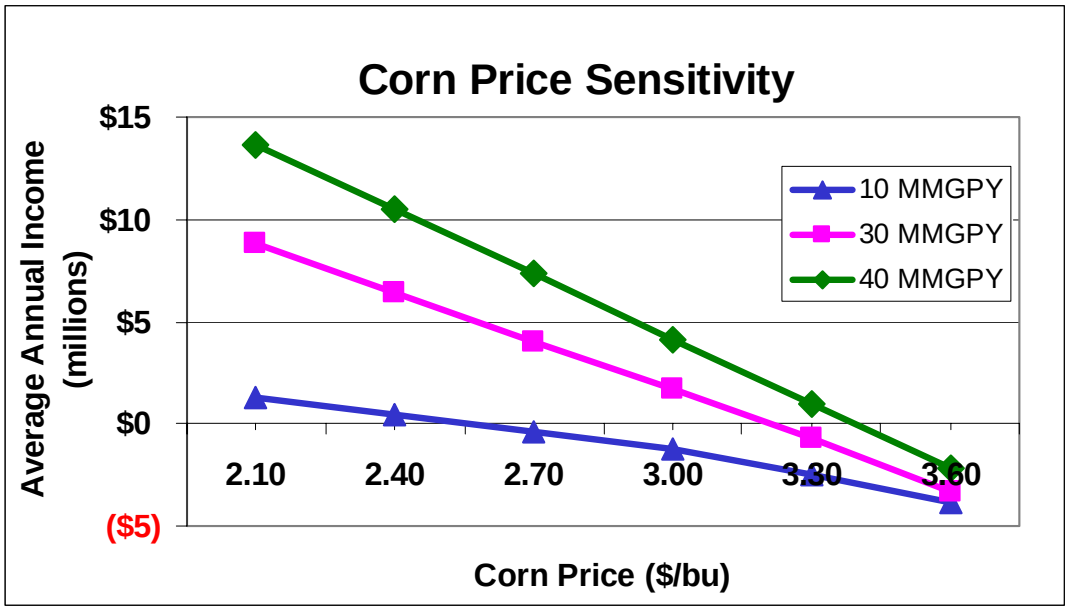
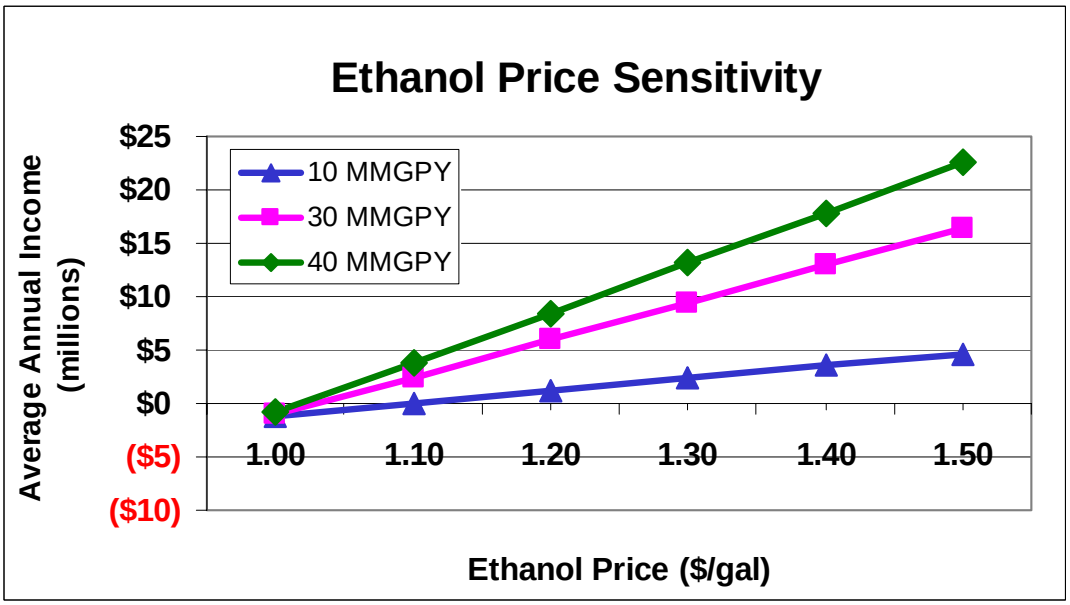


Figure 27 – Effect of Ethanol Selling Price on Average Annual Income



As shown in Figure 27, the breakeven price for ethanol is about $1.02 per gallon for a 40 million gallon per year plant in Hankinson. The breakeven price for the 30 MMGPY plant in Valley City is $1.03 per gallon and the breakeven price for the 10 MMGPY plant in Minot is about $1.10 per gallon. The lower the breakeven price for ethanol, the better.

Sensitivity analyses were also run for three other project-critical parameters: the cost of lignite, the capital cost of the lignite-fired cogeneration plant, and the selling price of DDGS. These results are shown in Figure 28 through Figure 31 below.

Figure 28 shows the sensitivity of the projects to lignite prices ranging from $0 to $20 per ton (excluding transportation costs). The impact on the average annual income is relatively small.

Figure 29 shows the sensitivity of the projects to lignite transportation costs ranging from $0 to $20 per ton. The impact on the average annual income is relatively small.

Figure 30 shows the sensitivity of the projects to the capital cost of the cogeneration plant capital cost. The average annual income is relatively insensitive to the capital cost of the cogeneration facility (compared to the impact of changing ethanol or grain prices).

Figure 31 shows similar data for the selling price of DDGS. The results show that for the 30 and 40 MMGPY plants, the breakeven selling price of DDGS is well below $60 per ton. The breakeven price for the 10 MMGPY plant is about $55 per ton.

Figure 28 – Sensitivity Analysis for Lignite Price

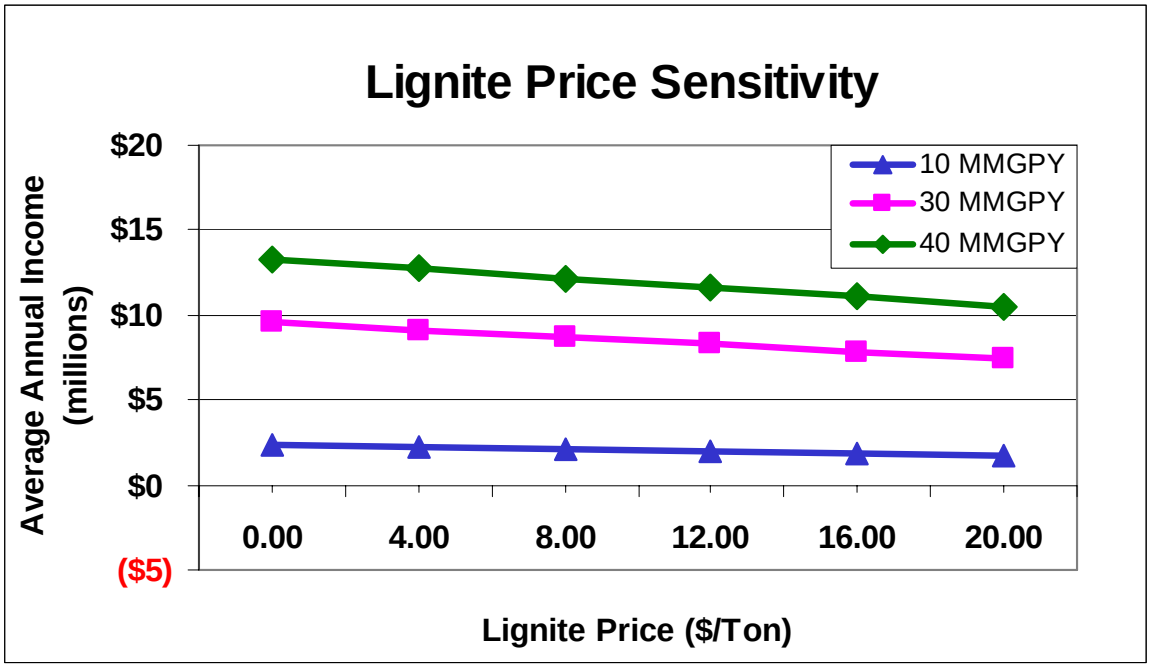


Figure 29 – Sensitivity Analysis for Lignite Transportation Costs

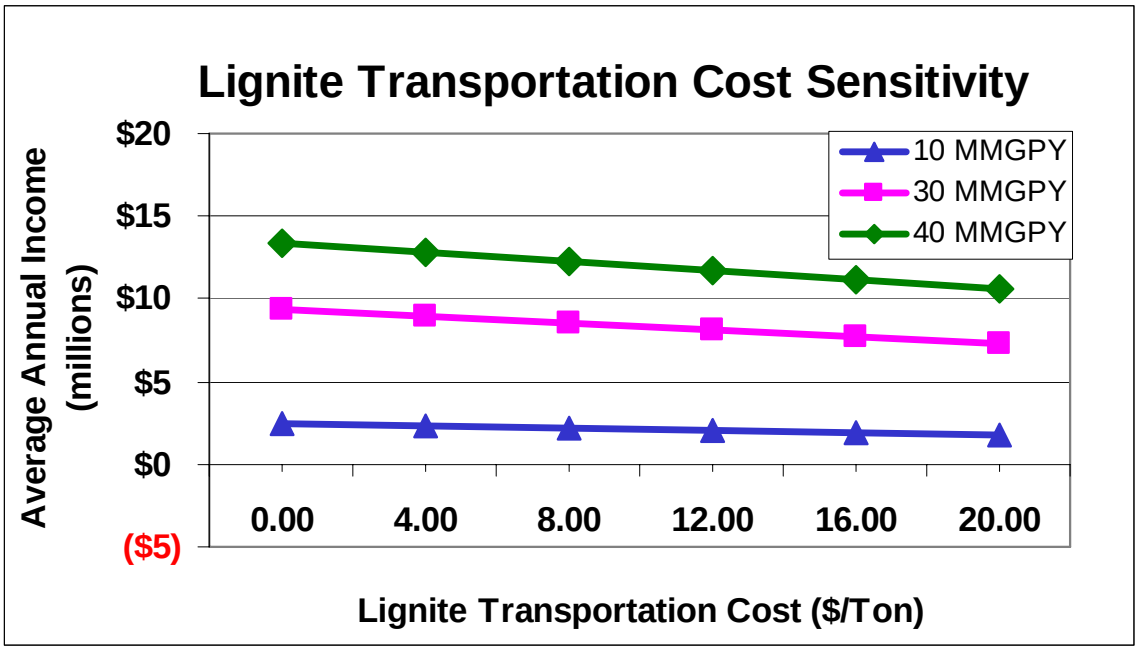


Figure 30 – Sensitivity Analysis for Cogeneration Plant Capital Cost

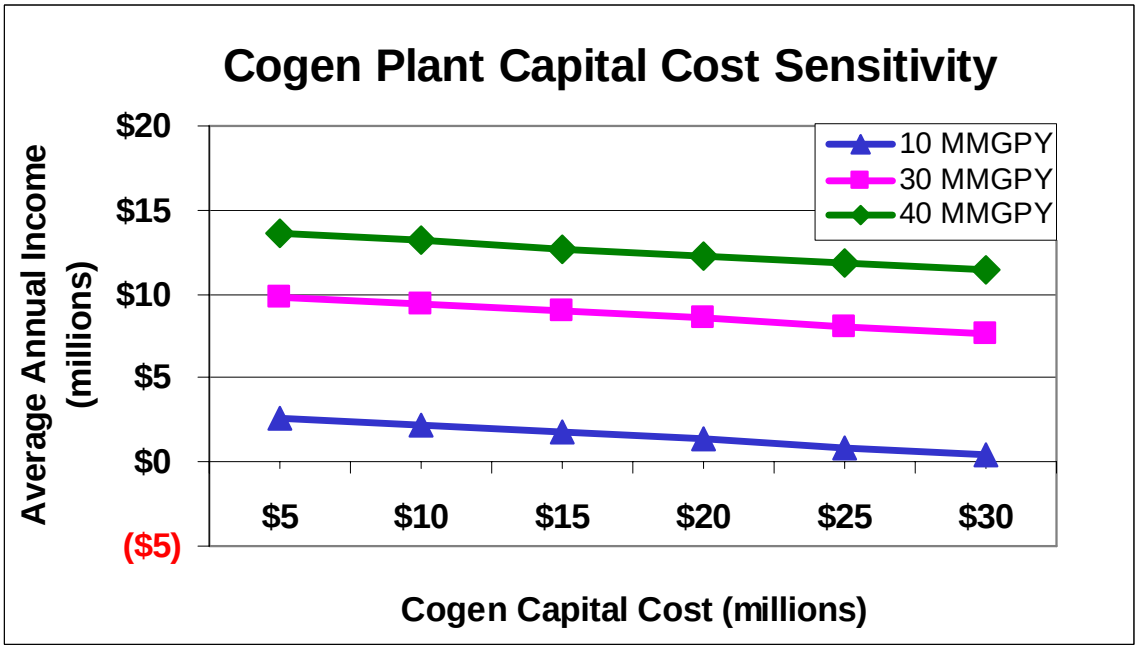
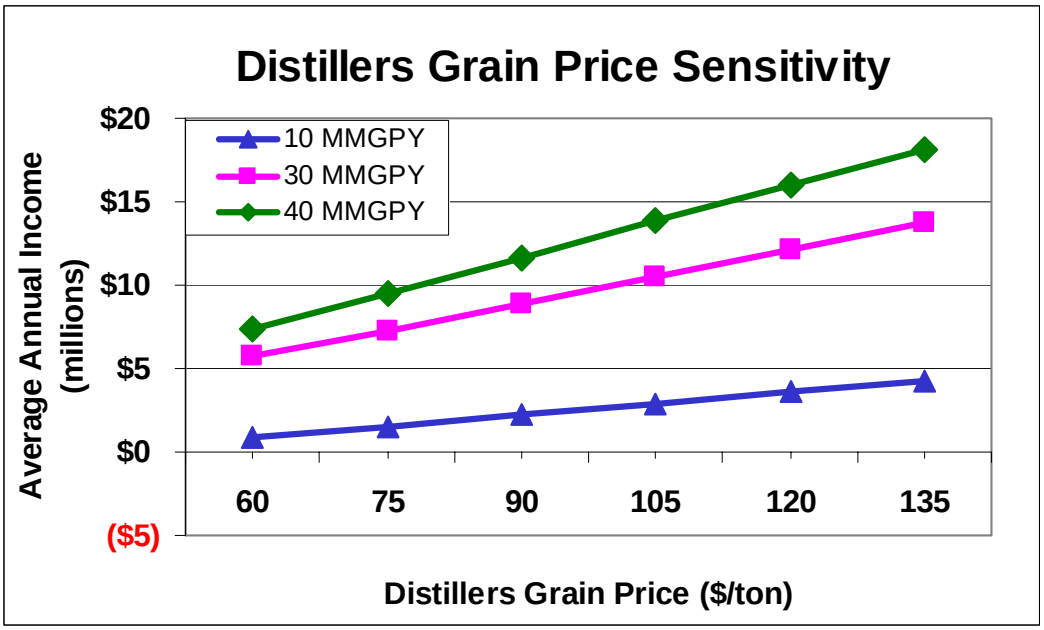


Figure 31 – Sensitivity Analysis for DDGS Selling Price



Comparison to Natural Gas-Fired Ethanol Plants

Most ethanol plants use natural gas to produce steam and to dry the distillers grain. Electricity is usually purchased from the local utility company. The financial forecast for the five sites in this study with natural gas and purchased electricity is shown in the table below. For the comparative analysis, the capital cost for the lignite fired cogeneration facility was replaced with the cost for a thermal oxidizer-waste heat boiler that is now the standard design for natural gas-fired ethanol plants. The number of employees, electricity costs and other minor items were adjusted to a typical ethanol plant scenario.

Table 58 – Modeling Results for Natural Gas-Fired Ethanol Plants

	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
Internal Rate of Return	17.7%	15.8%	12.9%	13.6%	13.6%
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Thermal Oxidizer/Waste Heat Boiler Capital Cost	$3,000,000	$2,500,000	$1,100,000	$3,000,000	$3,000,000
Owner's Costs	$11,086,000	$9,450,000	$5,437,000	$11,188,000	$11,188,000
Total Project Investment	$59,086,000	$46,450,000	$21,537,000	$61,488,000	$61,488,000
Equity (100%)	$59,086,000	$46,450,000	$21,537,000	$61,488,000	$61,488,000
Net Present Value, 8% Discount Rate	$29,150,000	$18,100,000	$4,964,000	$16,765,000	$16,765,000
Net Present Value, 15% Discount Rate	5,943,000	1,411,000	(1,583,000)	(3,206,000)	(3,206,000)

As shown in Table 59, the natural gas-fired production scenario is the more attractive opportunity in terms of the agricultural community and value-added processing.

Table 59 – Comparative Analysis for Natural Gas vs. Lignite-Fired Ethanol Plants

	Site #1 40 MMGPY	Site #2 30 MMGPY	Site #3 10 MMGPY	Site #4 40 MMGPY	Site #5 40 MMGPY
NPV **8% discount rate** – Natural Gas Fired Plant	$29,150,000	$18,100,000	$4,964,000	$16,765,000	$16,765,000
NPV **8% discount rate** – Lignite Fired Plant	$18,663,000	$9,217,000	($8,962,000)	$13,818,000	$11,305,000
NPV **15% discount rate** – Natural Gas Fired Plant	5,943,000	1,411,000	(1,583,000)	(3,206,000)	(3,206,000)
NPV **15% discount rate** – Lignite Fired Plant	(6,768,000)	(9,170,000)	(13,824,000)	(10,671,000)	(12,420,000)

For the comparative analysis with the lignite-fired ethanol production scenarios, the price of natural gas used are those forecast by the DOE Energy Information Agency for the industrial sector by year through 2014 as shown in the following table.

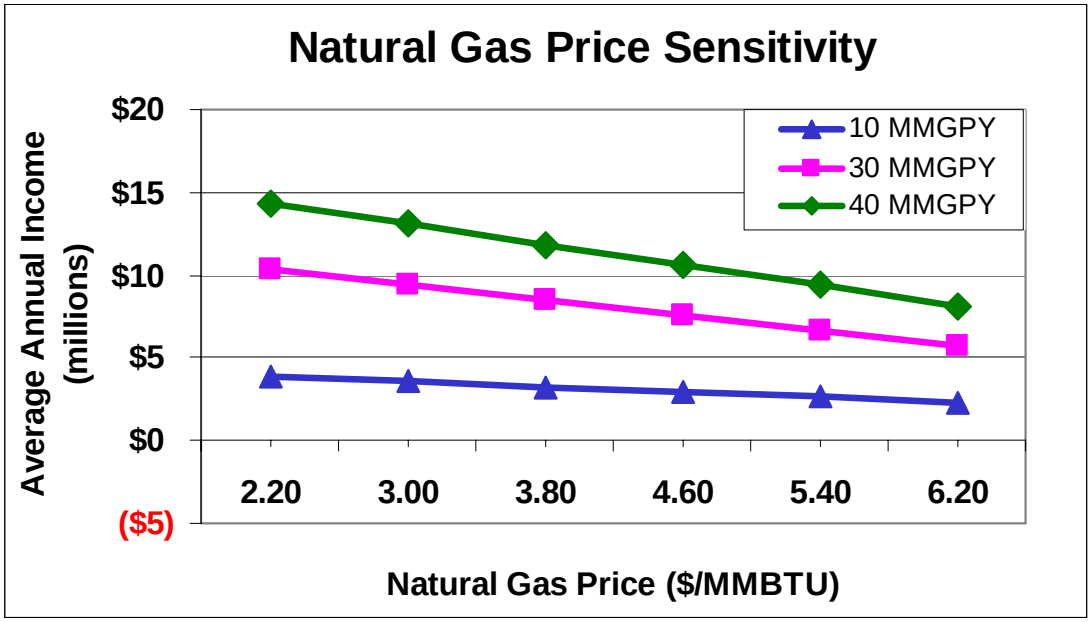
Table 60 – Natural Gas Prices Forecast through 2014

(Source: US DOE EIA)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Average
$/mcf	4.28	4.21	4.25	4.35	4.22	4.16	4.31	4.49	4.67	4.78	4.372

The sensitivity of the natural gas-fired plants to the price of natural gas is shown in Figure 32 below. The sensitivity analysis examined +/-50% of the average price of natural gas as forecast by the EIA. The data show that the project will continue to cash flow with natural gas prices well above $6.00 per MCF.

Figure 32 – Sensitivity of Natural Gas-Fired Plants to the Price of Natural Gas



A further comparison is presented in Table 61 and Table 62. These tables present the pro forma balance sheet results for year 2 for the lignite-fired and natural gas-fired production scenarios respectively.

Table 61 – Year 2 Pro Forma Balance Sheet for Lignite-Fired Ethanol Plants

Proforma Income Statement for Year 2										
Plant Nameplate Design Capacity (gal/year)	**40,000,000**		**30,000,000**		**10,000,000**		**40,000,000**		**40,000,000**	
Net Revenue	**$/Year**	**$/gal**	**$/Year**	**$/gal**	**$/Year**	**$/gal**	**$/Year**	**$/gal**	**$/Year**	**$/gal**
Ethanol	$49,707,252	$1.302	$37,280,439	$1.302	$12,426,813	$1.302	$49,707,252	$1.302	$49,707,252	$1.302
DDGS	$12,111,835	$0.317	$8,565,936	$0.299	$3,652,157	$0.383	$12,908,666	$0.338	$12,908,666	$0.338
DWG	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Carbon Dioxide	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
State Producer Payment	$400,000	$0.010	$400,000	$0.014	$400,000	$0.042	$400,000	$0.010	$400,000	$0.010
Federal Small Producer Tax Credit	$0	$0.000	$0	$0.000	$1,050,000	$0.110	$0	$0.000	$0	$0.000
USDA CCC Bioenergy Program	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Total Revenue	$62,219,087	$1.630	$46,246,375	$1.615	$17,528,970	$1.836	$63,015,918	$1.650	$63,015,918	$1.650
Ethanol Plant Production & Operating Expenses										
Feedstocks	$34,577,912	$0.906	$25,254,917	$0.882	$8,790,319	$0.921	$36,852,774	$0.965	$36,852,774	$0.965
Chemicals, Enzymes & Yeast	$2,834,479	$0.074	$2,125,859	$0.074	$911,082	$0.095	$2,834,479	$0.074	$2,834,479	$0.074
Natural Gas	$253,179	$0.007	$189,884	$0.007	$63,295	$0.007	$253,179	$0.007	$253,179	$0.007
Electricity	$130,859	$0.003	$98,144	$0.003	$28,041	$0.003	$130,859	$0.003	$130,859	$0.003
Denaturants	$1,362,570	$0.036	$1,021,928	$0.036	$340,643	$0.036	$1,362,570	$0.036	$1,362,570	$0.036
Makeup Water	$179,866	$0.005	$134,899	$0.005	$46,777	$0.005	$179,866	$0.005	$179,866	$0.005
Effluent Treatment & Disposal	$71,946	$0.002	$53,960	$0.002	$18,711	$0.002	$71,946	$0.002	$71,946	$0.002
Cogen Plant Production & Operating Expenses										
Lignite Fuel (delivered)	$3,006,900	$0.079	$1,960,187	$0.068	$751,140	$0.079	$1,833,053	$0.048	$2,224,335	$0.058
Lime and Limestone	$743,360	$0.019	$557,520	$0.019	$185,840	$0.019	$743,360	$0.019	$743,360	$0.019
Ammonia for SCR	$171,700	$0.004	$127,058	$0.004	$42,925	$0.004	$171,700	$0.004	$171,700	$0.004
Boiler Ash Disposal	$244,800	$0.006	$179,520	$0.006	$59,568	$0.006	$244,800	$0.006	$244,800	$0.006
Direct Labor & Benefits	$1,213,908	$0.032	$1,115,303	$0.039	$872,788	$0.091	$1,213,908	$0.032	$1,213,908	$0.032
Total Production Costs	$44,791,478	$1.173	$32,819,178	$1.146	$12,111,128	$1.269	$45,892,493	$1.202	$46,283,776	$1.212
Gross Profit	$17,427,609	$0.456	$13,427,197	$0.469	$5,417,841	$0.568	$17,123,425	$0.448	$16,732,142	$0.438
Administrative & Operating Expenses										
Maintenance Materials & Services	$1,447,390	$0.038	$1,134,770	$0.040	$552,160	$0.058	$1,494,080	$0.039	$1,494,080	$0.039
Repairs & Maintenance, Wages & Benefits	$978,055	$0.026	$978,055	$0.034	$779,513	$0.082	$978,055	$0.026	$978,055	$0.026
Property Taxes & Insurance	$1,137,947	$0.030	$900,956	$0.031	$447,292	$0.047	$1,172,442	$0.031	$1,172,443	$0.031
Admin. Salaries, Wages & Benefits	$595,628	$0.016	$595,628	$0.021	$378,430	$0.040	$595,628	$0.016	$595,628	$0.016
Office/Lab Supplies & Miscellaneous	$257,499	$0.007	$257,499	$0.009	$257,499	$0.027	$257,499	$0.007	$257,499	$0.007
Total Administrative & Operating Expenses	$4,416,519	$0.116	$3,866,908	$0.135	$2,414,893	$0.253	$4,497,704	$0.118	$4,497,704	$0.118
EBITDA	$13,011,090	$0.341	$9,560,289	$0.334	$3,002,948	$0.315	$12,625,721	$0.331	$12,234,438	$0.320
Less:										
Interest - Operating Line of Credit	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Interest - Senior Debt	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Interest - Subordinated Debt	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Depreciation & Amortization	$4,507,909	$0.118	$3,583,835	$0.125	$1,808,156	$0.189	$4,642,525	$0.122	$4,642,466	$0.122
Current Income Taxes	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Year 2 Annual Net Earnings Before Income Taxes	$8,503,181	$0.223	$5,976,454	$0.209	$1,194,792	$0.125	$7,983,196	$0.209	$7,591,972	$0.199
11-Year Average Annual Pre-Tax Income	**10,545,000**	**$0.276**	**7,498,000**	**$0.262**	**1,681,000**	**$0.176**	**10,041,000**	**$0.263**	**9,669,000**	**$0.253**
Internal Rate of Return (IRR)	**12.7%**		**11.0%**		**1.3%**		**11.4%**		**10.8%**	
Net Present Value, 8% discount rate	**18,663,000**		**9,217,000**		**(8,962,000)**		**13,818,000**		**11,305,000**	
Net Present Value, 15% discount rate	**(6,768,000)**		**(9,170,000)**		**(13,824,000)**		**(10,671,000)**		**(12,420,000)**	

Note - $/gal figures are based on annual anhydrous ethanol production

Table 62 – Year 2 Pro Forma Balance Sheet for Natural Gas-Fired Ethanol Plants

Proforma Income Statement for Year 2										
Plant Nameplate Design Capacity (gal/year)	**40,000,000**		**30,000,000**		**10,000,000**		**40,000,000**		**40,000,000**	
Net Revenue	**$/Year**	**$/gal**	**$/Year**	**$/gal**	**$/Year**	**$/gal**	**$/Year**	**$/gal**	**$/Year**	**$/gal**
Ethanol	$49,707,252	$1.302	$37,280,439	$1.302	$12,426,813	$1.302	$49,707,252	$1.302	$49,707,252	$1.302
DDGS	$12,111,835	$0.317	$8,565,936	$0.299	$3,652,157	$0.383	$12,908,666	$0.338	$12,908,666	$0.338
DWG	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Carbon Dioxide	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
State Producer Payment	$400,000	$0.010	$400,000	$0.014	$400,000	$0.042	$400,000	$0.010	$400,000	$0.010
Federal Small Producer Tax Credit	$0	$0.000	$0	$0.000	$1,050,000	$0.110	$0	$0.000	$0	$0.000
USDA CCC Bioenergy Program	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Total Revenue	$62,219,087	$1.630	$46,246,375	$1.615	$17,528,970	$1.836	$63,015,918	$1.650	$63,015,918	$1.650
Ethanol Plant Production & Operating Expenses										
Feedstocks	$34,577,912	$0.906	$25,254,917	$0.882	$8,790,319	$0.921	$36,852,774	$0.965	$36,852,774	$0.965
Chemicals, Enzymes & Yeast	$2,834,479	$0.074	$2,125,859	$0.074	$911,082	$0.095	$2,834,479	$0.074	$2,834,479	$0.074
Natural Gas	$6,413,860	$0.168	$4,810,395	$0.168	$1,603,465	$0.168	$6,413,860	$0.168	$6,413,860	$0.168
Electricity	$1,472,165	$0.039	$1,104,124	$0.039	$315,464	$0.033	$1,472,165	$0.039	$1,472,165	$0.039
Denaturants	$1,362,570	$0.036	$1,021,928	$0.036	$340,643	$0.036	$1,362,570	$0.036	$1,362,570	$0.036
Makeup Water	$179,866	$0.005	$134,899	$0.005	$46,777	$0.005	$179,866	$0.005	$179,866	$0.005
Effluent Treatment & Disposal	$71,946	$0.002	$53,960	$0.002	$18,711	$0.002	$71,946	$0.002	$71,946	$0.002
Cogen Plant Production & Operating Expenses										
Lignite Fuel (delivered)	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Lime and Limestone	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Ammonia for SCR	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Boiler Ash Disposal	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Direct Labor & Benefits	$1,069,998	$0.028	$971,393	$0.034	$603,623	$0.063	$1,069,998	$0.028	$1,069,998	$0.028
Total Production Costs	$47,982,796	$1.257	$35,477,474	$1.239	$12,630,084	$1.323	$50,257,658	$1.316	$50,257,658	$1.316
Gross Profit	$14,236,291	$0.373	$10,768,901	$0.376	$4,898,886	$0.513	$12,758,260	$0.334	$12,758,260	$0.334
Administrative & Operating Expenses										
Maintenance Materials & Services	$974,400	$0.026	$751,100	$0.026	$326,830	$0.034	$1,021,090	$0.027	$1,021,090	$0.027
Repairs & Maintenance, Wages & Benefits	$395,753	$0.010	$395,753	$0.014	$206,538	$0.022	$395,753	$0.010	$395,753	$0.010
Property Taxes & Insurance	$783,948	$0.021	$612,949	$0.021	$277,796	$0.029	$818,445	$0.021	$818,445	$0.021
Admin. Salaries, Wages & Benefits	$563,648	$0.015	$563,648	$0.020	$378,430	$0.040	$563,648	$0.015	$563,648	$0.015
Office/Lab Supplies & Miscellaneous	$257,499	$0.007	$257,499	$0.009	$257,499	$0.027	$257,499	$0.007	$257,499	$0.007
Total Administrative & Operating Expenses	$2,975,247	$0.078	$2,580,948	$0.090	$1,447,093	$0.152	$3,056,434	$0.080	$3,056,434	$0.080
EBITDA	$11,261,044	$0.295	$8,187,953	$0.286	$3,451,793	$0.362	$9,701,826	$0.254	$9,701,826	$0.254
Less:										
Interest - Operating Line of Credit	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Interest - Senior Debt	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Interest - Subordinated Debt	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Depreciation & Amortization	$3,123,020	$0.082	$2,458,843	$0.086	$1,141,798	$0.120	$3,257,462	$0.085	$3,257,462	$0.085
Current Income Taxes	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000	$0	$0.000
Year 2 Annual Net Earnings Before Income Taxes	$8,138,024	$0.213	$5,729,110	$0.200	$2,309,995	$0.242	$6,444,364	$0.169	$6,444,364	$0.169
11-Year Average Annual Pre-Tax Income	**9,830,000**	**$0.257**	**6,979,000**	**$0.244**	**2,641,000**	**$0.277**	**8,212,000**	**$0.215**	**8,212,000**	**$0.215**
Internal Rate of Return (IRR)	**17.7%**		**15.8%**		**12.9%**		**13.6%**		**13.6%**	
Net Present Value, 8% discount rate	**29,150,000**		**18,100,000**		**4,964,000**		**16,765,000**		**16,765,000**	
Net Present Value, 15% discount rate	**5,943,000**		**1,411,000**		**(1,583,000)**		**(3,206,000)**		**(3,206,000)**	

Note - $/gal figures are based on annual anhydrous ethanol production

Comments on Profitability and Economic Forecasts

The word profitability is a general term for the measure of the amount of profit that can be obtained from a given situation. Total profit alone cannot be used as the deciding factor in determining if an investment should be made, however. Many factors must be considered when deciding if a return is acceptable, and it is not possible to give one figure that will apply for all investment situations.

There are many methods for measuring or estimating profitability: return on investment, internal rate of return, net present value and payback period are just a few. In this report we have used the Internal Rate of Return (IRR) and the Net Present Value (NPV) with discount rates of 8% and 15% as the primary measures of the estimated project profitability.

When dealing with common industrial operations, profits cannot be predicted with absolute accuracy. Risk factors must be given careful consideration and the degree of uncertainty in estimated returns on investments plays an important role in determining what returns are acceptable (higher risk should equal higher returns). Because of the inherent risk, a 15% return on equity before income taxes is usually the minimum acceptable return for any type of business proposition, even if the economics appear to be completely sound and reliable. Some companies require a 25% pretax return before they will consider investing capital in a project. A 20% rate of return is considered the minimal acceptable return or "hurdle rate" for an ethanol project by many investors.

The economic forecasts and projected profitability presented in the remainder of this report are estimates only. When dealing with commodities such as grain and gasoline (the two main drivers in the project's profitability), one can only make an educated guess as to what the future may hold. Additional project risk factors are discussed in the Summary and Recommendations section of this report. That said, BBI has used its experience and expertise to provide our best estimate as to the project's future profitability. The sensitivity analyses provided in this report show the possible wide swings in the project's profitability when the economic forecast model input assumptions change. The impact of changes in grain, gasoline, energy costs and other project variables should be well understood by the project sponsor and investors.

Challenges

There are a number of challenges that should be addressed before a decision to move forward is made. Project developers should also focus their efforts on the issues that have the greatest impact on the proposed project's profitability:

- A realistic assessment of the project's ability to attract the required equity must be made
- Structuring the project ownership so that the Federal Small Producer Tax Credit can be claimed (if the current ethanol production limit is increased to 60 MMGPY)

- Maximizing revenue from ethanol and DDGS (through marketing relationships, selling wet distillers grain and minimizing transportation costs)
- Reducing delivered grain price through supply contracts and negotiated rail rates
- Obtaining favorable long-term lignite contracts for purchasing lignite and lignite transportation

Risk Factors

The project and its investors will be subject to a number of risks to start-up ventures in general and to the major risks involved in the development and operation of the project and ethanol production facilities specifically. The failure to prevent or mitigate any of the following risks could jeopardize the project and/or the financial returns projected.

New Venture

The project sponsor may be a start-up company created specifically for the purpose of developing and operating the project. The sponsor likely will not have, nor contemplate having, significant financial resources other than its ownership of the project.

Completion Risk

The financial success of the project is dependent upon the timely completion of the plant construction within budget. This risk should be mitigated by extensive preliminary engineering and equipment selection activities prior to the start of construction together with the financial resources and outstanding record of success of the contractor, backed by payment and performance bonding. It is recommended that each of the firms involved in the project should have a proven record of success in similar undertakings.

Performance Risk

A major success factor of the project is dependent upon the process design parameters regarding feedstock throughput and product yields and quality being matched or exceeded during commercial operations. A record of successes in this area is the principal reason for choosing a specific process engineer.

Political Risk

The fuel ethanol industry is dependent upon tax policies and environmental regulations which favor the use of the product in motor fuel blends in North America. The repeal or substantial modification of the U.S. Federal Excise Tax exemption on ethanol blends or, to a much lesser extent, other federal or state tax programs encouraging the use of ethanol could have a detrimental effect on the industry and the project. Changes in gasoline specification or the development of other cost-effective additives competitive with ethanol could adversely affect the product. BBI believes that the ethanol industry and the product will continue to enjoy favorable support from national politicians and environmental regulators.

Market Risk

The major risk associated with the ongoing operation of an ethanol plant relates to the fact that grain feedstocks comprising the major portion of operating expenses do not have any price relationship to fuel ethanol. In a conventional corn dry milling plant serving only fuel grade markets, falling gasoline prices coupled with a rise in corn cost can result in severe constraints on cash flow which could jeopardize the project and/or the projected financial returns.

Technological Risk

There is the risk that alternative products to ethanol could be developed for use as a fuel additive or in industrial applications or that improved ethanol production processes could be introduced. BBI believes that the prospect of an occurrence of either of these developments is unlikely. Ethanol does compete with several other products in the gasoline marketplace, all of which are based on the use of hydrocarbons as raw materials. Industrial demand is often based on the product's unique properties in specific applications where there is no currently viable alternative. There is no substitute in the manufacture of certain beverages. Most process improvements in the near term are expected to be in the areas of development of new feedstocks and improved yields for existing major feedstocks, any of which probably could be introduced into the project without considerable cost to the owner while maintaining the project's competitive advantages.

Risk Summary

Finally, the risks for this project are no worse than those any other plant, planned or operating, faces today. With the new energy policy being developed, the shortage of refining capacity, and the need for ethanol as an oxygenate, the demand for ethanol will remain well into the future. The risk of utility costs rising can be managed through good energy management and forward contracting programs particularly with natural gas.

X. LABOR REQUIREMENTS AND ECONOMIC IMPACTS

Labor Requirements

Labor requirements for lignite powered ethanol plants and natural gas powered ethanol plants for sites #1 - #5 are shown in the tables below. Today's ethanol plants are highly automated and the number of operators required is quite modest. The labor shown includes all operations, maintenance and management personnel. A modern 40 mmgy plant with a natural gas fired boiler (or thermal oxidizer with a waste heat recovery boiler) requires approximately 36 employees – this number may vary slightly with the plant design. Using a lignite fired boiler would require approximately 15 additional operators for coal and ash handing and increased maintenance. Again this number may vary slightly depending upon the degree of automation of the boiler and auxiliary support systems.

Table 63 – Employees Required for Natural Gas-Fired Ethanol Plants

Employees	Site #1	Site #2	Site #3	Site #4	Site #5
Administration/Management					
General Manager	1	1	1	1	1
Plant Manager	1	1	1	1	1
Quality Control Manager	1	1	0	1	1
Controller	1	1	1	1	1
Commodity Manager	1	1	0	1	1
Administrative Assistant	2	2	1	2	2
Production Labor					
Microbiologist	1	1	1	1	1
Lab Technician	1	1	1	1	1
Shift Team Leader	4	4	4	4	4
Shift Operator	12	10	4	12	12
Yard/Commodities Labor	4	4	2	4	4
Maintenance					
Maintenance Manager	1	1	0	1	1
Boiler Operator	1	1	0	1	1
Maintenance Worker	2	2	1	2	2
Welder	1	1	1	1	1
Electrician	1	1	1	1	1
Instrument Technician	1	1	1	1	1
Total Number of Employees	36	34	20	36	36

Table 64 – Employees Required for Lignite-Fired Ethanol Plants

Employees	Site #1	Site #2	Site #3	Site #4	Site #5
Administration/Management					
General Manager	1	1	1	1	1
Plant Manager	1	1	1	1	1
Quality Control Manager	1	1	0	1	1
Controller	1	1	1	1	1
Commodity Manager	1	1	0	1	1
Administrative Assistant	3	3	1	3	3
Production Labor					
Microbiologist	1	1	1	1	1
Lab Technician	1	1	1	1	1
Shift Team Leader	4	4	4	4	4
Shift Operator	12	10	8	12	12
Yard/Commodities Labor	8	8	4	8	8
Maintenance					
Maintenance Manager	1	1	1	1	1
Boiler Operator	6	6	6	6	6
Maintenance Worker	5	5	2	5	5
Welder	1	1	1	1	1
Electrician	2	2	2	2	2
Instrument Technician	2	2	1	2	2
Total Number of Employees	51	49	35	51	51

The lignite powered ethanol plants will require about 15 more employees than the natural gas fired plants as shown in the table below.

Table 65 – Lignite and Natural Gas Powered Ethanol Plant Employee Summary

	Site #1	Site #2	Site #3	Site #4	Site #5
Natural Gas Powered – Total Number of Employees	36	34	20	36	36
Lignite Powered – Total Number of Employees	51	49	35	51	51
Additional Employees Required for Lignite Powered Ethanol Plants	15	15	15	15	15

Tax Impacts and Economic Impacts

Construction and operation of ethanol plants in North Dakota will create significant economic activity in local communities where the production facilities are located. The ethanol plant construction and operation will involve expenditures, income, employment and payment of taxes. The expenditures of a business become the income of other businesses or individuals, which in turn is re-spent in the economy to provide income for

others. Thus the initial economic activity has a multiplier effect that ripples through the economy. Economic impact analysis is an analytical method that provides a measure of the economic effects of an activity within a specified region.

In this section BBI has estimated the economic impacts of ethanol production in North Dakota for the five sites using both lignite and natural gas to power the ethanol plants. The final demand impact, household earnings impact and job impacts were estimated by applying the appropriate demand multipliers calculated by the U.S. Bureau of Economic Analysis for output, earnings, and employment to the estimates of new capital spending and annual operating expenditures associated with the proposed ethanol plants. The resulting economic impacts are reported as estimated changes in the economic base (final demand), income, jobs and taxes resulting from ethanol production in North Dakota.

Methodology

Multipliers for the grain milling industry were used to estimate the impact from annual operations since the main input for ethanol production is grain while the most appropriate multipliers for new plant construction are those for the construction sector.

The multipliers used in this analysis are the two-digit industry RIMS II multipliers reported in "Ethanol and the Local Community," J. M. Urbanchuk, AUS Consultants and J. Kapell, SJH & Company, June 20, 2002. The multipliers utilized by Urbanchuk and Kapell were estimated by the Bureau of Economic Analysis, U.S. Department of Commerce. The final demand multipliers for the grain milling and construction sectors are 1.9623 and 2.4266, respectively; the household income multipliers are 0.349 and 0.7878. The employment multipliers are 10.5623 for grain milling and 24.607 for new construction.

The method used in the study provides specific measures of economic impact in the following categories.

Total Expenditures – Total expenditures are the sum of all direct spending made by the proposed ethanol facilities in North Dakota. This category includes all direct costs associated with two distinct phases of activity and spending: construction and operation. Construction is a short-term, one-time activity associated with establishing an ethanol production facility. The operations phase is a longer term, ongoing activity associated with ethanol production.

Total expenditures during operations include salaries and wages paid to direct employees, compensation paid to managers, purchases of equipment, feedstocks and process raw materials, and all contracted services. Total operating expenditures are the sum of the "Total Production Costs" and "Total Administrative & Operating Expenses" shown in Table 61 – Year 2 Pro Forma Balance Sheet for Lignite-Fired Ethanol Plants and Table 62 – Year 2 Pro Forma Balance Sheet for Natural Gas-Fired Ethanol Plants.

Direct Income – Direct income is the sum of money paid directly by the facility or project to its direct employees in North Dakota. Direct income also includes profits or dividends paid to owners in the state. It does not include payments to contractors.

Direct Employment – Direct employment is the number of persons employed directly by the proposed plants in the state, including management. This information is presented in the previous section and is estimated from industry sources.

Indirect Income – Indirect income, as used in this analysis, is the sum of the indirect and induced income. It is composed of the sum of the expenditures made by the companies that supply the planned facility (indirect income), plus the expenditures made by employees of the facility and the expenditures made by employees of the suppliers (induced income). These expenditures typically include such items as spare parts, supplies, fuel, utilities, trucking, financial services, and the retail or other personal expenditures of employees. Estimates of indirect income are obtained by taking the plant's expenditure for supplies, equipment, and services and applying multipliers to estimate the amount of indirect and induced income from each class of expenditure.

Indirect Employment – Indirect employment is the number of persons employed as a result of the indirect income generated by the facility in the area of interest. The indirect employment is estimated by applying the appropriate indirect employment multiplier to the total amount of indirect income associated with the plant.

State Tax Revenue – The amount of corporate tax revenue paid to the state by an ethanol plant will be dependent on the profitability of the plant as well as its parent company. Since it is impossible to predict the future profitability and financial performance of a given facility, or the actual amount of facility-specific tax payments, in the present study taxes paid to the state are assumed to be a percentage of net income for the facility, and all directly and indirectly related activities are the same as the state average.

Tax rates used in the economic impact analysis are 5.9% for individual or personal income taxes in North Dakota (based on an average household income of $50,000 per ethanol plant employee (source: *State and Local Taxes An Overview and Comparative Guide 2002* North Dakota State Office of Tax Commissioner, November 2002, p-61). The tax rate for corporations in North Dakota with taxable income greater than $50,000 is 10.5% (source Tax Foundation, Washington, DC; http://taxfoundation.org/home.html). If the ethanol business is organized as a Limited Liability Company (LLC), it would have no tax liability – tax liability would pass through to the LLC members.

Incentives provided by the state are included in the analysis of state tax revenues. Incentive payments, producer credits, tax exemptions and credits, and subsidies are factored into the analysis, to estimate the impact of the proposed facilities on state tax

revenues. In the case where incentive payments and tax credits are offered by the state, the return on incentives to the state can also be calculated.

Analysis Inputs

The inputs required for the economic analysis are the ethanol project direct impacts divided into construction phase impacts and operations phase impacts. This distinction is important because the construction phase impacts are a one-time event while the operations phase impacts are ongoing impacts. Construction phase impacts for the ethanol plants are assumed to occur over a 14-month construction and startup period, while the operations phase will normally last many years and are characterized by expressing the impacts on an annual basis. This distinction is important because the construction and operations impacts are usually very different in character as well as magnitude. Construction may bring temporary workers into the area that take up temporary residences near the site and therefore have a different impact than the permanent workers and contractors of the operations phase.

The following tables list the analysis inputs for the five hypothetical plants based on the estimated cost to construct and operate the proposed ethanol plants at the North Dakota sites. The construction and operating costs in the table are discussed in the cost estimate section of this report.

Operating expenditures include all payments made directly by the ethanol plant owner. These payments include all production and administrative costs projected for the first full year of commercial operation for the project.

Table 66 – Economic Impact Analysis Inputs for North Dakota Ethanol Plants

Construction Phase Impacts	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Lignite Powered Ethanol Plant Capital Cost (millions)	$83.1	$66.0	$33.1	$85.4	$85.4
Natural Gas Powered Ethanol Plant Capital Cost (millions)	$59.1	$46.5	$21.5	$61.5	$61.5

Operations Phase Impacts	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Lignite Powered Ethanol Plant					
Operating Expenditures (millions)	$49.2	$36.7	$14.5	$50.4	$50.8
Ethanol Plant Direct Jobs	51	49	35	51	51
Nat. Gas Powered Ethanol Plant					
Operating Expenditures (millions)	$51.0	$38.1	$14.1	$53.3	$53.3
Ethanol Plant Direct Jobs	36	34	20	36	36

Economic Impacts of Lignite Powered Ethanol Plants

The results of the economic impact analysis for the lignite powered ethanol plants are presented in Table 67 below. There are three primary measures of economic impact presented, which should be considered separately. These are income, employment and taxes. Income and employment include both indirect and induced impacts. Taxes are estimated at the state level based on tax rates in North Dakota. The results are separated into the construction phase and operations phase impacts. Construction phase and operations phase impacts should be considered separately and should not be added together. Although the impacts are expressed in the same manner, they are not directly comparable.

The construction spending associated with building the five lignite powered ethanol plants in North Dakota will add approximately $856 million to the final demand in the local economy and generate $278 million in new household income and provide for 8,685 direct and indirect jobs during construction of the five ethanol plants presented in this report.

During the operations phase, the five lignite powered ethanol plants will create 2,366 new jobs and add approximately $396 million to the final demand in the local economy. New household income will be approximately $70 million annually. Annual state tax revenue on new household income is estimated to be $4.1 million.

Table 67 – Economic Impacts of Lignite-Fired Ethanol Production in North Dakota

Construction Phase Impacts	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Ethanol Plant Capital Cost (millions)	$83.1	$66.0	$33.1	$85.4	$85.4
Final Demand Impact (millions)	$201.6	$160.1	$80.3	$207.2	$207.3
Household Earnings Impact (millions)	$65.4	$52.0	$26.1	$67.3	$67.3
Employment Impacts (indirect jobs)	2,044	1,624	814	2,101	2,102
Operations Phase Impacts	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Operating Expenditures (millions)	$49.2	$36.7	$14.5	$50.4	$50.8
Final Demand Impact (millions)	$96.6	$72.0	$28.5	$98.9	$99.6
Household Earnings Impact (millions)	$17.2	$12.8	$5.1	$17.6	$17.7
Employment Impacts (direct jobs)	51	49	35	51	51
Employment Impacts (indirect jobs)	520	387	153	532	536
Total Jobs	571	436	188	583	587
Estimated State Income Tax on Household Earnings (millions)	$1.0	$0.8	$0.3	$1.0	$1.0

The operation of ethanol facilities in North Dakota will potentially generate corporate as well as personal income tax revenues for both the federal and state governments. The projected tax revenues are shown in Table 68. The tax revenues shown are estimates only

and will depend upon the profitability and ownership structure of each ethanol plant. The "Average Ethanol Plant Pre-Tax Income" shown in the table is from the financial analysis of the five plants presented earlier in this report.

In April 2003, North Dakota's Governor signed into law an Ethanol Production Incentive bill (Senate Bill 2222). The legislation implements the first program in the nation to create a market-based support system for the growing ethanol industry. The ethanol incentive operates on a counter cyclical feature that is market-based. It is not a fixed payment, but is provided to a facility when the price of ethanol drops or the price of corn increases to levels that make ethanol less profitable. Incentives are based on a combination of a $1.80/bushel price for corn and a $1.30/gallon rack price for ethanol (price at the terminal).

We have assumed that each plant will qualify for annual state producer payments of $400,000 each. These payments are dependent upon funding from the state and corn and ethanol pricing and are, therefore, are subject to change. The total annual state producer payments for the five plants of $2.0 million are more than offset by $8.3 million in increased State tax revenue.

Table 68 – Estimated Tax Impacts of Lignite-Fired Ethanol Production in ND

Tax Impacts (millions)	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Personal Earnings Impact (note 1)	$17.2	$12.8	$5.1	$17.6	$17.7
North Dakota Income Tax on Personal Earnings (note 2)	$1.0	$0.8	$0.3	$1.0	$1.0
Average Ethanol Plant Pre-Tax Income (note 3)	$10.5	$7.5	$1.7	$10.0	$9.7
State Corporate Income Tax Revenue (note 4)	$1.1	$0.8	$0.2	$1.1	$1.0
Total Tax Revenue (millions)	$2.1	$1.5	$0.5	$2.1	$2.1
State Producer Payment (note 5)	$0.4	$0.4	$0.4	$0.4	$0.4
Annual Return to State (millions)	$1.7	$1.1	$0.1	$1.7	$1.7

Notes:

1. The Personal Earnings Impact includes direct and indirect personal earnings resulting from the operation of five lignite powered ethanol plants in North Dakota.
2. North Dakota personal income tax rate of 5.9% used to estimate taxes.
3. See the Financial Analysis section of the report for the Average Ethanol Plant Pre-Tax Income.
4. A state corporate income tax rate of 10.5% has been assumed.
5. State Producer Payments are dependant upon corn and ethanol pricing in North Dakota and funding from the state.

Economic Impacts of Natural Gas Powered Ethanol Plants

The results of the economic impact analysis for the natural gas powered ethanol plants are presented in Table 69 below. The results are separated into the construction phase and operations phase impacts. Construction phase and operations phase impacts should be considered separately and should not be added together. Although the impacts are expressed in the same manner, they are not directly comparable.

The construction spending associated with building the five natural gas powered ethanol plants in North Dakota will add approximately $607 million to the final demand in the local economy and generate $197 million in new household income and provide for 6,153 direct and indirect jobs during construction of the five ethanol plants presented in this report.

During the operations phase, the five natural gas powered ethanol plants will create 2,377 new jobs and add approximately $412 million to the final demand in the local economy. New household income will be approximately $73 million annually. Annual state tax revenue on new household income is estimated to be $4.3 million.

Table 69 – Economic Impacts of Natural Gas-Fired Ethanol Production in ND

Construction Phase Impacts	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Ethanol Plant Capital Cost (millions)	$59.1	$46.5	$21.5	$61.5	$61.5
Final Demand Impact (millions)	$143.4	$112.7	$52.3	$149.2	$149.2
Household Earnings Impact (millions)	$46.5	$36.6	$17.0	$48.4	$48.4
Employment Impacts (indirect jobs)	1,454	1,143	530	1,513	1,513
Operations Phase Impacts	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Operating Expenditures (millions)	$51.0	$38.1	$14.1	$53.3	$53.3
Final Demand Impact (millions)	$100.0	$74.7	$27.6	$104.6	$104.6
Household Earnings Impact (millions)	$17.8	$13.3	$4.9	$18.6	$18.6
Employment Impacts (direct jobs)	36	34	20	36	36
Employment Impacts (indirect jobs)	538	402	149	563	563
Total Jobs	574	436	169	599	599
Estimated State Income Tax on Household Earnings (millions)	$1.0	$0.8	$0.3	$1.1	$1.1

The operation of natural gas powered ethanol facilities in North Dakota will potentially generate corporate as well as personal income tax revenues for both the federal and state governments. The projected tax revenues are shown in

Table 70.

Table 70 – Estimated Tax Impacts of Natural Gas-Fired Ethanol Production in ND

Tax Impacts (millions)	Site #1	Site #2	Site #3	Site #4	Site #5
Personal Earnings Impact (note 1)	$17.8	$13.3	$4.9	$18.6	$18.6
North Dakota Income Tax on Personal Earnings (note 2)	$1.0	$0.8	$0.3	$1.1	$1.1
Average Ethanol Plant Pre-Tax Income (note 3)	$9.8	$7.0	$2.6	$8.2	$8.2
State Corporate Income Tax Revenue (note 4)	$1.0	$0.7	$0.3	$0.9	$0.9
Total Tax Revenue (millions)	$2.1	$1.5	$0.6	$2.0	$2.0
State Producer Payment (note 5)	$0.4	$0.4	$0.4	$0.4	$0.4
Annual Return to State (millions)	$1.7	$1.1	$0.2	$1.6	$1.6

Notes:

1. The Personal Earnings Impact includes direct and indirect personal earnings resulting from the operation of five natural gas powered ethanol plants in North Dakota.
2. North Dakota personal income tax rate of 5.9% used to estimate taxes.
3. See the Financial Analysis section of the report for the Average Ethanol Plant Pre-Tax Income.
4. A state corporate income tax rate of 10.5% has been assumed.
5. State Producer Payments are dependant upon corn and ethanol pricing in North Dakota and funding from the state.

The tax revenues shown are estimates only and will depend upon the profitability and ownership structure of each ethanol plant. The "Average Ethanol Plant Pre-Tax Income" shown in the table is from the financial analysis of the five plants presented previously in this report.

Summary of Economic and Tax Impacts

The economic and tax impacts of the lignite powered ethanol plants versus natural gas powered plants is shown in the table below. The values shown in the table are the sum of the values for all five sites for the lignite option and the natural gas option.

The construction phase impacts of ethanol plants powered by lignite are significantly greater than the natural gas impacts due to the much greater capital cost for the lignite power facility. The five lignite powered ethanol plants result in 2,532 more jobs during the construction of the plants.

During operations, the natural gas powered ethanol plants create slightly more impacts and jobs due to the higher operating costs associated with natural gas versus lignite fuel. The natural gas option results in 68 more jobs than the lignite option.

State tax impacts are also very similar for the lignite powered ethanol plants when compared to the natural gas powered ethanol plants at the five sites. The lignite option results in slightly higher state taxes at $8.3 million for lignite versus $8.1 million for natural gas.

If the state makes ethanol producer payments to the five ethanol plants totaling $2 million per year as assumed in this analysis, the return to the state will be higher for the lignite option compared to the natural gas option. The Net Present Value (NPV) of the natural gas powered ethanol plants is much higher than the NPV for the lignite power plants because the pre-tax income for both scenarios are about the same, but the capital investment for the natural gas option is significantly less than the lignite option.

Table 71 – Comparison of Impacts for Lignite Power vs. Natural Gas Power for ND Ethanol Plants

Construction Phase Impacts	**Lignite Power**	**Natural Gas Power**
Total Ethanol Plant Capital Costs (millions)	$352.9	$250.0
Final Demand Impact (millions)	$856.4	$606.8
Earnings Impact (millions)	$278.0	$197.0
Employment Impacts (indirect jobs)	8,685	6,153
Operations Phase Impacts	**Lignite Power**	**Natural Gas Power**
Total Operating Expenditures (millions)	$201.6	$209.7
Final Demand Impact (millions)	$395.6	$411.5
Earnings Impact (millions)	$70.4	$73.2
Employment Impacts (direct jobs)	237	162
Employment Impacts (indirect jobs)	2,129	2,215
Total Jobs	2,366	2,377
State Income Tax on Earnings (millions)	$4.2	$4.3
Tax Impacts and State Producer Payments	**Lignite Power**	**Natural Gas Power**
Personal Earnings Impact (millions)	$70.4	$73.2
North Dakota Personal Income Tax on Earnings	$4.2	$4.3
Average Pre-Tax Income (millions)	$39.4	$35.9
North Dakota Corporate Income Tax Revenue	$4.1	$3.8
Total Tax Revenue (millions)	$8.3	$8.1
State Producer Payment (millions)	$2.0	$2.0
Annual Return to State (millions)	$6.3	$6.1

Net Present Value (millions), 8% discount rate	$44.0	$85.7
Net Present Value (millions), 15% discount rate	($52.9)	($0.6)

APPENDIX A

Financial Model Inputs for Lignite-Fired Ethanol Production

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512	28,636,884	9,545,628	38,182,512	38,182,512
Small Producer Tax Credit (Yes or No)	No	No	Yes	No	No
CCC Program Payment in Year 2 (Yes or No)	No	No	No	No	No
Capital Cost per Gallon	1.125	1.15	1.50	1.125	1.125
Project Engineering & Construction Costs					
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Cogeneration System	$26,300,000	$21,400,000	$12,200,000	$26,300,000	$26,300,000
Total Project Construction Cost	$71,300,000	$55,900,000	$27,200,000	$73,600,000	$73,600,000
Owner's Capital Costs					
Administration Building & Furnishing	$300,000	$300,000	$200,000	$300,000	$300,000
Rail Improvements	$950,000	$850,000	$600,000	$950,000	$950,000
Well & Process Water Treatment	$600,000	$500,000	$300,000	$600,000	$600,000
Site Development Costs	$1,500,000	$1,300,000	$700,000	$1,500,000	$1,500,000
Rolling Stock and Tools	$400,000	$400,000	$300,000	$400,000	$400,000
Organizational Costs	$1,100,000	$1,000,000	$600,000	$1,100,000	$1,100,000
Spare Parts	$750,000	$750,000	$500,000	$750,000	$750,000
Startup Costs	$1,000,000	$1,000,000	$800,000	$1,000,000	$1,000,000
Contingency	$1,000,000	$800,000	$500,000	$1,000,000	$1,000,000
% of inventory used for operating line of credit	50%	50%	50%	50%	50%
Land - Total Purchase Price	$100,000	$100,000	$50,000	$100,000	$100,000
Land - Number of Acres	40	40	20	40	40
Land - Cost per Acre	$2,500	$2,500	$2,500	$2,500	$2,500
Capitalized Fees & Interest	$1,900,000	$1,500,000	$750,000	$1,900,000	$1,900,000
Operating Days per Year	350	350	350	350	350
1st Year Ethanol Yield (anhydrous gal/bu)	2.670	2.670	2.200	2.670	2.670
2nd Year Ethanol Yield (gal/bu)	2.670	2.670	2.200	2.670	2.670
3rd Year Ethanol Yield (gal/bu)	2.670	2.670	2.200	2.670	2.670
Production increase over Nameplate					
1st Year of operations	0%	0%	0%	0%	0%
2nd Year of operations	5%	5%	5%	5%	5%
3rd Year of operations	5%	5%	5%	5%	5%
State Producer Payment (¢/gal)	$0.040	$0.040	$0.040	$0.040	$0.040

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
State Producer Payment - Annual Cap ($)	$400,000	$400,000	$400,000	$400,000	$400,000
State Producer Payment - Number of Years	10	10	10	10	10
Ethanol Selling Price ($/gal)	1.27	1.27	1.27	1.27	1.27
Ethanol Sales Commission (% of sales price)	1.000%	1.000%	1.000%	1.000%	1.000%
Ethanol Transportation Cost ($/gal)	0.097	0.097	0.097	0.097	0.097
Grain Purchase Price ($/bu)	2.28	2.15	1.84	2.43	2.43
Grain Price per dry ton	95.80	90.34	90.20	102.10	102.10
Elevator Handling Fee ($/bu)	0.00	0.07	0.07	0.00	0.00
Grain Test Weight (lb/bu)	56	56	48	56	56
% DWG Sold YEAR 1	0%	0%	0%	0%	0%
% DWG Sold YEAR 2	0%	0%	0%	0%	0%
% DWG Sold YEAR 3 through 10	0%	0%	0%	0%	0%
DDGS Moisture %	10%	10%	10%	10%	10%
DDGS Yield (lb/bu)	18.0	18.0	19.0	18.0	18.0
Max. Annual DDGS Production (ton/year)	128,705	96,529	41,220	128,705	128,705
DDGS % of Grain price - dry basis	105%	105%	105%	105%	105%
DDGS Price ($/ton)	90.53	85.37	85.24	96.49	96.49
DDGS Transportation ($/ton)	0.00	0.00	0.00	0.00	0.00
DDGS Sales Commission (% of Price)	2.00%	2.00%	2.00%	2.00%	2.00%
DDGS Sales Commission ($/ton)	1.81	1.71	1.70	1.93	1.93
DWG Moisture %	65%	65%	65%	65%	65%
DWG Yield (lb/bu)	46.3	46.3	46.3	46.3	46.3
Max. Annual DWG Production (ton/year)	330,956	248,217	100,415	330,956	330,956
DWG % of Grain price - dry basis	110%	110%	110%	110%	110%
DWG Price ($/ton)	36.88	34.78	34.73	39.31	39.31
DWG Transportation ($/ton)	0.00	0.00	0.00	0.00	0.00
DWG Sales Commission (% of Price)	2.00%	2.00%	2.00%	2.00%	2.00%
DWG Sales Commission ($/ton)	0.74	0.70	0.69	0.79	0.79
Backup Natural Gas (BTU/anhydrous gal)	1,500	1,500	1,500	1,500	1,500
Annual Natural Gas Use (MCF/year)	57,274	42,955	14,318	57,274	57,274
Natural Gas Price ($/MMBTU)					
Lignite Use (tons/year)	128,500	96,300	32,100	128,500	128,500
Lignite Cost, at mine ($/ton)	11.00	11.00	11.00	11.00	11.00
Lignite Transportation Cost ($/ton)	12.00	9.00	12.00	3.00	6.00
Lignite Cost, delivered ($/ton)	23.00	20.00	23.00	14.00	17.00

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Lime and Limestone Use (tons/year)	32,000	24,000	8,000	32,000	32,000
Lime and Limestone Cost ($/ton)	23.00	23.00	23.00	23.00	23.00
Ammonia Use for SCR (tons/year)	500	370	125	500	500
Ammonia Cost ($/tons)	340.00	340.00	340.00	340.00	340.00
Boiler Ash Production (ton/year)	30,000	22,000	7,300	30,000	30,000
Boiler Ash Disposal Cost ($/ton)	8.00	8.00	8.00	8.00	8.00
CO2 Produced (lb/gal ethanol)	6.60	6.60	6.60	6.60	6.60
% of CO2 Produced that is Sold	0%	0%	0%	0%	0%
CO2 Sold (lb/gal ethanol)	0.00	0.00	0.00	0.00	0.00
CO2 Price ($/ton)	0.00	0.00	0.00	0.00	0.00
Annual CO2 Sold (tons/year)	0	0	0	0	0
CO2 Sales per Day (tons/day)	0	0	0	0	0
Electricity Use (kWh/gal ethanol)	0.8	0.8	0.8	0.8	0.8
Electricity Price ($/kWh)	0.0040	0.0040	0.0040	0.0040	0.0040
Annual Electricity Use (kWh/year)	30,546,010	22,909,507	7,636,502	30,546,010	30,546,010
Electricity Demand (MW)	3.636	2.727	0.909	3.636	3.636
Makeup Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012
Makeup Water Price ($/1000 gallons)	1.00	1.00	1.00	1.00	1.00
Makeup Water Flow Rate (gpm)	337	252	102	337	337
Daily Makeup Water (gpd)	484,585	363,439	147,027	484,585	484,585
Waste Effluent - % of Makeup Water	20%	20%	20%	20%	20%
Waste Effluent Flow Rate (1000 gal/bu)	0.0024	0.0024	0.0024	0.0024	0.0024
Waste Effluent Price ($/1000 gallons)	2.00	2.00	2.00	2.00	2.00
Waste Effluent Flow Rate (gpm)	67	50	20	67	67
Daily Waste Effluent (gpd)	96,917	72,688	29,405	96,917	96,917
Denaturant Use (% of ethanol sold)	4.76%	4.76%	4.76%	4.76%	4.76%
Denaturant Price ($/gal unleaded gasoline)	0.70	0.70	0.70	0.70	0.70
Chemicals & Enzymes Cost ($/gal ethanol)	0.0700	0.0700	0.0900	0.0700	0.0700
Maintenance Materials & Services (% of Capital Equipment Cost)	2.00%	2.00%	2.00%	2.00%	2.00%
Insurance (% of Depreciated Property, Plant & Equipment)	1.00%	1.00%	1.00%	1.00%	1.00%
Property Tax (% of Depreciated Property, Plant & Equipment)	0.50%	0.50%	0.50%	0.50%	0.50%
Property Tax Abatement (%)	0%	0%	0%	0%	0%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Final Property Tax (% of Depreciated Property, Plant & Equipment)	0.50%	0.50%	0.50%	0.50%	0.50%
Employees	Number	Number	Number	Number	Number
Administration/Management					
General Manager	1	1	1	1	1
Plant Manager	1	1	1	1	1
Quality Control Manager	1	1	0	1	1
Controller	1	1	1	1	1
Commodity Manager	1	1	0	1	1
Administrative Assistant	3	3	1	3	3
Production Labor					
Microbiologist	1	1	1	1	1
Lab Technician	1	1	1	1	1
Shift Team Leader	4	4	4	4	4
Shift Operator	12	10	8	12	12
Yard/Commodities Labor	8	8	4	8	8
Maintenance					
Maintenance Manager	1	1	1	1	1
Boiler Operator	6	6	6	6	6
Maintenance Worker	5	5	2	5	5
Welder	1	1	1	1	1
Electrician	2	2	2	2	2
Instrument Technician	2	2	1	2	2
Total Number of Employees	51	49	35	51	51
Employee Benefits (% of salary)	30%	30%	30%	30%	30%
Other Expenses - During Construction					
Monthly Legal/Accounting Expenses	$10,000	$10,000	$10,000	$10,000	$10,000
Monthly Community/Governmental Relations	$2,000	$2,000	$2,000	$2,000	$2,000
Other Expenses - During Operations					
Monthly Legal/Accounting Expenses	$2,000	$2,000	$2,000	$2,000	$2,000
Monthly Community/Governmental Relations	$1,000	$1,000	$1,000	$1,000	$1,000
Monthly Office/Lab/Misc. Expenses	$8,000	$8,000	$8,000	$8,000	$8,000
Senior Debt					
Principal (% of Total Project Cost)	0.00%	0.00%	0.00%	0.00%	0.00%
Interest Rate (Fixed Interest Rate)	8.000%	8.000%	8.000%	8.000%	8.000%
Lender Fees (% of Principal)	1.0%	1.0%	1.0%	1.0%	1.0%
Placement Fees (% of Principal)	0.0%	0.0%	0.0%	0.0%	0.0%
Amortization Period (in Years)	10	10	10	10	10
Cash Sweep (% of "excess" cash)	0.000%	0.000%	0.000%	0.000%	0.000%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Subordinated Debt					
Principal ($ amount)	0%	0%	0%	0%	0%
Interest Rate	12.000%	12.000%	12.000%	12.000%	12.000%
Lender Fees (% of Principal)	2.0%	2.0%	2.0%	2.0%	2.0%
Placement Fees (% of Principal)	2.0%	2.0%	2.0%	2.0%	2.0%
Amortization Period (in Years)	10	10	10	10	10
Interest Only Payments? (yes/no)	no	no	no	no	no
Grants - Amount	$0	$0	$0	$0	$0
Economic Development Grant	$0	$0	$0	$0	$0
Other Grants	$0	$0	$0	$0	$0
Percent of Grant applied towards reducing Senior Debt	0%	0%	0%	0%	0%
Common Equity Investment					
Amount	Calculated	Calculated	Calculated	Calculated	Calculated
Placement Fees (% of Principal)	1.0%	1.0%	1.0%	1.0%	1.0%
Preferred Shares (% of total equity)	0.000%	0.000%	0.000%	0.000%	0.000%
Common Shares (% of total equity)	100.000%	100.000%	100.000%	100.000%	100.000%
Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%
Investment Interest	3.000%	3.000%	3.000%	3.000%	3.000%
Operating Line Interest	10.000%	10.000%	10.000%	10.000%	10.000%
Accounts Receivable (days)					
Fuel Ethanol	10	10	10	10	10
DDGS	10	10	10	10	10
Accounts Payable (days)					
Denaturants	15	15	15	15	15
Chemicals & Enzymes	15	15	15	15	15
Grain	10	10	10	10	10
Utilities	15	15	15	15	15
Inventories (days)					
Fuel Ethanol	8	8	8	8	8
Distillers Grain	8	8	8	8	8
Denaturants	15	15	15	15	15
Chemicals & Enzymes	20	20	20	20	20
Grain	10	10	10	10	10
Fixed Asset Purchases, years 2-10	$300,000	$250,000	$200,000	$300,000	$300,000
Number of Months of Construction	13	13	13	13	13
First Principal Payment in Month	14	14	14	14	14

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Plant Startup Operating Rate (% of nameplate capacity)					
Month	Rate	Rate	Rate	Rate	Rate
13	0.00%	0.00%	0.00%	0.00%	0.00%
14	100.00%	100.00%	100.00%	100.00%	100.00%
15	100.00%	100.00%	100.00%	100.00%	100.00%
16	100.00%	100.00%	100.00%	100.00%	100.00%
17	100.00%	100.00%	100.00%	100.00%	100.00%
18	100.00%	100.00%	100.00%	100.00%	100.00%
19	100.00%	100.00%	100.00%	100.00%	100.00%
20	100.00%	100.00%	100.00%	100.00%	100.00%
21	100.00%	100.00%	100.00%	100.00%	100.00%
22	100.00%	100.00%	100.00%	100.00%	100.00%
23	100.00%	100.00%	100.00%	100.00%	100.00%
24	100.00%	100.00%	100.00%	100.00%	100.00%
Employees	Annual Salary	Annual Salary	Annual Salary	Annual Salary	Annual Salary
Administration/Management					
General Manager	110,000	110,000	110,000	110,000	110,000
Plant Manager	85,000	85,000	85,000	85,000	85,000
Quality Control Manager	60,000	60,000	60,000	60,000	60,000
Controller	65,000	65,000	65,000	65,000	65,000
Commodity Manager	55,000	55,000	55,000	55,000	55,000
Administrative Assistant	24,000	24,000	24,000	24,000	24,000
Production Labor					
Microbiologist	45,000	45,000	45,000	45,000	45,000
Lab Technician	30,000	30,000	30,000	30,000	30,000
Shift Team Leader	44,000	44,000	44,000	44,000	44,000
Shift Operator	37,000	37,000	37,000	37,000	37,000
Yard/Commodities Labor	27,000	27,000	27,000	27,000	27,000
Maintenance					
Maintenance Manager	55,000	55,000	55,000	55,000	55,000
Boiler Operator	50,000	50,000	50,000	50,000	50,000
Maintenance Worker	37,000	37,000	37,000	37,000	37,000
Welder	42,000	42,000	42,000	42,000	42,000
Electrician	38,000	38,000	38,000	38,000	38,000
Instrument Technician	38,000	38,000	38,000	38,000	38,000
Annual Inflation					
Ethanol Selling Price	2.00%	2.00%	2.00%	2.00%	2.00%
Ethanol Sales Commission	0.00%	0.00%	0.00%	0.00%	0.00%
Ethanol Transportation Cost	2.00%	2.00%	2.00%	2.00%	2.00%
Grain Purchase Price	1.00%	1.00%	1.00%	1.00%	1.00%
Grain Elevator Handling Fee	1.50%	1.50%	1.50%	1.50%	1.50%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
DDGS Price	1.00%	1.00%	1.00%	1.00%	1.00%
DDGS Transportation	1.00%	1.00%	1.00%	1.00%	1.00%
DDGS Sales Commission	0.00%	0.00%	0.00%	0.00%	0.00%
DWG Price	1.00%	1.00%	1.00%	1.00%	1.00%
DWG Transportation	1.00%	1.00%	1.00%	1.00%	1.00%
DWG Sales Commission	0.00%	0.00%	0.00%	0.00%	0.00%
CO2 Price	1.00%	1.00%	1.00%	1.00%	1.00%
Electricity Price	2.00%	2.00%	2.00%	2.00%	2.00%
Natural Gas Price	0.00%	0.00%	0.00%	0.00%	0.00%
Fresh Water Price	1.00%	1.00%	1.00%	1.00%	1.00%
Waste Effluent Price	1.00%	1.00%	1.00%	1.00%	1.00%
Denaturant Price	2.00%	2.00%	2.00%	2.00%	2.00%
Chemicals & Enzymes Cost	1.00%	1.00%	1.00%	1.00%	1.00%
Maintenance Materials & Services	1.50%	1.50%	1.50%	1.50%	1.50%
Insurance	3.00%	3.00%	3.00%	3.00%	3.00%
Property Tax	3.00%	3.00%	3.00%	3.00%	3.00%
Salary Inflation	2.50%	2.50%	2.50%	2.50%	2.50%
Lignite Cost, at mine	2.00%	2.00%	2.00%	2.00%	2.00%
Lignite Transportation Cost	1.50%	1.50%	1.50%	1.50%	1.50%
Lime and Limestone Cost	1.00%	1.00%	1.00%	1.00%	1.00%
Ammonia Cost	1.00%	1.00%	1.00%	1.00%	1.00%
Boiler Ash Disposal Cost	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation for All Other Expense Categories	2.00%	2.00%	2.00%	2.00%	2.00%

END OF USER INPUTS

Financial Model Inputs for Natural Gas-Fired Ethanol Production

Financial Model Inputs	Site #1	Site #2	Site #3	Site #4	Site #5
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512	28,636,884	9,545,628	38,182,512	38,182,512
Small Producer Tax Credit (Yes or No)	No	No	Yes	No	No
CCC Program Payment in Year 2 (Yes or No)	No	No	No	No	No
Capital Cost per Gallon	1.125	1.15	1.50	1.125	1.125
Project Engineering & Construction Costs					
Ethanol Plant Capital Cost	$45,000,000	$34,500,000	$15,000,000	$45,000,000	$45,000,000
Unit Train Rail Improvements	$0	$0	$0	$1,300,000	$1,300,000
Additional Grain Handling and Storage	$0	$0	$0	$1,000,000	$1,000,000
Cogeneration System	$3,000,000	$2,500,000	$1,100,000	$3,000,000	$3,000,000
Total Project Construction Cost	$48,000,000	$37,000,000	$16,100,000	$50,300,000	$50,300,000
Owner's Capital Costs					
Administration Building & Furnishing	$300,000	$300,000	$200,000	$300,000	$300,000
Rail Improvements	$950,000	$850,000	$600,000	$950,000	$950,000
Well & Process Water Treatment	$600,000	$500,000	$300,000	$600,000	$600,000
Site Development Costs	$1,500,000	$1,300,000	$700,000	$1,500,000	$1,500,000
Rolling Stock and Tools	$400,000	$400,000	$300,000	$400,000	$400,000
Organizational Costs	$1,100,000	$1,000,000	$600,000	$1,100,000	$1,100,000
Spare Parts	$450,000	$450,000	$300,000	$450,000	$450,000
Startup Costs	$750,000	$750,000	$600,000	$750,000	$750,000
Contingency	$1,000,000	$800,000	$500,000	$1,000,000	$1,000,000
% of inventory used for operating line of credit	50%	50%	50%	50%	50%
Land - Total Purchase Price	$100,000	$100,000	$50,000	$100,000	$100,000
Land - Number of Acres	40	40	20	40	40
Land - Cost per Acre	$2,500	$2,500	$2,500	$2,500	$2,500
Capitalized Fees & Interest	$1,900,000	$1,500,000	$750,000	$1,900,000	$1,900,000
Operating Days per Year	350	350	350	350	350
1st Year Ethanol Yield (anhydrous gal/bu)	2.670	2.670	2.200	2.670	2.670
2nd Year Ethanol Yield (gal/bu)	2.670	2.670	2.200	2.670	2.670
3rd Year Ethanol Yield (gal/bu)	2.670	2.670	2.200	2.670	2.670
Production increase over Nameplate					
1st Year of operations	0%	0%	0%	0%	0%
2nd Year of operations	5%	5%	5%	5%	5%
3rd Year of operations	5%	5%	5%	5%	5%
State Producer Payment (¢/gal)	$0.040	$0.040	$0.040	$0.040	$0.040
State Producer Payment - Annual Cap ($)	$400,000	$400,000	$400,000	$400,000	$400,000
State Producer Payment - Number of Years	10	10	10	10	10
Ethanol Selling Price ($/gal)	1.27	1.27	1.27	1.27	1.27
Ethanol Sales Commission (% of sales price)	1.000%	1.000%	1.000%	1.000%	1.000%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Ethanol Transportation Cost ($/gal)	0.097	0.097	0.097	0.097	0.097
Grain Purchase Price ($/bu)	2.28	2.15	1.84	2.43	2.43
Grain Price per dry ton	95.80	90.34	90.20	102.10	102.10
Elevator Handling Fee ($/bu)	0.00	0.07	0.07	0.00	0.00
Grain Test Weight (lb/bu)	56	56	48	56	56
% DWG Sold YEAR 1	0%	0%	0%	0%	0%
% DWG Sold YEAR 2	0%	0%	0%	0%	0%
% DWG Sold YEAR 3 through 10	0%	0%	0%	0%	0%
DDGS Moisture %	10%	10%	10%	10%	10%
DDGS Yield (lb/bu)	18.0	18.0	19.0	18.0	18.0
Max. Annual DDGS Production (ton/year)	128,705	96,529	41,220	128,705	128,705
DDGS % of Grain price - dry basis	105%	105%	105%	105%	105%
DDGS Price ($/ton)	90.53	85.37	85.24	96.49	96.49
DDGS Transportation ($/ton)	0.00	0.00	0.00	0.00	0.00
DDGS Sales Commission (% of Price)	2.00%	2.00%	2.00%	2.00%	2.00%
DDGS Sales Commission ($/ton)	1.81	1.71	1.70	1.93	1.93
DWG Moisture %	65%	65%	65%	65%	65%
DWG Yield (lb/bu)	46.3	46.3	46.3	46.3	46.3
Max. Annual DWG Production (ton/year)	330,956	248,217	100,415	330,956	330,956
DWG % of Grain price - dry basis	110%	110%	110%	110%	110%
DWG Price ($/ton)	36.88	34.78	34.73	39.31	39.31
DWG Transportation ($/ton)	0.00	0.00	0.00	0.00	0.00
DWG Sales Commission (% of Price)	2.00%	2.00%	2.00%	2.00%	2.00%
DWG Sales Commission ($/ton)	0.74	0.70	0.69	0.79	0.79
Backup Natural Gas (BTU/anhydrous gal)	38,000	38,000	38,000	38,000	38,000
Annual Natural Gas Use (MCF/year)	1,450,935	1,088,202	362,734	1,450,935	1,450,935
Natural Gas Price ($/MMBTU)					
Lignite Use (tons/year)	0	0	0	0	0
Lignite Cost, at mine ($/ton)	0	0	0	0	0
Lignite Transportation Cost ($/ton)	0	0	0	0	0
Lignite Cost, delivered ($/ton)	0.00	0.00	0.00	0.00	0.00
Lime and Limestone Use (tons/year)	0	0	0	0	0
Lime and Limestone Cost ($/ton)	0	0	0	0	0
Ammonia Use for SCR (tons/year)	0	0	0	0	0
Ammonia Cost ($/tons)	0	0	0	0	0
Boiler Ash Production (ton/year)	0	0	0	0	0
Boiler Ash Disposal Cost ($/ton)	0	0	0	0	0

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
CO2 Produced (lb/gal ethanol)	6.60	6.60	6.60	6.60	6.60
% of CO2 Produced that is Sold	0%	0%	0%	0%	0%
CO2 Sold (lb/gal ethanol)	0.00	0.00	0.00	0.00	0.00
CO2 Price ($/ton)	0.00	0.00	0.00	0.00	0.00
Annual CO2 Sold (tons/year)	0	0	0	0	0
CO2 Sales per Day (tons/day)	0	0	0	0	0
Electricity Use (kWh/gal ethanol)	0.8	0.8	0.8	0.8	0.8
Electricity Price ($/kWh)	0.0450	0.0450	0.0450	0.0450	0.0450
Annual Electricity Use (kWh/year)	30,546,010	22,909,507	7,636,502	30,546,010	30,546,010
Electricity Demand (MW)	3.636	2.727	0.909	3.636	3.636
Makeup Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012
Makeup Water Price ($/1000 gallons)	1.00	1.00	1.00	1.00	1.00
Makeup Water Flow Rate (gpm)	337	252	102	337	337
Daily Makeup Water (gpd)	484,585	363,439	147,027	484,585	484,585
Waste Effluent - % of Makeup Water	20%	20%	20%	20%	20%
Waste Effluent Flow Rate (1000 gal/bu)	0.0024	0.0024	0.0024	0.0024	0.0024
Waste Effluent Price ($/1000 gallons)	2.00	2.00	2.00	2.00	2.00
Waste Effluent Flow Rate (gpm)	67	50	20	67	67
Daily Waste Effluent (gpd)	96,917	72,688	29,405	96,917	96,917
Denaturant Use (% of ethanol sold)	4.76%	4.76%	4.76%	4.76%	4.76%
Denaturant Price ($/gal unleaded gasoline)	0.70	0.70	0.70	0.70	0.70
Chemicals & Enzymes Cost ($/gal ethanol)	0.0700	0.0700	0.0900	0.0700	0.0700
Maintenance Materials & Services (% of Capital Equipment Cost)	2.00%	2.00%	2.00%	2.00%	2.00%
Insurance (% of Depreciated Property, Plant & Equipment)	1.00%	1.00%	1.00%	1.00%	1.00%
Property Tax (% of Depreciated Property, Plant & Equipment)	0.50%	0.50%	0.50%	0.50%	0.50%
Property Tax Abatement (%)	0%	0%	0%	0%	0%
Final Property Tax (% of Depreciated Property, Plant & Equipment)	0.50%	0.50%	0.50%	0.50%	0.50%
Employees	Number	Number	Number	Number	Number
Administration/Management					
General Manager	1	1	1	1	1
Plant Manager	1	1	1	1	1
Quality Control Manager	1	1	0	1	1
Controller	1	1	1	1	1
Commodity Manager	1	1	0	1	1

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Administrative Assistant	2	2	1	2	2
Production Labor					
Microbiologist	1	1	1	1	1
Lab Technician	1	1	1	1	1
Shift Team Leader	4	4	4	4	4
Shift Operator	12	10	4	12	12
Yard/Commodities Labor	4	4	2	4	4
Maintenance					
Maintenance Manager	1	1	0	1	1
Boiler Operator	1	1	0	1	1
Maintenance Worker	2	2	1	2	2
Welder	1	1	1	1	1
Electrician	1	1	1	1	1
Instrument Technician	1	1	1	1	1
Total Number of Employees	36	34	20	36	36
Employee Benefits (% of salary)	30%	30%	30%	30%	30%
Other Expenses - During Construction					
Monthly Legal/Accounting Expenses	$10,000	$10,000	$10,000	$10,000	$10,000
Monthly Community/Governmental Relations	$2,000	$2,000	$2,000	$2,000	$2,000
Other Expenses - During Operations					
Monthly Legal/Accounting Expenses	$2,000	$2,000	$2,000	$2,000	$2,000
Monthly Community/Governmental Relations	$1,000	$1,000	$1,000	$1,000	$1,000
Monthly Office/Lab/Misc. Expenses	$8,000	$8,000	$8,000	$8,000	$8,000
Senior Debt					
Principal (% of Total Project Cost)	0.00%	0.00%	0.00%	0.00%	0.00%
Interest Rate (Fixed Interest Rate)	8.000%	8.000%	8.000%	8.000%	8.000%
Lender Fees (% of Principal)	1.0%	1.0%	1.0%	1.0%	1.0%
Placement Fees (% of Principal)	0.0%	0.0%	0.0%	0.0%	0.0%
Amortization Period (in Years)	10	10	10	10	10
Cash Sweep (% of "excess" cash)	0.000%	0.000%	0.000%	0.000%	0.000%
Subordinated Debt					
Principal ($ amount)	0%	0%	0%	0%	0%
Interest Rate	12.000%	12.000%	12.000%	12.000%	12.000%
Lender Fees (% of Principal)	2.0%	2.0%	2.0%	2.0%	2.0%
Placement Fees (% of Principal)	2.0%	2.0%	2.0%	2.0%	2.0%
Amortization Period (in Years)	10	10	10	10	10
Interest Only Payments? (yes/no)	no	no	no	no	no
Grants - Amount	$0	$0	$0	$0	$0
Economic Development Grant	$0	$0	$0	$0	$0
Other Grants	$0	$0	$0	$0	$0
Percent of Grant applied towards reducing Senior Debt	0%	0%	0%	0%	0%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Common Equity Investment					
Amount	Calculated	Calculated	Calculated	Calculated	Calculated
Placement Fees (% of Principal)	1.0%	1.0%	1.0%	1.0%	1.0%
Preferred Shares (% of total equity)	0.000%	0.000%	0.000%	0.000%	0.000%
Common Shares (% of total equity)	100.000%	100.000%	100.000%	100.000%	100.000%
Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%
Investment Interest	3.000%	3.000%	3.000%	3.000%	3.000%
Operating Line Interest	10.000%	10.000%	10.000%	10.000%	10.000%
Accounts Receivable (days)					
Fuel Ethanol	10	10	10	10	10
DDGS	10	10	10	10	10
Accounts Payable (days)					
Denaturants	15	15	15	15	15
Chemicals & Enzymes	15	15	15	15	15
Grain	10	10	10	10	10
Utilities	15	15	15	15	15
Inventories (days)					
Fuel Ethanol	8	8	8	8	8
Distillers Grain	8	8	8	8	8
Denaturants	15	15	15	15	15
Chemicals & Enzymes	20	20	20	20	20
Grain	10	10	10	10	10
Fixed Asset Purchases, years 2-10	$100,000	$100,000	$50,000	$100,000	$100,000
Number of Months of Construction	13	13	13	13	13
First Principal Payment in Month	14	14	14	14	14
Plant Startup Operating Rate (% of nameplate capacity)					
Month	Rate	Rate	Rate	Rate	Rate
13	0.00%	0.00%	0.00%	0.00%	0.00%
14	100.00%	100.00%	100.00%	100.00%	100.00%
15	100.00%	100.00%	100.00%	100.00%	100.00%
16	100.00%	100.00%	100.00%	100.00%	100.00%
17	100.00%	100.00%	100.00%	100.00%	100.00%
18	100.00%	100.00%	100.00%	100.00%	100.00%
19	100.00%	100.00%	100.00%	100.00%	100.00%
20	100.00%	100.00%	100.00%	100.00%	100.00%
21	100.00%	100.00%	100.00%	100.00%	100.00%
22	100.00%	100.00%	100.00%	100.00%	100.00%
23	100.00%	100.00%	100.00%	100.00%	100.00%
24	100.00%	100.00%	100.00%	100.00%	100.00%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Employees	Annual Salary	Annual Salary	Annual Salary	Annual Salary	Annual Salary
Administration/Management					
General Manager	110,000	110,000	110,000	110,000	110,000
Plant Manager	85,000	85,000	85,000	85,000	85,000
Quality Control Manager	60,000	60,000	60,000	60,000	60,000
Controller	65,000	65,000	65,000	65,000	65,000
Commodity Manager	55,000	55,000	55,000	55,000	55,000
Administrative Assistant	24,000	24,000	24,000	24,000	24,000
Production Labor					
Microbiologist	45,000	45,000	45,000	45,000	45,000
Lab Technician	30,000	30,000	30,000	30,000	30,000
Shift Team Leader	44,000	44,000	44,000	44,000	44,000
Shift Operator	37,000	37,000	37,000	37,000	37,000
Yard/Commodities Labor	27,000	27,000	27,000	27,000	27,000
Maintenance					
Maintenance Manager	55,000	55,000	55,000	55,000	55,000
Boiler Operator	50,000	50,000	50,000	50,000	50,000
Maintenance Worker	37,000	37,000	37,000	37,000	37,000
Welder	42,000	42,000	42,000	42,000	42,000
Electrician	38,000	38,000	38,000	38,000	38,000
Instrument Technician	38,000	38,000	38,000	38,000	38,000
Annual Inflation					
Ethanol Selling Price	2.00%	2.00%	2.00%	2.00%	2.00%
Ethanol Sales Commission	0.00%	0.00%	0.00%	0.00%	0.00%
Ethanol Transportation Cost	2.00%	2.00%	2.00%	2.00%	2.00%
Grain Purchase Price	1.00%	1.00%	1.00%	1.00%	1.00%
Grain Elevator Handling Fee	1.50%	1.50%	1.50%	1.50%	1.50%
DDGS Price	1.00%	1.00%	1.00%	1.00%	1.00%
DDGS Transportation	1.00%	1.00%	1.00%	1.00%	1.00%
DDGS Sales Commission	0.00%	0.00%	0.00%	0.00%	0.00%
DWG Price	1.00%	1.00%	1.00%	1.00%	1.00%
DWG Transportation	1.00%	1.00%	1.00%	1.00%	1.00%
DWG Sales Commission	0.00%	0.00%	0.00%	0.00%	0.00%
CO2 Price	1.00%	1.00%	1.00%	1.00%	1.00%
Electricity Price	2.00%	2.00%	2.00%	2.00%	2.00%
Natural Gas Price	0.00%	0.00%	0.00%	0.00%	0.00%
Fresh Water Price	1.00%	1.00%	1.00%	1.00%	1.00%
Waste Effluent Price	1.00%	1.00%	1.00%	1.00%	1.00%
Denaturant Price	2.00%	2.00%	2.00%	2.00%	2.00%
Chemicals & Enzymes Cost	1.00%	1.00%	1.00%	1.00%	1.00%
Maintenance Materials & Services	1.50%	1.50%	1.50%	1.50%	1.50%
Insurance	3.00%	3.00%	3.00%	3.00%	3.00%
Property Tax	3.00%	3.00%	3.00%	3.00%	3.00%
Salary Inflation	2.50%	2.50%	2.50%	2.50%	2.50%
Lignite Cost, at mine	2.00%	2.00%	2.00%	2.00%	2.00%

Financial Model Inputs	**Site #1**	**Site #2**	**Site #3**	**Site #4**	**Site #5**
Nameplate Denatured Ethanol Production (gal/year)	40,000,000	30,000,000	10,000,000	40,000,000	40,000,000
Lignite Transportation Cost	1.50%	1.50%	1.50%	1.50%	1.50%
Lime and Limestone Cost	1.00%	1.00%	1.00%	1.00%	1.00%
Ammonia Cost	1.00%	1.00%	1.00%	1.00%	1.00%
Boiler Ash Disposal Cost	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation for All Other Expense Categories	2.00%	2.00%	2.00%	2.00%	2.00%

END OF USER INPUTS

APPENDIX B FINANCIAL FORECASTS – LIGNITE-FIRED PLANTS

Financial Forecast for Site #1 – 40 MMGPY Lignite-Fired Plant

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	35,752,381	42,000,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.2800	$2.3028	$2.3258	$2.3491	$2.3726	$2.3963	$2.4203	$2.4445	$2.4689	$2.4936	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Grain Usage (bu/year)	13,108,853	15,015,595	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
		10.7									
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	112,923	135,140	141,897	141,897	141,897	141,897	141,897	141,897	141,897	141,897	
DDGS Price, FOB ($/ton)	$90.529	$91.435	$92.349	$93.273	$94.205	$95.147	$96.099	$97.060	$98.030	$99.011	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$36.882	$37.251	$37.624	$38.000	$38.380	$38.764	$39.151	$39.543	$39.938	$40.338	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	112,622	132,302	138,918	138,918	138,918	138,918	138,918	138,918	138,918	138,918	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	28.001	32.073	33.677	33.677	33.677	33.677	33.677	33.677	33.677	33.677	
Electricity Price ($/kWh)	$0.0040	$0.0041	$0.0042	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	2.00%
Natural Gas Use (MMBTU/bu)	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	
Annual Natural Gas Use (MMBTU/year)	52,501	60,137	63,144	63,144	63,144	63,144	63,144	63,144	63,144	63,144	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	155,471	178,085	186,989	186,989	186,989	186,989	186,989	186,989	186,989	186,989	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	31,094	35,617	37,398	37,398	37,398	37,398	37,398	37,398	37,398	37,398	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,666,030	1,908,362	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	114,855	128,500	128,500	128,500	128,500	128,500	128,500	128,500	128,500	128,500	
Lignite Cost, at mine ($/ton)	$11.0000	$11.2200	$11.4444	$11.6733	$11.9068	$12.1449	$12.3878	$12.6355	$12.8883	$13.1460	2.00%
Lignite Transportation Cost ($/ton)	$12.0000	$12.1800	$12.3627	$12.5481	$12.7364	$12.9274	$13.1213	$13.3181	$13.5179	$13.7207	1.50%
Lignite Cost, delivered ($/ton)	$23.0000	$23.4000	$23.8071	$24.2214	$24.6431	$25.0723	$25.5091	$25.9537	$26.4062	$26.8667	
Lime and Limestone Use (tons/year)	28,602	32,000	32,000	32,000	32,000	32,000	32,000	32,000	32,000	32,000	
Lime and Limestone Cost ($/ton)	$23.0000	$23.2300	$23.4623	$23.6969	$23.9339	$24.1732	$24.4150	$24.6591	$24.9057	$25.1548	1.00%
Ammonia Use for SCR (tons/year)	447	500	500	500	500	500	500	500	500	500	
Ammonia Cost ($/tons)	$340.00	$343.4000	$346.8340	$350.3023	$353.8054	$357.3434	$360.9169	$364.5260	$368.1713	$371.8530	1.00%
Boiler Ash Produced (tons/year)	26,814	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	
Boiler Ash Disposal Cost ($/ton)	$8.0000	$8.1600	$8.3232	$8.4897	$8.6595	$8.8326	$9.0093	$9.1895	$9.3733	$9.5607	2.00%
Number of Employees	51	51	51	51	51	51	51	51	51	51	
Average Salary Including Benefits	$53,325	$54,659	$56,025	$57,426	$58,861	$60,333	$61,841	$63,387	$64,972	$66,596	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$45,000,000
Unit Train Rail Improvements	$0
Additional Grain Handling and Storage	$0
Cogeneration System	$26,300,000
Total Engineering and Construction Cost	$71,300,000
Development Costs	
Inventory - Grain	$854,000
Inventory - Lignite/Chemicals/Denaturant	$404,000
Inventory - Ethanol & DDGS	$911,000
Inventory - Spare Parts	$750,000
Startup Costs	$1,000,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$950,000
Well & Process Water Treatment	$600,000
Site Development Costs	$1,500,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,100,000
Capitalized Fees and Interest	$1,900,000
Contingency	$1,000,000
Total Development Costs	$11,769,000
Total Estimated Project Cost	$83,069,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Cred	No
CCC Bioenergy Program	No

Working Capital at Startup:		
Cash at Startup	$6,780,468	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,459,500	(50% of the value of inventory at startup)
Total Capital at Startup	$8,239,968	
Capital/gallon of capacity	$0.206	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$83,069,000	100.00%
Placement Fees	$830,690	1.000%
Preferred Shares	$0	0.000%
Common Shares	$83,069,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	12,397,912	24,876,794	39,156,424	54,188,738	69,883,051	86,253,979	103,305,818	121,056,043	139,524,750	158,709,679
Accounts Receivable - Trade	0	1,606,405	1,766,260	1,888,104	1,922,269	1,957,079	1,992,549	2,028,689	2,065,513	2,103,036	2,141,269
Inventories											
Feedstock	0	931,580	987,940	1,047,711	1,058,188	1,068,770	1,079,457	1,090,252	1,101,154	1,112,166	1,123,288
Chemicals, Enzymes & Yeast	0	152,730	154,257	155,800	157,358	158,932	160,521	162,126	163,747	165,385	167,039
Denaturant	0	54,525	55,615	56,727	57,862	59,019	60,200	61,404	62,632	63,884	65,162
Finished Product Inventory	0	910,644	1,023,805	1,080,871	1,093,129	1,105,206	1,117,535	1,130,321	1,143,307	1,156,451	1,169,655
Spare Parts	0	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000
Total Inventories	0	2,049,478	2,221,618	2,341,109	2,366,537	2,391,926	2,417,713	2,444,103	2,470,840	2,497,886	2,525,143
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	16,053,794	28,864,672	43,385,637	58,477,544	74,232,057	90,664,240	107,778,610	125,592,397	144,125,671	163,376,091
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	69,307,692	75,800,000	76,100,000	76,400,000	76,700,000	77,000,000	77,300,000	77,600,000	77,900,000	78,200,000	78,500,000
Less Accumulated Depreciation & Amortizatio	0	2,246,454	6,901,739	11,572,023	16,257,308	20,957,592	25,572,877	30,203,161	34,848,446	38,114,668	41,395,890
Net Property, Plant & Equipment	69,307,692	73,553,546	69,198,261	64,827,977	60,442,692	56,042,408	51,727,123	47,396,839	43,051,554	40,085,332	37,104,110
Capitalized Fees & Interest	(1,427,691)	(1,473,759)	(1,326,384)	(1,179,008)	(1,031,632)	(884,256)	(736,880)	(589,504)	(442,128)	(294,752)	(147,376)
Total Assets	67,980,001	88,233,580	96,836,550	107,134,606	117,988,605	129,490,209	141,754,484	154,685,945	168,301,823	184,016,252	200,432,825
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,095,277	1,195,065	1,268,032	1,281,554	1,294,599	1,307,982	1,322,082	1,336,415	1,350,902	1,365,354
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,095,277	1,195,065	1,268,032	1,281,554	1,294,599	1,307,982	1,322,082	1,336,415	1,350,902	1,365,354
Long Term Debt (excluding current maturities)	(13,522,001)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturities	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(13,522,001)	1,095,277	1,195,065	1,268,032	1,281,554	1,294,599	1,307,982	1,322,082	1,336,415	1,350,902	1,365,354
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000	83,069,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,566,998)	4,069,304	12,572,485	22,797,574	33,638,051	45,126,610	57,377,502	70,294,863	83,896,408	99,596,350	115,998,471
Total Capital Shares & Equities	81,502,002	87,138,304	95,641,485	105,866,574	116,707,051	128,195,610	140,446,502	153,363,863	166,965,408	182,665,350	199,067,471
Total Liabilities & Equities	67,980,001	88,233,580	96,836,550	107,134,606	117,988,605	129,490,209	141,754,484	154,685,945	168,301,823	184,016,252	200,432,825

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	41,483,488	49,707,252	53,236,467	54,301,196	55,387,220	56,494,965	57,624,864	58,777,361	59,952,908	61,151,967
DDGS	0	10,018,431	12,111,835	12,847,170	12,978,211	13,110,562	13,244,237	13,379,249	13,515,610	13,653,336	13,792,438
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	51,859,443	62,219,087	66,483,637	67,679,407	68,897,782	70,139,202	71,404,112	72,692,971	74,006,244	75,344,405
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	30,819,764	34,577,912	36,669,875	37,036,574	37,406,940	37,781,009	38,158,819	38,540,407	38,925,812	39,315,070
Chemicals, Enzymes & Yeast	0	2,450,045	2,834,479	3,005,965	3,036,024	3,066,385	3,097,049	3,128,019	3,159,299	3,190,892	3,222,801
Natural Gas or Propane (Statrtup/Backup)	0	224,704	253,179	268,363	274,678	266,469	262,680	272,152	283,518	294,884	301,830
Electricity (Standby Charge)	0	112,002	130,859	140,150	142,953	145,812	148,728	151,703	154,737	157,832	160,988
Denaturants	0	1,166,221	1,362,570	1,459,313	1,488,499	1,518,269	1,548,635	1,579,607	1,611,199	1,643,423	1,676,292
Makeup Water	0	155,471	179,866	190,748	192,655	194,582	196,528	198,493	200,478	202,483	204,507
Wastewater Disposal	0	62,188	71,946	76,299	77,062	77,833	78,611	79,397	80,191	80,993	81,803
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	2,641,654	3,006,900	3,059,212	3,112,454	3,166,640	3,221,790	3,277,920	3,335,048	3,393,192	3,452,371
Lime and Limestone	0	657,844	743,360	750,794	758,302	765,885	773,543	781,279	789,092	796,983	804,952
Ammonia for SCR	0	151,948	171,700	173,417	175,151	176,903	178,672	180,458	182,263	184,086	185,926
Boiler Ash Disposal	0	214,514	244,800	249,696	254,690	259,784	264,979	270,279	275,685	281,198	286,822
Direct Labor & Benefits	0	1,184,300	1,213,908	1,244,255	1,275,362	1,307,246	1,339,927	1,373,425	1,407,761	1,442,955	1,479,028
Total Production Costs	0	39,840,655	44,791,478	47,288,087	47,824,404	48,352,746	48,892,151	49,451,552	50,019,678	50,594,732	51,172,391
Gross Profit	0	12,018,788	17,427,609	19,195,550	19,855,004	20,545,036	21,247,051	21,952,561	22,673,294	23,411,512	24,172,013
Administrative & Operating Expenses											
Maintenance Materials & Services	0	1,307,167	1,447,390	1,469,101	1,491,137	1,513,504	1,536,207	1,559,250	1,582,639	1,606,378	1,630,474
Repairs & Maintenance - Wages & Benefits	0	954,200	978,055	1,002,506	1,027,569	1,053,258	1,079,590	1,106,579	1,134,244	1,162,600	1,191,665
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	208,223	1,041,115	1,137,947	1,102,778	1,064,228	1,022,120	976,267	928,264	876,227	819,946	786,491
Admin. Salaries, Wages & Benefits	264,550	581,100	595,628	610,518	625,781	641,426	657,461	673,898	690,745	708,014	725,714
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,566,998)	7,882,756	13,011,090	14,747,997	15,378,386	16,041,468	16,718,801	17,400,269	18,099,453	18,818,788	19,535,967
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	2,246,454	4,507,909	4,522,909	4,537,909	4,552,909	4,467,909	4,482,909	4,497,909	3,118,846	3,133,846
Pre-Tax Income	(1,566,998)	5,636,302	8,503,181	10,225,089	10,840,477	11,488,559	12,250,892	12,917,361	13,601,545	15,699,942	16,402,121
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,566,998)	5,636,302	8,503,181	10,225,089	10,840,477	11,488,559	12,250,892	12,917,361	13,601,545	15,699,942	16,402,121

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #1
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,566,998)	5,636,302	8,503,181	10,225,089	10,840,477	11,488,559	12,250,892	12,917,361	13,601,545	15,699,942	16,402,121
Non cash charges to operations											
Depreciation & Amortization	0	2,246,454	4,507,909	4,522,909	4,537,909	4,552,909	4,467,909	4,482,909	4,497,909	3,118,846	3,133,846
	(1,566,998)	7,882,756	13,011,090	14,747,997	15,378,386	16,041,468	16,718,801	17,400,269	18,099,453	18,818,788	19,535,967
Changes in non-cash working capital balances											
Accounts Receivable	0	1,606,405	159,855	121,844	34,165	34,811	35,469	36,140	36,825	37,522	38,233
Inventories	0	2,049,478	172,140	119,491	25,428	25,389	25,787	26,390	26,738	27,046	27,257
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,095,277)	(99,788)	(72,968)	(13,521)	(13,045)	(13,383)	(14,101)	(14,333)	(14,487)	(14,452)
	0	2,560,606	232,207	168,367	46,072	47,155	47,873	48,430	49,229	50,081	51,038
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	69,307,692	6,492,308	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Capitalized Fees & Interest	(1,427,691)	(46,068)	0	0	0	0	0	0	0	0	0
	67,980,001	6,446,239	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Financing Activities											
Long Term Debt Advances	(13,522,001)	13,522,001	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	83,069,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	12,397,912	12,478,883	14,279,630	15,032,314	15,694,313	16,370,928	17,051,839	17,750,224	18,468,707	19,184,930
Cash (Indebtedness), Beginning of Year	0	0	12,397,912	24,876,794	39,156,424	54,188,738	69,883,051	86,253,979	103,305,818	121,056,043	139,524,750
Cash (Bank Indebtedness), End of Year	0	12,397,912	24,876,794	39,156,424	54,188,738	69,883,051	86,253,979	103,305,818	121,056,043	139,524,750	158,709,679

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	83,069,000										
Annual Cash Flows	0	12,397,912	12,478,883	14,279,630	15,032,314	15,694,313	16,370,928	17,051,839	17,750,224	18,468,707	19,184,930
Equity & Cash Flows used for IRR & NPV Calcs	(83,069,000)	12,397,912	12,478,883	14,279,630	15,032,314	15,694,313	16,370,928	17,051,839	17,750,224	18,468,707	19,184,930
Internal Rate of Return (IRR)	**12.7%**										
Net Present Value, 8% discount rate	**$18,663,000**										
Net Present Value, 15% discount rate	**($6,768,000)**										

Financial Forecast for Site #2 – 30 MMGPY Lignite-Fired Plant

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	30,000,000
Anhydrous Ethanol Production (gal/year)	28,636,884
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	26,814,286	31,500,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.1500	$2.1715	$2.1932	$2.2151	$2.2373	$2.2597	$2.2823	$2.3051	$2.3281	$2.3514	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0700	$0.0711	$0.0721	$0.0732	$0.0743	$0.0754	$0.0765	$0.0777	$0.0789	$0.0800	1.50%
Grain Usage (bu/year)	9,831,639	11,261,696	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
		10.7									
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	84,693	101,355	106,423	106,423	106,423	106,423	106,423	106,423	106,423	106,423	
DDGS Price, FOB ($/ton)	$85.368	$86.221	$87.084	$87.954	$88.834	$89.722	$90.619	$91.526	$92.441	$93.365	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$34.779	$35.127	$35.478	$35.833	$36.192	$36.554	$36.919	$37.288	$37.661	$38.038	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	84,467	99,227	104,188	104,188	104,188	104,188	104,188	104,188	104,188	104,188	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	21.000	24.055	25.258	25.258	25.258	25.258	25.258	25.258	25.258	25.258	
Electricity Price ($/kWh)	$0.0040	$0.0041	$0.0042	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	2.00%
Natural Gas Use (MMBTU/bu)	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	
Annual Natural Gas Use (MMBTU/year)	39,376	45,103	47,358	47,358	47,358	47,358	47,358	47,358	47,358	47,358	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	116,603	133,564	140,242	140,242	140,242	140,242	140,242	140,242	140,242	140,242	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	23,321	26,713	28,048	28,048	28,048	28,048	28,048	28,048	28,048	28,048	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,249,523	1,431,271	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	86,074	96,300	96,300	96,300	96,300	96,300	96,300	96,300	96,300	96,300	
Lignite Cost, at mine ($/ton)	$11.0000	$11.2200	$11.4444	$11.6733	$11.9068	$12.1449	$12.3878	$12.6355	$12.8883	$13.1460	2.00%
Lignite Transportation Cost ($/ton)	$9.0000	$9.1350	$9.2720	$9.4111	$9.5523	$9.6956	$9.8410	$9.9886	$10.1384	$10.2905	1.50%
Lignite Cost, delivered ($/ton)	$20.0000	$20.3550	$20.7164	$21.0844	$21.4590	$21.8404	$22.2288	$22.6241	$23.0267	$23.4365	
Lime and Limestone Use (tons/year)	21,451	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	
Lime and Limestone Cost ($/ton)	$23.0000	$23.2300	$23.4623	$23.6969	$23.9339	$24.1732	$24.4150	$24.6591	$24.9057	$25.1548	1.00%
Ammonia Use for SCR (tons/year)	331	370	370	370	370	370	370	370	370	370	
Ammonia Cost ($/tons)	$340.00	$343.4000	$346.8340	$350.3023	$353.8054	$357.3434	$360.9169	$364.5260	$368.1713	$371.8530	1.00%
Boiler Ash Produced (tons/year)	19,664	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	
Boiler Ash Disposal Cost ($/ton)	$8.0000	$8.1600	$8.3232	$8.4897	$8.6595	$8.8326	$9.0093	$9.1895	$9.3733	$9.5607	2.00%
Number of Employees	49	49	49	49	49	49	49	49	49	49	
Average Salary Including Benefits	$53,539	$54,877	$56,249	$57,655	$59,097	$60,574	$62,089	$63,641	$65,232	$66,863	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$34,500,000
Unit Train Rail Improvements	$0
Additional Grain Handling and Storage	$0
Cogeneration System	$21,400,000
Total Engineering and Construction Cost	$55,900,000
Development Costs	
Inventory - Grain	$624,000
Inventory - Lignite/Chemicals/Denaturant	$288,000
Inventory - Ethanol & DDGS	$668,000
Inventory - Spare Parts	$750,000
Startup Costs	$1,000,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$850,000
Well & Process Water Treatment	$500,000
Site Development Costs	$1,300,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,000,000
Capitalized Fees and Interest	$1,500,000
Contingency	$800,000
Total Development Costs	$10,080,000
Total Estimated Project Cost	$65,980,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Credit	No
CCC Bioenergy Program	No

Working Capital at Startup:		
Cash at Startup	$5,226,868	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,165,000	(50% of the value of inventory at startup)
Total Capital at Startup	$6,391,868	
Capital/gallon of capacity	$0.213	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$65,980,000	100.00%
Placement Fees	$659,800	1.000%
Preferred Shares	$0	0.000%
Common Shares	$65,980,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations
ASSETS										
Current Assets:										
Cash & Cash Equivalents	0	9,352,351	18,491,520	28,974,405	40,006,443	51,520,856	63,528,324	76,031,338	89,042,689	102,577,135
Accounts Receivable - Trade	0	1,191,240	1,309,896	1,400,381	1,425,845	1,451,791	1,478,230	1,505,170	1,532,622	1,560,595
Inventories										
Feedstock	0	680,298	721,569	765,344	773,119	780,974	788,909	796,926	805,024	813,206
Chemicals, Enzymes & Yeast	0	114,548	115,693	116,850	118,018	119,199	120,391	121,595	122,810	124,039
Denaturant	0	40,893	41,711	42,546	43,396	44,264	45,150	46,053	46,974	47,913
Finished Product Inventory	0	667,594	750,153	792,123	801,266	810,274	819,475	829,020	838,718	848,536
Spare Parts	0	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000
Total Inventories	0	1,503,333	1,629,126	1,716,862	1,735,800	1,754,711	1,773,924	1,793,593	1,813,526	1,833,694
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	12,046,923	21,430,543	32,091,648	43,168,088	54,727,359	66,780,478	79,330,101	92,388,837	105,971,424
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment										
Property, Plant & Equipment, at cost	54,723,077	60,000,000	60,250,000	60,500,000	60,750,000	61,000,000	61,250,000	61,500,000	61,750,000	62,000,000
Less Accumulated Depreciation & Amortization	0	1,785,667	5,486,822	9,200,476	12,926,631	16,665,285	20,316,439	23,980,094	27,656,248	30,247,090
Net Property, Plant & Equipment	54,723,077	58,214,333	54,763,178	51,299,524	47,823,369	44,334,715	40,933,561	37,519,906	34,093,752	31,752,910
Capitalized Fees & Interest	(1,137,600)	(1,173,195)	(1,055,876)	(938,556)	(821,237)	(703,917)	(586,598)	(469,278)	(351,959)	(234,639)
Total Assets	53,685,477	69,188,061	75,237,845	82,552,616	90,270,220	98,458,157	107,227,441	116,480,729	126,230,631	137,589,695
LIABILITIES & EQUITIES										
Current Liabilities:										
Accounts Payable	0	803,582	876,912	930,585	940,644	950,346	960,302	970,798	981,470	992,258
Notes Payable	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	803,582	876,912	930,585	940,644	950,346	960,302	970,798	981,470	992,258
Long Term Debt (excluding current maturities)	(10,771,279)	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(10,771,279)	803,582	876,912	930,585	940,644	950,346	960,302	970,798	981,470	992,258
Capital Shares & Equities										
Preferred Shares	0	0	0	0	0	0	0	0	0	0
Common Shares	65,980,000	65,980,000	65,980,000	65,980,000	65,980,000	65,980,000	65,980,000	65,980,000	65,980,000	65,980,000
Grants	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,523,244)	2,404,479	8,380,933	15,642,031	23,349,577	31,527,811	40,287,139	49,529,931	59,269,160	70,617,437
Total Capital Shares & Equities	64,456,756	68,384,479	74,360,933	81,622,031	89,329,577	97,507,811	106,267,139	115,509,931	125,249,160	136,597,437
Total Liabilities & Equities	53,685,477	69,188,061	75,237,845	82,552,616	90,270,220	98,458,157	107,227,441	116,480,729	126,230,631	137,589,695

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations
Revenue										
Ethanol	0	31,112,616	37,280,439	39,927,350	40,725,897	41,540,415	42,371,223	43,218,648	44,083,021	44,964,681
DDGS	0	7,085,404	8,565,936	9,085,992	9,178,669	9,272,273	9,366,812	9,462,298	9,558,738	9,656,142
DWG	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	38,555,543	46,246,375	49,413,342	50,304,566	51,212,688	52,138,036	53,080,945	54,041,758	55,020,823
Ethanol Plant Production & Operating Expenses										
Feedstocks	0	22,506,538	25,254,917	26,787,040	27,059,174	27,334,093	27,611,827	27,892,404	28,175,853	28,462,205
Chemicals, Enzymes & Yeast	0	1,837,533	2,125,859	2,254,474	2,277,018	2,299,789	2,322,786	2,346,014	2,369,474	2,393,169
Natural Gas or Propane (Statrtup/Backup)	0	168,528	189,884	201,273	206,008	199,852	197,010	204,114	212,639	221,163
Electricity (Standby Charge)	0	84,002	98,144	105,113	107,215	109,359	111,546	113,777	116,053	118,374
Denaturants	0	874,666	1,021,928	1,094,485	1,116,374	1,138,702	1,161,476	1,184,705	1,208,400	1,232,568
Makeup Water	0	116,603	134,899	143,061	144,491	145,936	147,396	148,870	150,358	151,862
Wastewater Disposal	0	46,641	53,960	57,224	57,797	58,375	58,958	59,548	60,143	60,745
Cogen Plant Production & Operating Expenses										
Lignite Fuel (delivered)	0	1,721,477	1,960,187	1,994,992	2,030,427	2,066,504	2,103,235	2,140,631	2,178,705	2,217,470
Lime and Limestone	0	493,383	557,520	563,095	568,726	574,413	580,158	585,959	591,819	597,737
Ammonia for SCR	0	112,441	127,058	128,329	129,612	130,908	132,217	133,539	134,875	136,223
Boiler Ash Disposal	0	157,310	179,520	183,110	186,773	190,508	194,318	198,205	202,169	206,212
Direct Labor & Benefits	0	1,088,100	1,115,303	1,143,185	1,171,765	1,201,059	1,231,085	1,261,862	1,293,409	1,325,744
Total Production Costs	0	29,207,223	32,819,178	34,655,379	35,055,380	35,449,498	35,852,013	36,269,629	36,693,896	37,123,472
Gross Profit	0	9,348,320	13,427,197	14,757,963	15,249,186	15,763,190	16,286,023	16,811,317	17,347,862	17,897,352
Administrative & Operating Expenses										
Maintenance Materials & Services	0	1,024,833	1,134,770	1,151,792	1,169,068	1,186,604	1,204,404	1,222,470	1,240,807	1,259,419
Repairs & Maintenance - Wages & Benefits	0	954,200	978,055	1,002,506	1,027,569	1,053,258	1,079,590	1,106,579	1,134,244	1,162,600
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373
Property Taxes & Insurance	164,469	822,346	900,956	873,065	842,485	809,073	772,680	734,943	694,016	649,734
Admin. Salaries, Wages & Benefits	264,550	581,100	595,628	610,518	625,781	641,426	657,461	673,898	690,745	708,014
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419
EBITDA	(1,523,244)	5,713,391	9,560,289	10,857,433	11,316,381	11,799,569	12,293,163	12,789,127	13,298,064	13,821,799
Less:										
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	1,785,667	3,583,835	3,596,335	3,608,835	3,621,335	3,533,835	3,546,335	3,558,835	2,473,522
Pre-Tax Income	(1,523,244)	3,927,723	5,976,454	7,261,098	7,707,546	8,178,234	8,759,328	9,242,792	9,739,229	11,348,277
Current Income Taxes	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,523,244)	3,927,723	5,976,454	7,261,098	7,707,546	8,178,234	8,759,328	9,242,792	9,739,229	11,348,277

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #2
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,523,244)	3,927,723	5,976,454	7,261,098	7,707,546	8,178,234	8,759,328	9,242,792	9,739,229	11,348,277	11,856,553
Non cash charges to operations											
Depreciation & Amortization	0	1,785,667	3,583,835	3,596,335	3,608,835	3,621,335	3,533,835	3,546,335	3,558,835	2,473,522	2,486,022
	(1,523,244)	5,713,391	9,560,289	10,857,433	11,316,381	11,799,569	12,293,163	12,789,127	13,298,064	13,821,799	14,342,575
Changes in non-cash working capital balances											
Accounts Receivable	0	1,191,240	118,657	90,485	25,464	25,946	26,439	26,940	27,452	27,973	28,505
Inventories	0	1,503,333	125,793	87,736	18,938	18,911	19,213	19,669	19,933	20,168	20,330
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(803,582)	(73,330)	(53,673)	(10,058)	(9,702)	(9,956)	(10,496)	(10,672)	(10,788)	(10,763)
	0	1,890,991	171,119	124,548	34,343	35,155	35,695	36,113	36,713	37,353	38,072
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	54,723,077	5,276,923	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Capitalized Fees & Interest	(1,137,600)	(35,595)	0	0	0	0	0	0	0	0	0
	53,685,477	5,241,328	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Financing Activities											
Long Term Debt Advances	(10,771,279)	10,771,279	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	65,980,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	9,352,351	9,139,170	10,482,884	11,032,038	11,514,413	12,007,468	12,503,014	13,011,351	13,534,446	14,054,504
Cash (Indebtedness), Beginning of Year	0	0	9,352,351	18,491,520	28,974,405	40,006,443	51,520,856	63,528,324	76,031,338	89,042,689	102,577,135
Cash (Bank Indebtedness), End of Year	0	9,352,351	18,491,520	28,974,405	40,006,443	51,520,856	63,528,324	76,031,338	89,042,689	102,577,135	116,631,639

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	65,980,000										
Annual Cash Flows	0	9,352,351	9,139,170	10,482,884	11,032,038	11,514,413	12,007,468	12,503,014	13,011,351	13,534,446	14,054,504
Equity & Cash Flows used for IRR & NPV Calcs	(65,980,000)	9,352,351	9,139,170	10,482,884	11,032,038	11,514,413	12,007,468	12,503,014	13,011,351	13,534,446	14,054,504
Internal Rate of Return (IRR)	**11.0%**										
Net Present Value, 8% discount rate	**$9,217,000**										
Net Present Value, 15% discount rate	**($9,170,000)**										

Financial Forecast for Site #3 – 10 MMGPY Lignite-Fired Plant

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	10,000,000
Anhydrous Ethanol Production (gal/year)	9,545,628
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	
Denatured Ethanol Sold (gal/year)	8,938,095	10,500,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$1.8400	$1.8584	$1.8770	$1.8958	$1.9147	$1.9339	$1.9532	$1.9727	$1.9925	$2.0124	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0700	$0.0711	$0.0721	$0.0732	$0.0743	$0.0754	$0.0765	$0.0777	$0.0789	$0.0800	1.50%
Grain Usage (bu/year)	3,977,345	4,555,868	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	
Grain Test Weight (lb/bu)	48.000	48.000	48.000	48.000	48.000	48.000	48.000	48.000	48.000	48.000	
		10.7									
DDGS Yield (lb/bu)	19.000	19.000	19.000	19.000	19.000	19.000	19.000	19.000	19.000	19.000	
DDGS Sold (ton/year)	36,165	43,281	45,445	45,445	45,445	45,445	45,445	45,445	45,445	45,445	
DDGS Price, FOB ($/ton)	$85.235	$86.088	$86.949	$87.818	$88.696	$89.583	$90.479	$91.384	$92.298	$93.221	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$34.725	$35.073	$35.423	$35.778	$36.135	$36.497	$36.862	$37.230	$37.603	$37.979	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	28,156	33,076	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	1.509	1.509	1.509	1.509	1.509	1.509	1.509	1.509	1.509	1.509	
Annual Electricity Use (million kWh/year)	6.000	6.873	7.216	7.216	7.216	7.216	7.216	7.216	7.216	7.216	
Electricity Price ($/kWh)	$0.0040	$0.0041	$0.0042	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	2.00%
Natural Gas Use (MMBTU/bu)	0.0033	0.0033	0.0033	0.0033	0.0033	0.0033	0.0033	0.0033	0.0033	0.0033	
Annual Natural Gas Use (MMBTU/year)	13,125	15,034	15,786	15,786	15,786	15,786	15,786	15,786	15,786	15,786	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	
Annual Fresh Water Use (1000 gal/year)	40,433	46,314	48,629	48,629	48,629	48,629	48,629	48,629	48,629	48,629	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	8,087	9,263	9,726	9,726	9,726	9,726	9,726	9,726	9,726	9,726	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	416,508	477,090	500,945	500,945	500,945	500,945	500,945	500,945	500,945	500,945	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0900	$0.0909	$0.0918	$0.0927	$0.0937	$0.0946	$0.0955	$0.0965	$0.0975	$0.0984	1.00%
Lignite Use (tons/year)	28,691	32,100	32,100	32,100	32,100	32,100	32,100	32,100	32,100	32,100	
Lignite Cost, at mine ($/ton)	$11.0000	$11.2200	$11.4444	$11.6733	$11.9068	$12.1449	$12.3878	$12.6355	$12.8883	$13.1460	2.00%
Lignite Transportation Cost ($/ton)	$12.0000	$12.1800	$12.3627	$12.5481	$12.7364	$12.9274	$13.1213	$13.3181	$13.5179	$13.7207	1.50%
Lignite Cost, delivered ($/ton)	$23.0000	$23.4000	$23.8071	$24.2214	$24.6431	$25.0723	$25.5091	$25.9537	$26.4062	$26.8667	
Lime and Limestone Use (tons/year)	7,150	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	
Lime and Limestone Cost ($/ton)	$23.0000	$23.2300	$23.4623	$23.6969	$23.9339	$24.1732	$24.4150	$24.6591	$24.9057	$25.1548	1.00%
Ammonia Use for SCR (tons/year)	112	125	125	125	125	125	125	125	125	125	
Ammonia Cost ($/tons)	$340.00	$343.4000	$346.8340	$350.3023	$353.8054	$357.3434	$360.9169	$364.5260	$368.1713	$371.8530	1.00%
Boiler Ash Produced (tons/year)	6,525	7,300	7,300	7,300	7,300	7,300	7,300	7,300	7,300	7,300	
Boiler Ash Disposal Cost ($/ton)	$8.0000	$8.1600	$8.3232	$8.4897	$8.6595	$8.8326	$9.0093	$9.1895	$9.3733	$9.5607	2.00%
Number of Employees	35	35	35	35	35	35	35	35	35	35	
Average Salary Including Benefits	$56,606	$58,021	$59,471	$60,958	$62,482	$64,044	$65,645	$67,286	$68,969	$70,693	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$15,000,000
Unit Train Rail Improvements	$0
Additional Grain Handling and Storage	$0
Cogeneration System	$12,200,000
Total Engineering and Construction Cost	$27,200,000
Development Costs	
Inventory - Grain	$217,000
Inventory - Lignite/Chemicals/Denaturant	$112,000
Inventory - Ethanol & DDGS	$247,000
Inventory - Spare Parts	$500,000
Startup Costs	$800,000
Land	$50,000
Administration Building & Furnishing	$200,000
Rail Improvements	$600,000
Well & Process Water Treatment	$300,000
Site Development Costs	$700,000
Rolling Stock and Shop Equipment	$300,000
Organizational Costs	$600,000
Capitalized Fees and Interest	$750,000
Contingency	$500,000
Total Development Costs	$5,876,000
Total Estimated Project Cost	$33,076,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Credit	Yes
CCC Bioenergy Program	No

Working Capital at Startup:		
Cash at Startup	$2,083,871	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$538,000	(50% of the value of inventory at startup)
Total Capital at Startup	$2,621,871	
Capital/gallon of capacity	$0.262	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$33,076,000	100.00%
Placement Fees	$330,760	1.000%
Preferred Shares	$0	0.000%
Common Shares	$33,076,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	3,268,680	6,011,474	9,237,124	12,617,016	16,127,171	19,770,799	23,547,672	27,461,681	31,517,379	35,709,989
Accounts Receivable - Trade	0	417,948	459,399	490,943	499,677	508,575	517,639	526,873	536,280	545,863	555,626
Inventories											
Feedstock	0	236,781	251,152	266,395	269,108	271,850	274,619	277,417	280,243	283,099	285,983
Chemicals, Enzymes & Yeast	0	49,092	49,583	50,079	50,579	51,085	51,596	52,112	52,633	53,159	53,691
Denaturant	0	13,631	13,904	14,182	14,465	14,755	15,050	15,351	15,658	15,971	16,290
Finished Product Inventory	0	247,209	276,826	291,933	295,453	298,937	302,495	306,177	309,921	313,715	317,535
Spare Parts	0	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Total Inventories	0	546,713	591,464	622,589	629,606	636,626	643,759	651,057	658,455	665,944	673,500
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	4,233,341	7,062,337	10,350,655	13,746,299	17,272,372	20,932,197	24,725,602	28,656,415	32,729,185	36,939,115
Land	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	27,069,231	29,800,000	30,000,000	30,200,000	30,400,000	30,600,000	30,800,000	31,000,000	31,200,000	31,400,000	31,600,000
Less Accumulated Depreciation & Amortization	0	899,078	2,765,057	4,641,036	6,527,015	8,422,995	10,255,640	12,098,286	13,950,932	15,273,578	16,606,224
Net Property, Plant & Equipment	27,069,231	28,900,922	27,234,943	25,558,964	23,872,985	22,177,005	20,544,360	18,901,714	17,249,068	16,126,422	14,993,776
Capitalized Fees & Interest	(563,511)	(578,233)	(520,410)	(462,587)	(404,763)	(346,940)	(289,117)	(231,293)	(173,470)	(115,647)	(57,823)
Total Assets	26,555,719	32,606,030	33,826,870	35,497,032	37,264,520	39,152,437	41,237,440	43,446,022	45,782,013	48,789,961	51,925,068
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	285,470	311,518	330,578	334,141	337,588	341,122	344,837	348,614	352,431	356,243
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	285,470	311,518	330,578	334,141	337,588	341,122	344,837	348,614	352,431	356,243
Long Term Debt (excluding current maturities)	(5,123,806)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(5,123,806)	285,470	311,518	330,578	334,141	337,588	341,122	344,837	348,614	352,431	356,243
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000	33,076,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,396,474)	(755,440)	439,352	2,090,454	3,854,379	5,738,849	7,820,318	10,025,185	12,357,400	15,361,529	18,492,825
Total Capital Shares & Equities	31,679,526	32,320,560	33,515,352	35,166,454	36,930,379	38,814,849	40,896,318	43,101,185	45,433,400	48,437,529	51,568,825
Total Liabilities & Equities	26,555,719	32,606,030	33,826,870	35,497,032	37,264,520	39,152,437	41,237,440	43,446,022	45,782,013	48,789,961	51,925,068

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	10,370,872	12,426,813	13,309,117	13,575,299	13,846,805	14,123,741	14,406,216	14,694,340	14,988,227	15,287,992
DDGS	0	3,020,920	3,652,157	3,873,887	3,913,400	3,953,309	3,993,617	4,034,328	4,075,446	4,116,975	4,158,919
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	893,810	1,050,000	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	14,643,125	17,528,970	18,685,504	18,991,199	19,302,614	19,619,858	19,943,044	20,272,286	20,607,702	20,949,411
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	7,833,510	8,790,319	9,323,833	9,418,796	9,514,735	9,611,659	9,709,580	9,808,506	9,908,450	10,009,420
Chemicals, Enzymes & Yeast	0	787,514	911,082	966,203	975,865	985,624	995,480	1,005,435	1,015,489	1,025,644	1,035,900
Natural Gas or Propane (Statrtup/Backup)	0	56,176	63,295	67,091	68,669	66,617	65,670	68,038	70,880	73,721	75,457
Electricity (Standby Charge)	0	24,000	28,041	30,032	30,633	31,245	31,870	32,508	33,158	33,821	34,498
Denaturants	0	291,555	340,643	364,828	372,125	379,567	387,159	394,902	402,800	410,856	419,073
Makeup Water	0	40,433	46,777	49,607	50,103	50,604	51,110	51,621	52,137	52,659	53,185
Wastewater Disposal	0	16,173	18,711	19,843	20,041	20,242	20,444	20,648	20,855	21,063	21,274
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	659,900	751,140	764,208	777,508	791,044	804,821	818,842	833,113	847,638	862,421
Lime and Limestone	0	164,461	185,840	187,698	189,575	191,471	193,386	195,320	197,273	199,246	201,238
Ammonia for SCR	0	37,987	42,925	43,354	43,788	44,226	44,668	45,115	45,566	46,021	46,482
Boiler Ash Disposal	0	52,198	59,568	60,759	61,975	63,214	64,478	65,768	67,083	68,425	69,793
Direct Labor & Benefits	0	851,500	872,788	894,607	916,972	939,897	963,394	987,479	1,012,166	1,037,470	1,063,407
Total Production Costs	0	10,815,408	12,111,128	12,772,064	12,926,050	13,078,486	13,234,139	13,395,255	13,559,026	13,725,013	13,892,149
Gross Profit	0	3,827,717	5,417,841	5,913,440	6,065,149	6,224,128	6,385,719	6,547,789	6,713,260	6,882,689	7,057,262
Administrative & Operating Expenses											
Maintenance Materials & Services	0	498,667	552,160	560,442	568,849	577,382	586,042	594,833	603,756	612,812	622,004
Repairs & Maintenance - Wages & Benefits	0	760,500	779,513	799,000	818,975	839,450	860,436	881,947	903,996	926,595	949,760
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	81,358	406,788	447,292	434,199	419,754	403,883	386,508	368,861	349,623	328,709	316,598
Admin. Salaries, Wages & Benefits	220,892	369,200	378,430	387,891	397,588	407,528	417,716	428,159	438,863	449,834	461,080
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,396,474)	1,540,112	3,002,948	3,469,258	3,592,081	3,722,626	3,856,291	3,989,689	4,127,037	4,268,952	4,406,118
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	899,078	1,808,156	1,818,156	1,828,156	1,838,156	1,774,823	1,784,823	1,794,823	1,264,823	1,274,823
Pre-Tax Income	(1,396,474)	641,034	1,194,792	1,651,102	1,763,925	1,884,470	2,081,469	2,204,867	2,332,215	3,004,130	3,131,296
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,396,474)	641,034	1,194,792	1,651,102	1,763,925	1,884,470	2,081,469	2,204,867	2,332,215	3,004,130	3,131,296

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #3
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,396,474)	641,034	1,194,792	1,651,102	1,763,925	1,884,470	2,081,469	2,204,867	2,332,215	3,004,130	3,131,296
Non cash charges to operations											
Depreciation & Amortization	0	899,078	1,808,156	1,818,156	1,828,156	1,838,156	1,774,823	1,784,823	1,794,823	1,264,823	1,274,823
	(1,396,474)	1,540,112	3,002,948	3,469,258	3,592,081	3,722,626	3,856,291	3,989,689	4,127,037	4,268,952	4,406,118
Changes in non-cash working capital balances											
Accounts Receivable	0	417,948	41,452	31,544	8,734	8,898	9,064	9,234	9,407	9,583	9,763
Inventories	0	546,713	44,751	31,124	7,017	7,020	7,133	7,297	7,398	7,489	7,556
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(285,470)	(26,048)	(19,060)	(3,563)	(3,447)	(3,534)	(3,716)	(3,776)	(3,817)	(3,812)
	0	679,191	60,154	43,608	12,188	12,471	12,664	12,816	13,028	13,255	13,508
Investing Activities											
Land Purchase	50,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	27,069,231	2,730,769	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Capitalized Fees & Interest	(563,511)	(14,722)	0	0	0	0	0	0	0	0	0
	26,555,719	2,716,047	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Financing Activities											
Long Term Debt Advances	(5,123,806)	5,123,806	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	33,076,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	3,268,680	2,742,794	3,225,650	3,379,892	3,510,155	3,643,628	3,776,874	3,914,009	4,055,698	4,192,610
Cash (Indebtedness), Beginning of Year	0	0	3,268,680	6,011,474	9,237,124	12,617,016	16,127,171	19,770,799	23,547,672	27,461,681	31,517,379
Cash (Bank Indebtedness), End of Year	0	3,268,680	6,011,474	9,237,124	12,617,016	16,127,171	19,770,799	23,547,672	27,461,681	31,517,379	35,709,989

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	33,076,000										
Annual Cash Flows	0	3,268,680	2,742,794	3,225,650	3,379,892	3,510,155	3,643,628	3,776,874	3,914,009	4,055,698	4,192,610
Equity & Cash Flows used for IRR & NPV Calcs	(33,076,000)	3,268,680	2,742,794	3,225,650	3,379,892	3,510,155	3,643,628	3,776,874	3,914,009	4,055,698	4,192,610
Internal Rate of Return (IRR)	**1.3%**										
Net Present Value, 8% discount rate	**($8,962,000)**										
Net Present Value, 15% discount rate	**($13,824,000)**										

Financial Forecast for Site #4 – 40 MMGPY Lignite-Fired Plant

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #4
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	35,752,381	42,000,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.4300	$2.4543	$2.4788	$2.5036	$2.5287	$2.5540	$2.5795	$2.6053	$2.6313	$2.6577	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Grain Usage (bu/year)	13,108,853	15,015,595	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
		10.7									
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	112,923	135,140	141,897	141,897	141,897	141,897	141,897	141,897	141,897	141,897	
DDGS Price, FOB ($/ton)	$96.485	$97.450	$98.425	$99.409	$100.403	$101.407	$102.421	$103.445	$104.480	$105.525	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$39.309	$39.702	$40.099	$40.500	$40.905	$41.314	$41.727	$42.144	$42.566	$42.991	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	112,622	132,302	138,918	138,918	138,918	138,918	138,918	138,918	138,918	138,918	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	28.001	32.073	33.677	33.677	33.677	33.677	33.677	33.677	33.677	33.677	
Electricity Price ($/kWh)	$0.0040	$0.0041	$0.0042	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	2.00%
Natural Gas Use (MMBTU/bu)	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	
Annual Natural Gas Use (MMBTU/year)	52,501	60,137	63,144	63,144	63,144	63,144	63,144	63,144	63,144	63,144	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	155,471	178,085	186,989	186,989	186,989	186,989	186,989	186,989	186,989	186,989	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	31,094	35,617	37,398	37,398	37,398	37,398	37,398	37,398	37,398	37,398	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #4
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,666,030	1,908,362	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	114,855	128,500	128,500	128,500	128,500	128,500	128,500	128,500	128,500	128,500	
Lignite Cost, at mine ($/ton)	$11.0000	$11.2200	$11.4444	$11.6733	$11.9068	$12.1449	$12.3878	$12.6355	$12.8883	$13.1460	2.00%
Lignite Transportation Cost ($/ton)	$3.0000	$3.0450	$3.0907	$3.1370	$3.1841	$3.2319	$3.2803	$3.3295	$3.3795	$3.4302	1.50%
Lignite Cost, delivered ($/ton)	$14.0000	$14.2650	$14.5351	$14.8103	$15.0908	$15.3767	$15.6681	$15.9651	$16.2677	$16.5762	
Lime and Limestone Use (tons/year)	28,602	32,000	32,000	32,000	32,000	32,000	32,000	32,000	32,000	32,000	
Lime and Limestone Cost ($/ton)	$23.0000	$23.2300	$23.4623	$23.6969	$23.9339	$24.1732	$24.4150	$24.6591	$24.9057	$25.1548	1.00%
Ammonia Use for SCR (tons/year)	447	500	500	500	500	500	500	500	500	500	
Ammonia Cost ($/tons)	$340.00	$343.4000	$346.8340	$350.3023	$353.8054	$357.3434	$360.9169	$364.5260	$368.1713	$371.8530	1.00%
Boiler Ash Produced (tons/year)	26,814	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	
Boiler Ash Disposal Cost ($/ton)	$8.0000	$8.1600	$8.3232	$8.4897	$8.6595	$8.8326	$9.0093	$9.1895	$9.3733	$9.5607	2.00%
Number of Employees	51	51	51	51	51	51	51	51	51	51	
Average Salary Including Benefits	$53,325	$54,659	$56,025	$57,426	$58,861	$60,333	$61,841	$63,387	$64,972	$66,596	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #4
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$45,000,000
Unit Train Rail Improvements	$1,300,000
Additional Grain Handling and Storage	$1,000,000
Cogeneration System	$26,300,000
Total Engineering and Construction Cost	$73,600,000
Development Costs	
Inventory - Grain	$910,000
Inventory - Lignite/Chemicals/Denaturant	$345,000
Inventory - Ethanol & DDGS	$933,000
Inventory - Spare Parts	$750,000
Startup Costs	$1,000,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$950,000
Well & Process Water Treatment	$600,000
Site Development Costs	$1,500,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,100,000
Capitalized Fees and Interest	$1,900,000
Contingency	$1,000,000
Total Development Costs	$11,788,000
Total Estimated Project Cost	$85,388,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment		Other Incentive Payments	
Producer payment, $/gal	$0.0400	Small Producer Tax Credi	No
Annual payment cap	$400,000	CCC Bioenergy Program	No
Incentive duration, years	10		

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Working Capital at Startup:		
Cash at Startup	$6,754,166	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,469,000	(50% of the value of inventory at startup)
Total Capital at Startup	$8,223,166	
Capital/gallon of capacity	$0.206	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$85,388,000	100.00%
Placement Fees	$853,880	1.000%
Preferred Shares	$0	0.000%
Common Shares	$85,388,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #4
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	11,990,544	24,081,413	37,900,366	52,478,658	67,722,076	83,645,449	100,253,300	117,563,331	135,595,881	154,348,095
Accounts Receivable - Trade	0	1,627,272	1,789,026	1,912,253	1,946,664	1,981,723	2,017,444	2,053,838	2,090,919	2,128,700	2,167,194
Inventories											
Feedstock	0	992,868	1,052,936	1,116,639	1,127,805	1,139,084	1,150,474	1,161,979	1,173,599	1,185,335	1,197,188
Chemicals, Enzymes & Yeast	0	152,730	154,257	155,800	157,358	158,932	160,521	162,126	163,747	165,385	167,039
Denaturant	0	54,525	55,615	56,727	57,862	59,019	60,200	61,404	62,632	63,884	65,162
Finished Product Inventory	0	933,362	1,048,971	1,108,780	1,121,182	1,133,400	1,145,871	1,158,798	1,171,924	1,185,208	1,198,550
Spare Parts	0	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000
Total Inventories	0	2,133,484	2,311,780	2,437,946	2,464,207	2,490,434	2,517,066	2,544,307	2,571,902	2,599,812	2,627,939
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	15,751,300	28,182,220	42,250,565	56,889,529	72,194,234	88,179,959	104,851,445	122,226,152	140,324,393	159,143,229
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	71,430,769	78,100,000	78,400,000	78,700,000	79,000,000	79,300,000	79,600,000	79,900,000	80,200,000	80,500,000	80,800,000
Less Accumulated Depreciation & Amortizat	0	2,313,762	7,107,075	11,915,388	16,738,700	21,577,013	26,330,326	31,098,639	35,881,951	39,243,076	42,619,202
Net Property, Plant & Equipment	71,430,769	75,786,238	71,292,925	66,784,612	62,261,300	57,722,987	53,269,674	48,801,361	44,318,049	41,256,924	38,180,798
Capitalized Fees & Interest	(1,461,460)	(1,507,880)	(1,357,092)	(1,206,304)	(1,055,516)	(904,728)	(753,940)	(603,152)	(452,364)	(301,576)	(150,788)
Total Assets	70,069,309	90,129,658	98,218,052	107,928,873	118,195,313	129,112,493	140,795,693	153,149,654	166,191,837	181,379,740	197,273,239
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,154,862	1,260,061	1,336,961	1,351,171	1,364,913	1,378,999	1,393,809	1,408,860	1,424,071	1,439,255
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,154,862	1,260,061	1,336,961	1,351,171	1,364,913	1,378,999	1,393,809	1,408,860	1,424,071	1,439,255
Long Term Debt (excluding current maturities)	(13,745,323)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturiti	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(13,745,323)	1,154,862	1,260,061	1,336,961	1,351,171	1,364,913	1,378,999	1,393,809	1,408,860	1,424,071	1,439,255
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000	85,388,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,573,367)	3,586,796	11,569,992	21,203,913	31,456,141	42,359,580	54,028,695	66,367,845	79,394,977	94,567,670	110,445,984
Total Capital Shares & Equities	83,814,633	88,974,796	96,957,992	106,591,913	116,844,141	127,747,580	139,416,695	151,755,845	164,782,977	179,955,670	195,833,984
Total Liabilities & Equities	70,069,309	90,129,658	98,218,052	107,928,873	118,195,313	129,112,493	140,795,693	153,149,654	166,191,837	181,379,740	197,273,239

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #4
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	41,483,488	49,707,252	53,236,467	54,301,196	55,387,220	56,494,965	57,624,864	58,777,361	59,952,908	61,151,967
DDGS	0	10,677,539	12,908,666	13,692,379	13,832,041	13,973,099	14,115,568	14,259,462	14,404,795	14,551,581	14,699,835
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	52,518,550	63,015,918	67,328,846	68,533,237	69,760,319	71,010,533	72,284,326	73,582,156	74,904,490	76,251,802
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	32,847,380	36,852,774	39,082,367	39,473,191	39,867,923	40,266,602	40,669,268	41,075,961	41,486,720	41,901,587
Chemicals, Enzymes & Yeast	0	2,450,045	2,834,479	3,005,965	3,036,024	3,066,385	3,097,049	3,128,019	3,159,299	3,190,892	3,222,801
Natural Gas or Propane (Statrtup/Backup)	0	224,704	253,179	268,363	274,678	266,469	262,680	272,152	283,518	294,884	301,830
Electricity (Standby Charge)	0	112,002	130,859	140,150	142,953	145,812	148,728	151,703	154,737	157,832	160,988
Denaturants	0	1,166,221	1,362,570	1,459,313	1,488,499	1,518,269	1,548,635	1,579,607	1,611,199	1,643,423	1,676,292
Makeup Water	0	155,471	179,866	190,748	192,655	194,582	196,528	198,493	200,478	202,483	204,507
Wastewater Disposal	0	62,188	71,946	76,299	77,062	77,833	78,611	79,397	80,191	80,993	81,803
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	1,607,963	1,833,053	1,867,757	1,903,127	1,939,174	1,975,911	2,013,353	2,051,512	2,090,403	2,130,040
Lime and Limestone	0	657,844	743,360	750,794	758,302	765,885	773,543	781,279	789,092	796,983	804,952
Ammonia for SCR	0	151,948	171,700	173,417	175,151	176,903	178,672	180,458	182,263	184,086	185,926
Boiler Ash Disposal	0	214,514	244,800	249,696	254,690	259,784	264,979	270,279	275,685	281,198	286,822
Direct Labor & Benefits	0	1,184,300	1,213,908	1,244,255	1,275,362	1,307,246	1,339,927	1,373,425	1,407,761	1,442,955	1,479,028
Total Production Costs	0	40,834,580	45,892,493	48,509,124	49,051,693	49,586,262	50,131,865	50,697,433	51,271,695	51,852,851	52,436,579
Gross Profit	0	11,683,970	17,123,425	18,819,722	19,481,544	20,174,057	20,878,668	21,586,893	22,310,461	23,051,638	23,815,223
Administrative & Operating Expenses											
Maintenance Materials & Services	0	1,349,333	1,494,080	1,516,491	1,539,239	1,562,327	1,585,762	1,609,548	1,633,692	1,658,197	1,683,070
Repairs & Maintenance - Wages & Benefits	0	954,200	978,055	1,002,506	1,027,569	1,053,258	1,079,590	1,106,579	1,134,244	1,162,600	1,191,665
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	214,592	1,072,962	1,172,442	1,136,111	1,096,299	1,052,823	1,005,490	955,893	902,138	844,012	809,421
Admin. Salaries, Wages & Benefits	264,550	581,100	595,628	610,518	625,781	641,426	657,461	673,898	690,745	708,014	725,714
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,573,367)	7,473,925	12,625,721	14,291,445	14,924,754	15,590,963	16,271,640	16,956,675	17,659,657	18,383,030	19,103,652
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	2,313,762	4,642,525	4,657,525	4,672,525	4,687,525	4,602,525	4,617,525	4,632,525	3,210,337	3,225,337
Pre-Tax Income	(1,573,367)	5,160,163	7,983,196	9,633,921	10,252,229	10,903,439	11,669,115	12,339,150	13,027,132	15,172,693	15,878,314
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,573,367)	5,160,163	7,983,196	9,633,921	10,252,229	10,903,439	11,669,115	12,339,150	13,027,132	15,172,693	15,878,314

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #4
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,573,367)	5,160,163	7,983,196	9,633,921	10,252,229	10,903,439	11,669,115	12,339,150	13,027,132	15,172,693	15,878,314
Non cash charges to operations											
Depreciation & Amortization	0	2,313,762	4,642,525	4,657,525	4,672,525	4,687,525	4,602,525	4,617,525	4,632,525	3,210,337	3,225,337
	(1,573,367)	7,473,925	12,625,721	14,291,445	14,924,754	15,590,963	16,271,640	16,956,675	17,659,657	18,383,030	19,103,652
Changes in non-cash working capital balances											
Accounts Receivable	0	1,627,272	161,754	123,226	34,411	35,060	35,720	36,394	37,081	37,781	38,495
Inventories	0	2,133,484	178,296	126,166	26,261	26,228	26,631	27,241	27,595	27,910	28,127
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,154,862)	(105,198)	(76,900)	(14,211)	(13,741)	(14,086)	(14,811)	(15,051)	(15,211)	(15,184)
	0	2,605,894	234,852	172,493	46,461	47,546	48,266	48,825	49,625	50,480	51,438
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	71,430,769	6,669,231	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Capitalized Fees & Interest	(1,461,460)	(46,420)	0	0	0	0	0	0	0	0	0
	70,069,309	6,622,811	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Financing Activities											
Long Term Debt Advances	(13,745,323)	13,745,323	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	85,388,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	11,990,544	12,090,869	13,818,953	14,578,293	15,243,417	15,923,373	16,607,850	17,310,031	18,032,550	18,752,214
Cash (Indebtedness), Beginning of Year	0	0	11,990,544	24,081,413	37,900,366	52,478,658	67,722,076	83,645,449	100,253,300	117,563,331	135,595,881
Cash (Bank Indebtedness), End of Year	0	11,990,544	24,081,413	37,900,366	52,478,658	67,722,076	83,645,449	100,253,300	117,563,331	135,595,881	154,348,095

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	85,388,000										
Annual Cash Flows	0	11,990,544	12,090,869	13,818,953	14,578,293	15,243,417	15,923,373	16,607,850	17,310,031	18,032,550	18,752,214
Equity & Cash Flows used for IRR & NPV Calcs	(85,388,000)	11,990,544	12,090,869	13,818,953	14,578,293	15,243,417	15,923,373	16,607,850	17,310,031	18,032,550	18,752,214
Internal Rate of Return (IRR)	**11.4%**										
Net Present Value, 8% discount rate	**$13,818,000**										
Net Present Value, 15% discount rate	**($10,671,000)**										

Financial Forecast for Site #5 – 40 MMGPY Lignite-Fired Plant

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #5
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	35,752,381	42,000,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.4300	$2.4543	$2.4788	$2.5036	$2.5287	$2.5540	$2.5795	$2.6053	$2.6313	$2.6577	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Grain Usage (bu/year)	13,108,853	15,015,595	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
		10.7									
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	112,923	135,140	141,897	141,897	141,897	141,897	141,897	141,897	141,897	141,897	
DDGS Price, FOB ($/ton)	$96.485	$97.450	$98.425	$99.409	$100.403	$101.407	$102.421	$103.445	$104.480	$105.525	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$39.309	$39.702	$40.099	$40.500	$40.905	$41.314	$41.727	$42.144	$42.566	$42.991	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	112,622	132,302	138,918	138,918	138,918	138,918	138,918	138,918	138,918	138,918	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	28.001	32.073	33.677	33.677	33.677	33.677	33.677	33.677	33.677	33.677	
Electricity Price ($/kWh)	$0.0040	$0.0041	$0.0042	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	2.00%
Natural Gas Use (MMBTU/bu)	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	
Annual Natural Gas Use (MMBTU/year)	52,501	60,137	63,144	63,144	63,144	63,144	63,144	63,144	63,144	63,144	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	155,471	178,085	186,989	186,989	186,989	186,989	186,989	186,989	186,989	186,989	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	31,094	35,617	37,398	37,398	37,398	37,398	37,398	37,398	37,398	37,398	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #5
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,666,030	1,908,362	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	114,855	128,500	128,500	128,500	128,500	128,500	128,500	128,500	128,500	128,500	
Lignite Cost, at mine ($/ton)	$11.0000	$11.2200	$11.4444	$11.6733	$11.9068	$12.1449	$12.3878	$12.6355	$12.8883	$13.1460	2.00%
Lignite Transportation Cost ($/ton)	$6.0000	$6.0900	$6.1814	$6.2741	$6.3682	$6.4637	$6.5607	$6.6591	$6.7590	$6.8603	1.50%
Lignite Cost, delivered ($/ton)	$17.0000	$17.3100	$17.6258	$17.9474	$18.2749	$18.6086	$18.9484	$19.2946	$19.6472	$20.0064	
Lime and Limestone Use (tons/year)	28,602	32,000	32,000	32,000	32,000	32,000	32,000	32,000	32,000	32,000	
Lime and Limestone Cost ($/ton)	$23.0000	$23.2300	$23.4623	$23.6969	$23.9339	$24.1732	$24.4150	$24.6591	$24.9057	$25.1548	1.00%
Ammonia Use for SCR (tons/year)	447	500	500	500	500	500	500	500	500	500	
Ammonia Cost ($/tons)	$340.00	$343.4000	$346.8340	$350.3023	$353.8054	$357.3434	$360.9169	$364.5260	$368.1713	$371.8530	1.00%
Boiler Ash Produced (tons/year)	26,814	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	
Boiler Ash Disposal Cost ($/ton)	$8.0000	$8.1600	$8.3232	$8.4897	$8.6595	$8.8326	$9.0093	$9.1895	$9.3733	$9.5607	2.00%
Number of Employees	51	51	51	51	51	51	51	51	51	51	
Average Salary Including Benefits	$53,325	$54,659	$56,025	$57,426	$58,861	$60,333	$61,841	$63,387	$64,972	$66,596	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #5
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$45,000,000
Unit Train Rail Improvements	$1,300,000
Additional Grain Handling and Storage	$1,000,000
Cogeneration System	$26,300,000
Total Engineering and Construction Cost	$73,600,000
Development Costs	
Inventory - Grain	$910,000
Inventory - Lignite/Chemicals/Denaturant	$365,000
Inventory - Ethanol & DDGS	$941,000
Inventory - Spare Parts	$750,000
Startup Costs	$1,000,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$950,000
Well & Process Water Treatment	$600,000
Site Development Costs	$1,500,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,100,000
Capitalized Fees and Interest	$1,900,000
Contingency	$1,000,000
Total Development Costs	$11,816,000
Total Estimated Project Cost	$85,416,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Credit	No
CCC Bioenergy Program	No

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Working Capital at Startup:		
Cash at Startup	$6,755,059	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,483,000	(50% of the value of inventory at startup)
Total Capital at Startup	$8,238,059	
Capital/gallon of capacity	$0.206	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$85,416,000	100.00%
Placement Fees	$854,160	1.000%
Preferred Shares	$0	0.000%
Common Shares	$85,416,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #5
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	11,667,705	23,366,224	36,787,892	50,962,942	65,797,070	81,305,017	97,491,211	114,373,263	131,971,417	150,282,720
Accounts Receivable - Trade	0	1,627,272	1,789,026	1,912,253	1,946,664	1,981,723	2,017,444	2,053,838	2,090,919	2,128,700	2,167,194
Inventories											
Feedstock	0	992,868	1,052,936	1,116,639	1,127,805	1,139,084	1,150,474	1,161,979	1,173,599	1,185,335	1,197,188
Chemicals, Enzymes & Yeast	0	152,730	154,257	155,800	157,358	158,932	160,521	162,126	163,747	165,385	167,039
Denaturant	0	54,525	55,615	56,727	57,862	59,019	60,200	61,404	62,632	63,884	65,162
Finished Product Inventory	0	941,238	1,057,915	1,117,858	1,130,395	1,142,752	1,155,364	1,168,433	1,181,704	1,195,134	1,208,625
Spare Parts	0	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000	750,000
Total Inventories	0	2,141,360	2,320,724	2,447,024	2,473,421	2,499,787	2,526,558	2,553,942	2,581,682	2,609,738	2,638,014
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	15,436,337	27,475,974	41,147,169	55,383,027	70,278,580	85,849,019	102,098,991	119,045,863	136,709,854	155,087,928
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	71,430,769	78,100,000	78,400,000	78,700,000	79,000,000	79,300,000	79,600,000	79,900,000	80,200,000	80,500,000	80,800,000
Less Accumulated Depreciation & Amortizati	0	2,313,733	7,107,147	11,915,561	16,738,975	21,577,389	26,330,802	31,099,216	35,882,630	39,243,857	42,620,083
Net Property, Plant & Equipment	71,430,769	75,786,267	71,292,853	66,784,439	62,261,025	57,722,611	53,269,198	48,800,784	44,317,370	41,256,143	38,179,917
Capitalized Fees & Interest	(1,462,864)	(1,509,481)	(1,358,533)	(1,207,585)	(1,056,636)	(905,688)	(754,740)	(603,792)	(452,844)	(301,896)	(150,948)
Total Assets	70,067,905	89,813,124	97,510,294	106,824,023	116,687,415	127,195,503	138,463,476	150,395,982	163,010,389	177,764,101	193,216,897
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,154,862	1,260,061	1,336,961	1,351,171	1,364,913	1,378,999	1,393,809	1,408,860	1,424,071	1,439,255
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,154,862	1,260,061	1,336,961	1,351,171	1,364,913	1,378,999	1,393,809	1,408,860	1,424,071	1,439,255
Long Term Debt (excluding current maturities)	(13,774,728)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturitie	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(13,774,728)	1,154,862	1,260,061	1,336,961	1,351,171	1,364,913	1,378,999	1,393,809	1,408,860	1,424,071	1,439,255
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000	85,416,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,573,367)	3,242,261	10,834,233	20,071,063	29,920,244	40,414,590	51,668,478	63,586,173	76,185,529	90,924,031	106,361,642
Total Capital Shares & Equities	83,842,633	88,658,261	96,250,233	105,487,063	115,336,244	125,830,590	137,084,478	149,002,173	161,601,529	176,340,031	191,777,642
Total Liabilities & Equities	70,067,905	89,813,124	97,510,294	106,824,023	116,687,415	127,195,503	138,463,476	150,395,982	163,010,389	177,764,101	193,216,897

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #5
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	41,483,488	49,707,252	53,236,467	54,301,196	55,387,220	56,494,965	57,624,864	58,777,361	59,952,908	61,151,967
DDGS	0	10,677,539	12,908,666	13,692,379	13,832,041	13,973,099	14,115,568	14,259,462	14,404,795	14,551,581	14,699,835
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	52,518,550	63,015,918	67,328,846	68,533,237	69,760,319	71,010,533	72,284,326	73,582,156	74,904,490	76,251,802
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	32,847,380	36,852,774	39,082,367	39,473,191	39,867,923	40,266,602	40,669,268	41,075,961	41,486,720	41,901,587
Chemicals, Enzymes & Yeast	0	2,450,045	2,834,479	3,005,965	3,036,024	3,066,385	3,097,049	3,128,019	3,159,299	3,190,892	3,222,801
Natural Gas or Propane (Statrtup/Backup)	0	224,704	253,179	268,363	274,678	266,469	262,680	272,152	283,518	294,884	301,830
Electricity (Standby Charge)	0	112,002	130,859	140,150	142,953	145,812	148,728	151,703	154,737	157,832	160,988
Denaturants	0	1,166,221	1,362,570	1,459,313	1,488,499	1,518,269	1,548,635	1,579,607	1,611,199	1,643,423	1,676,292
Makeup Water	0	155,471	179,866	190,748	192,655	194,582	196,528	198,493	200,478	202,483	204,507
Wastewater Disposal	0	62,188	71,946	76,299	77,062	77,833	78,611	79,397	80,191	80,993	81,803
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	1,952,527	2,224,335	2,264,909	2,306,236	2,348,329	2,391,204	2,434,875	2,479,358	2,524,666	2,570,817
Lime and Limestone	0	657,844	743,360	750,794	758,302	765,885	773,543	781,279	789,092	796,983	804,952
Ammonia for SCR	0	151,948	171,700	173,417	175,151	176,903	178,672	180,458	182,263	184,086	185,926
Boiler Ash Disposal	0	214,514	244,800	249,696	254,690	259,784	264,979	270,279	275,685	281,198	286,822
Direct Labor & Benefits	0	1,184,300	1,213,908	1,244,255	1,275,362	1,307,246	1,339,927	1,373,425	1,407,761	1,442,955	1,479,028
Total Production Costs	0	41,179,144	46,283,776	48,906,276	49,454,802	49,995,418	50,547,158	51,118,956	51,699,540	52,287,114	52,877,355
Gross Profit	0	11,339,407	16,732,142	18,422,570	19,078,435	19,764,902	20,463,375	21,165,371	21,882,616	22,617,375	23,374,446
Administrative & Operating Expenses											
Maintenance Materials & Services	0	1,349,333	1,494,080	1,516,491	1,539,239	1,562,327	1,585,762	1,609,548	1,633,692	1,658,197	1,683,070
Repairs & Maintenance - Wages & Benefits	0	954,200	978,055	1,002,506	1,027,569	1,053,258	1,079,590	1,106,579	1,134,244	1,162,600	1,191,665
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	214,592	1,072,962	1,172,443	1,136,110	1,096,296	1,052,818	1,005,484	955,884	902,127	843,999	809,406
Admin. Salaries, Wages & Benefits	264,550	581,100	595,628	610,518	625,781	641,426	657,461	673,898	690,745	708,014	725,714
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,573,367)	7,129,362	12,234,438	13,894,295	14,521,647	15,181,812	15,856,353	16,535,161	17,231,822	17,948,780	18,662,890
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	2,313,733	4,642,466	4,657,466	4,672,466	4,687,466	4,602,466	4,617,466	4,632,466	3,210,278	3,225,278
Pre-Tax Income	(1,573,367)	4,815,629	7,591,972	9,236,829	9,849,182	10,494,346	11,253,887	11,917,695	12,599,356	14,738,502	15,437,612
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,573,367)	4,815,629	7,591,972	9,236,829	9,849,182	10,494,346	11,253,887	11,917,695	12,599,356	14,738,502	15,437,612

North Dakota Feasibility Study - Lignite Powered Ethanol Plant, Site #5
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,573,367)	4,815,629	7,591,972	9,236,829	9,849,182	10,494,346	11,253,887	11,917,695	12,599,356	14,738,502	15,437,612
Non cash charges to operations											
Depreciation & Amortization	0	2,313,733	4,642,466	4,657,466	4,672,466	4,687,466	4,602,466	4,617,466	4,632,466	3,210,278	3,225,278
	(1,573,367)	7,129,362	12,234,438	13,894,295	14,521,647	15,181,812	15,856,353	16,535,161	17,231,822	17,948,780	18,662,890
Changes in non-cash working capital balances											
Accounts Receivable	0	1,627,272	161,754	123,226	34,411	35,060	35,720	36,394	37,081	37,781	38,495
Inventories	0	2,141,360	179,364	126,300	26,397	26,366	26,772	27,384	27,740	28,056	28,276
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,154,862)	(105,198)	(76,900)	(14,211)	(13,741)	(14,086)	(14,811)	(15,051)	(15,211)	(15,184)
	0	2,613,770	235,920	172,627	46,597	47,684	48,406	48,967	49,770	50,626	51,587
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	71,430,769	6,669,231	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Capitalized Fees & Interest	(1,462,864)	(46,616)	0	0	0	0	0	0	0	0	0
	70,067,905	6,622,615	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Financing Activities											
Long Term Debt Advances	(13,774,728)	13,774,728	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	85,416,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	11,667,705	11,698,518	13,421,668	14,175,050	14,834,128	15,507,947	16,186,194	16,882,052	17,598,154	18,311,303
Cash (Indebtedness), Beginning of Year	0	0	11,667,705	23,366,224	36,787,892	50,962,942	65,797,070	81,305,017	97,491,211	114,373,263	131,971,417
Cash (Bank Indebtedness), End of Year	0	11,667,705	23,366,224	36,787,892	50,962,942	65,797,070	81,305,017	97,491,211	114,373,263	131,971,417	150,282,720

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	85,416,000										
Annual Cash Flows	0	11,667,705	11,698,518	13,421,668	14,175,050	14,834,128	15,507,947	16,186,194	16,882,052	17,598,154	18,311,303
Equity & Cash Flows used for IRR & NPV Calcs	(85,416,000)	11,667,705	11,698,518	13,421,668	14,175,050	14,834,128	15,507,947	16,186,194	16,882,052	17,598,154	18,311,303
Internal Rate of Return (IRR)	**10.8%**										
Net Present Value, 8% discount rate	**$11,305,000**										
Net Present Value, 15% discount rate	**($12,420,000)**										

APPENDIX C FINANCIAL FORECASTS – NATURAL GAS-FIRED PLANTS

Financial Forecast for Site #1 – 40 MMGPY Natural Gas-Fired Plant

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #1
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	35,752,381	42,000,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.2800	$2.3028	$2.3258	$2.3491	$2.3726	$2.3963	$2.4203	$2.4445	$2.4689	$2.4936	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Grain Usage (bu/year)	13,108,853	15,015,595	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	112,923	135,140	141,897	141,897	141,897	141,897	141,897	141,897	141,897	141,897	
DDGS Price, FOB ($/ton)	$90.529	$91.435	$92.349	$93.273	$94.205	$95.147	$96.099	$97.060	$98.030	$99.011	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	$1.811	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$36.882	$37.251	$37.624	$38.000	$38.380	$38.764	$39.151	$39.543	$39.938	$40.338	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	$0.738	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	112,622	132,302	138,918	138,918	138,918	138,918	138,918	138,918	138,918	138,918	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	28.001	32.073	33.677	33.677	33.677	33.677	33.677	33.677	33.677	33.677	
Electricity Price ($/kWh)	$0.0450	$0.0459	$0.0468	$0.0478	$0.0487	$0.0497	$0.0507	$0.0517	$0.0527	$0.0538	2.00%
Natural Gas Use (MMBTU/bu)	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	
Annual Natural Gas Use (MMBTU/year)	1,330,024	1,523,482	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	155,471	178,085	186,989	186,989	186,989	186,989	186,989	186,989	186,989	186,989	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	31,094	35,617	37,398	37,398	37,398	37,398	37,398	37,398	37,398	37,398	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #1
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,666,030	1,908,362	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lignite Cost, at mine ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Lignite Transportation Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Lignite Cost, delivered ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Lime and Limestone Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lime and Limestone Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Ammonia Use for SCR (tons/year)	0	0	0	0	0	0	0	0	0	0	
Ammonia Cost ($/tons)	$0.00	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Boiler Ash Produced (tons/year)	0	0	0	0	0	0	0	0	0	0	
Boiler Ash Disposal Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Number of Employees	36	36	36	36	36	36	36	36	36	36	
Average Salary Including Benefits	$54,997	$56,372	$57,781	$59,226	$60,707	$62,224	$63,780	$65,374	$67,009	$68,684	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #1
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$45,000,000
Unit Train Rail Improvements	$0
Additional Grain Handling and Storage	$0
Cogeneration System	$3,000,000
Total Engineering and Construction Cost	$48,000,000
Development Costs	
Inventory - Grain	$854,000
Inventory - Lignite/Chemicals/Denaturant	$207,000
Inventory - Ethanol & DDGS	$975,000
Inventory - Spare Parts	$450,000
Startup Costs	$750,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$950,000
Well & Process Water Treatment	$600,000
Site Development Costs	$1,500,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,100,000
Capitalized Fees and Interest	$1,900,000
Contingency	$1,000,000
Total Development Costs	$11,086,000
Total Estimated Project Cost	$59,086,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment		Other Incentive Payments	
Producer payment, $/gal	$0.0400	Small Producer Tax Credi	No
Annual payment cap	$400,000	CCC Bioenergy Program	No
Incentive duration, years	10		

Working Capital at Startup:		
Cash at Startup	$5,902,859	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,243,000	(50% of the value of inventory at startup)
Total Capital at Startup	$7,145,859	
Capital/gallon of capacity	$0.179	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment			Grants
Total Equity Amount	$59,086,000	100.00%	Amount
Placement Fees	$590,860	1.000%	$0
Preferred Shares	$0	0.000%	0.00%
Common Shares	$59,086,000	100.000%	

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #1
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	10,500,587	21,441,490	33,800,824	46,809,110	60,727,740	75,473,042	90,730,957	106,467,300	122,701,166	139,544,126
Accounts Receivable - Trade	0	1,606,405	1,766,260	1,888,104	1,922,269	1,957,079	1,992,549	2,028,689	2,065,513	2,103,036	2,141,269
Inventories											
Feedstock	0	931,580	987,940	1,047,711	1,058,188	1,068,770	1,079,457	1,090,252	1,101,154	1,112,166	1,123,288
Chemicals, Enzymes & Yeast	0	152,730	154,257	155,800	157,358	158,932	160,521	162,126	163,747	165,385	167,039
Denaturant	0	54,525	55,615	56,727	57,862	59,019	60,200	61,404	62,632	63,884	65,162
Finished Product Inventory	0	974,860	1,096,750	1,162,838	1,177,639	1,184,165	1,193,387	1,210,426	1,228,702	1,247,120	1,263,123
Spare Parts	0	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Total Inventories	0	2,113,694	2,294,562	2,423,076	2,451,047	2,470,885	2,493,565	2,524,207	2,556,235	2,588,555	2,618,611
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	14,220,686	25,502,312	38,112,004	51,182,426	65,155,705	79,959,155	95,283,853	111,089,048	127,392,757	144,304,006
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	47,800,000	52,200,000	52,300,000	52,400,000	52,500,000	52,600,000	52,700,000	52,800,000	52,900,000	53,000,000	53,100,000
Less Accumulated Depreciation & Amortiza	0	1,559,010	4,792,349	8,030,688	11,274,026	14,522,365	17,675,704	20,834,043	23,997,382	26,208,533	28,424,684
Net Property, Plant & Equipment	47,800,000	50,640,990	47,507,651	44,369,312	41,225,974	38,077,635	35,024,296	31,965,957	28,902,618	26,791,467	24,675,316
Capitalized Fees & Interest	(1,061,598)	(1,103,188)	(992,869)	(882,550)	(772,231)	(661,913)	(551,594)	(441,275)	(330,956)	(220,638)	(110,319)
Total Assets	46,838,402	63,858,488	72,117,095	81,698,767	91,736,168	102,671,427	114,531,857	126,908,535	139,760,710	154,063,587	168,969,003
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,395,996	1,516,578	1,609,463	1,630,801	1,636,541	1,647,254	1,672,539	1,700,058	1,727,757	1,750,840
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,395,996	1,516,578	1,609,463	1,630,801	1,636,541	1,647,254	1,672,539	1,700,058	1,727,757	1,750,840
Long Term Debt (excluding current maturities	(10,760,723)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturiti	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(10,760,723)	1,395,996	1,516,578	1,609,463	1,630,801	1,636,541	1,647,254	1,672,539	1,700,058	1,727,757	1,750,840
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000	59,086,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,486,875)	3,376,493	11,514,516	21,003,304	31,019,367	41,948,885	53,798,603	66,149,997	78,974,652	93,249,829	108,132,163
Total Capital Shares & Equities	57,599,125	62,462,493	70,600,516	80,089,304	90,105,367	101,034,885	112,884,603	125,235,997	138,060,652	152,335,829	167,218,163
Total Liabilities & Equities	46,838,402	63,858,488	72,117,095	81,698,767	91,736,168	102,671,427	114,531,857	126,908,535	139,760,710	154,063,587	168,969,003

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #1
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	41,483,488	49,707,252	53,236,467	54,301,196	55,387,220	56,494,965	57,624,864	58,777,361	59,952,908	61,151,967
DDGS	0	10,018,431	12,111,835	12,847,170	12,978,211	13,110,562	13,244,237	13,379,249	13,515,610	13,653,336	13,792,438
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	51,859,443	62,219,087	66,483,637	67,679,407	68,897,782	70,139,202	71,404,112	72,692,971	74,006,244	75,344,405
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	30,819,764	34,577,912	36,669,875	37,036,574	37,406,940	37,781,009	38,158,819	38,540,407	38,925,812	39,315,070
Chemicals, Enzymes & Yeast	0	2,450,045	2,834,479	3,005,965	3,036,024	3,066,385	3,097,049	3,128,019	3,159,299	3,190,892	3,222,801
Natural Gas or Propane (Statrtup/Backup)	0	5,692,504	6,413,860	6,798,540	6,958,505	6,750,550	6,654,570	6,894,519	7,182,457	7,470,395	7,646,357
Electricity (Standby Charge)	0	1,260,023	1,472,165	1,576,689	1,608,222	1,640,387	1,673,195	1,706,659	1,740,792	1,775,608	1,811,120
Denaturants	0	1,166,221	1,362,570	1,459,313	1,488,499	1,518,269	1,548,635	1,579,607	1,611,199	1,643,423	1,676,292
Makeup Water	0	155,471	179,866	190,748	192,655	194,582	196,528	198,493	200,478	202,483	204,507
Wastewater Disposal	0	62,188	71,946	76,299	77,062	77,833	78,611	79,397	80,191	80,993	81,803
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	0	0	0	0	0	0	0	0	0	0
Lime and Limestone	0	0	0	0	0	0	0	0	0	0	0
Ammonia for SCR	0	0	0	0	0	0	0	0	0	0	0
Boiler Ash Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	0	1,043,900	1,069,998	1,096,747	1,124,166	1,152,270	1,181,077	1,210,604	1,240,869	1,271,891	1,303,688
Total Production Costs	0	42,650,115	47,982,796	50,874,175	51,521,709	51,807,215	52,210,673	52,956,117	53,755,693	54,561,496	55,261,638
Gross Profit	0	9,209,328	14,236,291	15,609,462	16,157,699	17,090,567	17,928,529	18,447,996	18,937,279	19,444,748	20,082,767
Administrative & Operating Expenses											
Maintenance Materials & Services	0	880,000	974,400	989,016	1,003,851	1,018,909	1,034,193	1,049,706	1,065,451	1,081,433	1,097,654
Repairs & Maintenance - Wages & Benefits	0	386,100	395,753	405,646	415,787	426,182	436,837	447,758	458,952	470,425	482,186
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	143,700	718,500	783,948	757,604	728,892	697,691	663,875	629,104	591,556	551,095	526,309
Admin. Salaries, Wages & Benefits	248,950	549,900	563,648	577,739	592,182	606,987	622,161	637,715	653,658	670,000	686,750
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,486,875)	6,422,378	11,261,044	12,616,807	13,149,083	14,067,538	14,892,738	15,399,414	15,877,676	16,376,010	16,988,166
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	1,559,010	3,123,020	3,128,020	3,133,020	3,138,020	3,043,020	3,048,020	3,053,020	2,100,833	2,105,833
Pre-Tax Income	(1,486,875)	4,863,368	8,138,024	9,488,787	10,016,063	10,929,518	11,849,718	12,351,394	12,824,656	14,275,177	14,882,334
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,486,875)	4,863,368	8,138,024	9,488,787	10,016,063	10,929,518	11,849,718	12,351,394	12,824,656	14,275,177	14,882,334

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #1
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,486,875)	4,863,368	8,138,024	9,488,787	10,016,063	10,929,518	11,849,718	12,351,394	12,824,656	14,275,177	14,882,334
Non cash charges to operations											
Depreciation & Amortization	0	1,559,010	3,123,020	3,128,020	3,133,020	3,138,020	3,043,020	3,048,020	3,053,020	2,100,833	2,105,833
	(1,486,875)	6,422,378	11,261,044	12,616,807	13,149,083	14,067,538	14,892,738	15,399,414	15,877,676	16,376,010	16,988,166
Changes in non-cash working capital balances											
Accounts Receivable	0	1,606,405	159,855	121,844	34,165	34,811	35,469	36,140	36,825	37,522	38,233
Inventories	0	2,113,694	180,868	128,514	27,970	19,839	22,679	30,642	32,028	32,320	30,056
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,395,996)	(120,583)	(92,885)	(21,338)	(5,741)	(10,713)	(25,285)	(27,519)	(27,699)	(23,083)
	0	2,324,103	220,141	157,474	40,797	48,909	47,436	41,498	41,333	42,143	45,207
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	47,800,000	4,400,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	(1,061,598)	(41,589)	0	0	0	0	0	0	0	0	0
	46,838,402	4,358,411	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Long Term Debt Advances	(10,760,723)	10,760,723	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	59,086,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	10,500,587	10,940,903	12,359,334	13,008,286	13,918,630	14,745,302	15,257,916	15,736,343	16,233,867	16,842,959
Cash (Indebtedness), Beginning of Year	0	0	10,500,587	21,441,490	33,800,824	46,809,110	60,727,740	75,473,042	90,730,957	106,467,300	122,701,166
Cash (Bank Indebtedness), End of Year	0	10,500,587	21,441,490	33,800,824	46,809,110	60,727,740	75,473,042	90,730,957	106,467,300	122,701,166	139,544,126

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	59,086,000										
Annual Cash Flows	0	10,500,587	10,940,903	12,359,334	13,008,286	13,918,630	14,745,302	15,257,916	15,736,343	16,233,867	16,842,959
Equity & Cash Flows used for IRR & NPV Calcs	(59,086,000)	10,500,587	10,940,903	12,359,334	13,008,286	13,918,630	14,745,302	15,257,916	15,736,343	16,233,867	16,842,959
Internal Rate of Return (IRR)	**17.7%**										
Net Present Value, 8% discount rate	**$29,150,000**										
Net Present Value, 15% discount rate	**$5,943,000**										

Financial Forecast for Site #2 – 30 MMGPY Natural Gas-Fired Plant

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #2
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	30,000,000
Anhydrous Ethanol Production (gal/year)	28,636,884
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	26,814,286	31,500,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	33,075,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.1500	$2.1715	$2.1932	$2.2151	$2.2373	$2.2597	$2.2823	$2.3051	$2.3281	$2.3514	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0700	$0.0711	$0.0721	$0.0732	$0.0743	$0.0754	$0.0765	$0.0777	$0.0789	$0.0800	1.50%
Grain Usage (bu/year)	9,831,639	11,261,696	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	11,824,781	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	84,693	101,355	106,423	106,423	106,423	106,423	106,423	106,423	106,423	106,423	
DDGS Price, FOB ($/ton)	$85.368	$86.221	$87.084	$87.954	$88.834	$89.722	$90.619	$91.526	$92.441	$93.365	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	$1.707	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$34.779	$35.127	$35.478	$35.833	$36.192	$36.554	$36.919	$37.288	$37.661	$38.038	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	$0.696	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	84,467	99,227	104,188	104,188	104,188	104,188	104,188	104,188	104,188	104,188	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	21.000	24.055	25.258	25.258	25.258	25.258	25.258	25.258	25.258	25.258	
Electricity Price ($/kWh)	$0.0450	$0.0459	$0.0468	$0.0478	$0.0487	$0.0497	$0.0507	$0.0517	$0.0527	$0.0538	2.00%
Natural Gas Use (MMBTU/bu)	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	
Annual Natural Gas Use (MMBTU/year)	997,518	1,142,612	1,199,742	1,199,742	1,199,742	1,199,742	1,199,742	1,199,742	1,199,742	1,199,742	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	116,603	133,564	140,242	140,242	140,242	140,242	140,242	140,242	140,242	140,242	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	23,321	26,713	28,048	28,048	28,048	28,048	28,048	28,048	28,048	28,048	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #2
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,249,523	1,431,271	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	1,502,835	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lignite Cost, at mine ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Lignite Transportation Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Lignite Cost, delivered ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Lime and Limestone Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lime and Limestone Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Ammonia Use for SCR (tons/year)	0	0	0	0	0	0	0	0	0	0	
Ammonia Cost ($/tons)	$0.00	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Boiler Ash Produced (tons/year)	0	0	0	0	0	0	0	0	0	0	
Boiler Ash Disposal Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Number of Employees	34	34	34	34	34	34	34	34	34	34	
Average Salary Including Benefits	$55,403	$56,788	$58,208	$59,663	$61,154	$62,683	$64,250	$65,857	$67,503	$69,191	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #2
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$34,500,000
Unit Train Rail Improvements	$0
Additional Grain Handling and Storage	$0
Cogeneration System	$2,500,000
Total Engineering and Construction Cost	$37,000,000
Development Costs	
Inventory - Grain	$624,000
Inventory - Lignite/Chemicals/Denaturant	$155,000
Inventory - Ethanol & DDGS	$721,000
Inventory - Spare Parts	$450,000
Startup Costs	$750,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$850,000
Well & Process Water Treatment	$500,000
Site Development Costs	$1,300,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,000,000
Capitalized Fees and Interest	$1,500,000
Contingency	$800,000
Total Development Costs	$9,450,000
Total Estimated Project Cost	$46,450,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment		Other Incentive Payments	
Producer payment, $/gal	$0.0400	Small Producer Tax Credit	No
Annual payment cap	$400,000	CCC Bioenergy Program	No
Incentive duration, years	10		

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Working Capital at Startup:		
Cash at Startup	$4,514,158	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$975,000	(50% of the value of inventory at startup)
Total Capital at Startup	$5,489,158	
Capital/gallon of capacity	$0.183	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$46,450,000	100.00%
Placement Fees	$464,500	1.000%
Preferred Shares	$0	0.000%
Common Shares	$46,450,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #2
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	7,828,708	15,753,790	24,736,472	34,190,404	44,312,855	55,040,780	66,137,891	77,578,221	89,375,762	101,613,356
Accounts Receivable - Trade	0	1,191,240	1,309,896	1,400,381	1,425,845	1,451,791	1,478,230	1,505,170	1,532,622	1,560,595	1,589,100
Inventories											
Feedstock	0	680,298	721,569	765,344	773,119	780,974	788,909	796,926	805,024	813,206	821,471
Chemicals, Enzymes & Yeast	0	114,548	115,693	116,850	118,018	119,199	120,391	121,595	122,810	124,039	125,279
Denaturant	0	40,893	41,711	42,546	43,396	44,264	45,150	46,053	46,974	47,913	48,871
Finished Product Inventory	0	721,007	810,914	859,734	870,868	875,798	882,754	895,576	909,330	923,194	935,250
Spare Parts	0	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Total Inventories	0	1,556,747	1,689,887	1,784,474	1,805,402	1,820,236	1,837,204	1,860,149	1,884,138	1,908,351	1,930,872
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	10,576,694	18,753,574	27,921,327	37,421,650	47,584,882	58,356,214	69,503,210	80,994,981	92,844,709	105,133,328
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	37,276,923	40,800,000	40,900,000	41,000,000	41,100,000	41,200,000	41,300,000	41,400,000	41,500,000	41,600,000	41,700,000
Less Accumulated Depreciation & Amortiza	0	1,226,922	3,772,650	6,323,378	8,879,106	11,439,834	13,905,562	16,376,290	18,852,018	20,589,309	22,331,599
Net Property, Plant & Equipment	37,276,923	39,573,078	37,127,350	34,676,622	32,220,894	29,760,166	27,394,438	25,023,710	22,647,982	21,010,691	19,368,401
Capitalized Fees & Interest	(836,944)	(868,849)	(781,964)	(695,080)	(608,195)	(521,310)	(434,425)	(347,540)	(260,655)	(173,770)	(86,885)
Total Assets	36,539,979	49,380,923	55,198,959	62,002,870	69,134,350	76,923,738	85,416,227	94,279,380	103,482,308	113,781,630	124,514,843
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,029,121	1,118,048	1,186,658	1,202,579	1,206,803	1,214,757	1,233,641	1,254,202	1,274,899	1,292,135
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,029,121	1,118,048	1,186,658	1,202,579	1,206,803	1,214,757	1,233,641	1,254,202	1,274,899	1,292,135
Long Term Debt (excluding current maturities	(8,454,715)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturiti	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(8,454,715)	1,029,121	1,118,048	1,186,658	1,202,579	1,206,803	1,214,757	1,233,641	1,254,202	1,274,899	1,292,135
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000	46,450,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,455,306)	1,901,802	7,630,912	14,366,211	21,481,771	29,266,935	37,751,470	46,595,739	55,778,106	66,056,731	76,772,708
Total Capital Shares & Equities	44,994,694	48,351,802	54,080,912	60,816,211	67,931,771	75,716,935	84,201,470	93,045,739	102,228,106	112,506,731	123,222,708
Total Liabilities & Equities	36,539,979	49,380,923	55,198,959	62,002,870	69,134,350	76,923,738	85,416,227	94,279,380	103,482,308	113,781,630	124,514,843

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #2
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	31,112,616	37,280,439	39,927,350	40,725,897	41,540,415	42,371,223	43,218,648	44,083,021	44,964,681	45,863,975
DDGS	0	7,085,404	8,565,936	9,085,992	9,178,669	9,272,273	9,366,812	9,462,298	9,558,738	9,656,142	9,754,520
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	38,555,543	46,246,375	49,413,342	50,304,566	51,212,688	52,138,036	53,080,945	54,041,758	55,020,823	56,018,495
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	22,506,538	25,254,917	26,787,040	27,059,174	27,334,093	27,611,827	27,892,404	28,175,853	28,462,205	28,751,489
Chemicals, Enzymes & Yeast	0	1,837,533	2,125,859	2,254,474	2,277,018	2,299,789	2,322,786	2,346,014	2,369,474	2,393,169	2,417,101
Natural Gas or Propane (Statrtup/Backup)	0	4,269,378	4,810,395	5,098,905	5,218,879	5,062,912	4,990,928	5,170,889	5,386,843	5,602,796	5,734,768
Electricity (Standby Charge)	0	945,017	1,104,124	1,182,516	1,206,167	1,230,290	1,254,896	1,279,994	1,305,594	1,331,706	1,358,340
Denaturants	0	874,666	1,021,928	1,094,485	1,116,374	1,138,702	1,161,476	1,184,705	1,208,400	1,232,568	1,257,219
Makeup Water	0	116,603	134,899	143,061	144,491	145,936	147,396	148,870	150,358	151,862	153,381
Wastewater Disposal	0	46,641	53,960	57,224	57,797	58,375	58,958	59,548	60,143	60,745	61,352
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	0	0	0	0	0	0	0	0	0	0
Lime and Limestone	0	0	0	0	0	0	0	0	0	0	0
Ammonia for SCR	0	0	0	0	0	0	0	0	0	0	0
Boiler Ash Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	0	947,700	971,393	995,677	1,020,569	1,046,083	1,072,236	1,099,041	1,126,517	1,154,680	1,183,547
Total Production Costs	0	31,544,077	35,477,474	37,613,382	38,100,469	38,316,181	38,620,503	39,181,465	39,783,183	40,389,731	40,917,197
Gross Profit	0	7,011,467	10,768,901	11,799,961	12,204,097	12,896,507	13,517,533	13,899,480	14,258,576	14,631,092	15,101,298
Administrative & Operating Expenses											
Maintenance Materials & Services	0	678,333	751,100	762,367	773,802	785,409	797,190	809,148	821,285	833,605	846,109
Repairs & Maintenance - Wages & Benefits	0	386,100	395,753	405,646	415,787	426,182	436,837	447,758	458,952	470,425	482,186
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	112,131	560,654	612,949	592,417	570,020	545,662	519,242	492,447	463,485	432,247	413,170
Admin. Salaries, Wages & Benefits	248,950	549,900	563,648	577,739	592,182	606,987	622,161	637,715	653,658	670,000	686,750
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,455,306)	4,584,030	8,187,953	9,199,143	9,584,403	10,259,008	10,863,378	11,228,112	11,571,210	11,929,030	12,371,383
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	1,226,922	2,458,843	2,463,843	2,468,843	2,473,843	2,378,843	2,383,843	2,388,843	1,650,406	1,655,406
Pre-Tax Income	(1,455,306)	3,357,108	5,729,110	6,735,300	7,115,560	7,785,164	8,484,535	8,844,269	9,182,367	10,278,625	10,715,977
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,455,306)	3,357,108	5,729,110	6,735,300	7,115,560	7,785,164	8,484,535	8,844,269	9,182,367	10,278,625	10,715,977

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #2
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,455,306)	3,357,108	5,729,110	6,735,300	7,115,560	7,785,164	8,484,535	8,844,269	9,182,367	10,278,625	10,715,977
Non cash charges to operations											
Depreciation & Amortization	0	1,226,922	2,458,843	2,463,843	2,468,843	2,473,843	2,378,843	2,383,843	2,388,843	1,650,406	1,655,406
	(1,455,306)	4,584,030	8,187,953	9,199,143	9,584,403	10,259,008	10,863,378	11,228,112	11,571,210	11,929,030	12,371,383
Changes in non-cash working capital balances											
Accounts Receivable	0	1,191,240	118,657	90,485	25,464	25,946	26,439	26,940	27,452	27,973	28,505
Inventories	0	1,556,747	133,140	94,587	20,928	14,833	16,968	22,945	23,989	24,213	22,520
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,029,121)	(88,926)	(68,611)	(15,921)	(4,224)	(7,954)	(18,884)	(20,561)	(20,697)	(17,236)
	0	1,718,865	162,871	116,461	30,471	36,556	35,453	31,001	30,880	31,489	33,789
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	37,276,923	3,523,077	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	(836,944)	(31,905)	0	0	0	0	0	0	0	0	0
	36,539,979	3,491,172	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Long Term Debt Advances	(8,454,715)	8,454,715	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	46,450,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	7,828,708	7,925,082	8,982,682	9,453,932	10,122,452	10,727,925	11,097,111	11,440,330	11,797,541	12,237,594
Cash (Indebtedness), Beginning of Year	0	0	7,828,708	15,753,790	24,736,472	34,190,404	44,312,855	55,040,780	66,137,891	77,578,221	89,375,762
Cash (Bank Indebtedness), End of Year	0	7,828,708	15,753,790	24,736,472	34,190,404	44,312,855	55,040,780	66,137,891	77,578,221	89,375,762	101,613,356

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	46,450,000										
Annual Cash Flows	0	7,828,708	7,925,082	8,982,682	9,453,932	10,122,452	10,727,925	11,097,111	11,440,330	11,797,541	12,237,594
Equity & Cash Flows used for IRR & NPV Calcs	(46,450,000)	7,828,708	7,925,082	8,982,682	9,453,932	10,122,452	10,727,925	11,097,111	11,440,330	11,797,541	12,237,594
Internal Rate of Return (IRR)	**15.8%**										
Net Present Value, 8% discount rate	**$18,100,000**										
Net Present Value, 15% discount rate	**$1,411,000**										

Financial Forecast for Site #3 – 10 MMGPY Natural Gas-Fired Plant

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #3
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	10,000,000
Anhydrous Ethanol Production (gal/year)	9,545,628
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	2.2000	
Denatured Ethanol Sold (gal/year)	8,938,095	10,500,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	11,025,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$1.8400	$1.8584	$1.8770	$1.8958	$1.9147	$1.9339	$1.9532	$1.9727	$1.9925	$2.0124	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0700	$0.0711	$0.0721	$0.0732	$0.0743	$0.0754	$0.0765	$0.0777	$0.0789	$0.0800	1.50%
Grain Usage (bu/year)	3,977,345	4,555,868	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	4,783,661	
Grain Test Weight (lb/bu)	48.000	48.000	48.000	48.000	48.000	48.000	48.000	48.000	48.000	48.000	
DDGS Yield (lb/bu)	19.000	19.000	19.000	19.000	19.000	19.000	19.000	19.000	19.000	19.000	
DDGS Sold (ton/year)	36,165	43,281	45,445	45,445	45,445	45,445	45,445	45,445	45,445	45,445	
DDGS Price, FOB ($/ton)	$85.235	$86.088	$86.949	$87.818	$88.696	$89.583	$90.479	$91.384	$92.298	$93.221	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	$1.705	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$34.725	$35.073	$35.423	$35.778	$36.135	$36.497	$36.862	$37.230	$37.603	$37.979	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	$0.695	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	28,156	33,076	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	1.509	1.509	1.509	1.509	1.509	1.509	1.509	1.509	1.509	1.509	
Annual Electricity Use (million kWh/year)	6.000	6.873	7.216	7.216	7.216	7.216	7.216	7.216	7.216	7.216	
Electricity Price ($/kWh)	$0.0450	$0.0459	$0.0468	$0.0478	$0.0487	$0.0497	$0.0507	$0.0517	$0.0527	$0.0538	2.00%
Natural Gas Use (MMBTU/bu)	0.0836	0.0836	0.0836	0.0836	0.0836	0.0836	0.0836	0.0836	0.0836	0.0836	
Annual Natural Gas Use (MMBTU/year)	332,506	380,871	399,914	399,914	399,914	399,914	399,914	399,914	399,914	399,914	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	
Annual Fresh Water Use (1000 gal/year)	40,433	46,314	48,629	48,629	48,629	48,629	48,629	48,629	48,629	48,629	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	8,087	9,263	9,726	9,726	9,726	9,726	9,726	9,726	9,726	9,726	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #3
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	416,508	477,090	500,945	500,945	500,945	500,945	500,945	500,945	500,945	500,945	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0900	$0.0909	$0.0918	$0.0927	$0.0937	$0.0946	$0.0955	$0.0965	$0.0975	$0.0984	1.00%
Lignite Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lignite Cost, at mine ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Lignite Transportation Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Lignite Cost, delivered ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Lime and Limestone Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lime and Limestone Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Ammonia Use for SCR (tons/year)	0	0	0	0	0	0	0	0	0	0	
Ammonia Cost ($/tons)	$0.00	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Boiler Ash Produced (tons/year)	0	0	0	0	0	0	0	0	0	0	
Boiler Ash Disposal Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Number of Employees	20	20	20	20	20	20	20	20	20	20	
Average Salary Including Benefits	$57,980	$59,430	$60,915	$62,438	$63,999	$65,599	$67,239	$68,920	$70,643	$72,409	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #3
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$15,000,000
Unit Train Rail Improvements	$0
Additional Grain Handling and Storage	$0
Cogeneration System	$1,100,000
Total Engineering and Construction Cost	$16,100,000
Development Costs	
Inventory - Grain	$217,000
Inventory - Lignite/Chemicals/Denaturant	$63,000
Inventory - Ethanol & DDGS	$257,000
Inventory - Spare Parts	$300,000
Startup Costs	$600,000
Land	$50,000
Administration Building & Furnishing	$200,000
Rail Improvements	$600,000
Well & Process Water Treatment	$300,000
Site Development Costs	$700,000
Rolling Stock and Shop Equipment	$300,000
Organizational Costs	$600,000
Capitalized Fees and Interest	$750,000
Contingency	$500,000
Total Development Costs	$5,437,000
Total Estimated Project Cost	$21,537,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Credit	Yes
CCC Bioenergy Program	No

Working Capital at Startup:		
Cash at Startup	$1,744,906	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$418,500	(50% of the value of inventory at startup)
Total Capital at Startup	$2,163,406	
Capital/gallon of capacity	$0.216	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$21,537,000	100.00%
Placement Fees	$215,370	1.000%
Preferred Shares	$0	0.000%
Common Shares	$21,537,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #3
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	3,421,424	6,766,172	10,518,232	14,416,542	18,525,315	22,823,403	27,231,201	31,739,886	36,353,959	41,099,228
Accounts Receivable - Trade	0	417,948	459,399	490,943	499,677	508,575	517,639	526,873	536,280	545,863	555,626
Inventories											
Feedstock	0	236,781	251,152	266,395	269,108	271,850	274,619	277,417	280,243	283,099	285,983
Chemicals, Enzymes & Yeast	0	49,092	49,583	50,079	50,579	51,085	51,596	52,112	52,633	53,159	53,691
Denaturant	0	13,631	13,904	14,182	14,465	14,755	15,050	15,351	15,658	15,971	16,290
Finished Product Inventory	0	257,171	288,688	305,841	309,837	311,770	314,385	318,959	323,850	328,783	333,120
Spare Parts	0	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Total Inventories	0	556,675	603,326	636,496	643,990	649,460	655,649	663,839	672,384	681,012	689,085
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	4,396,046	7,828,897	11,645,671	15,560,210	19,683,350	23,996,691	28,421,912	32,948,549	37,580,834	42,343,939
Land	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	16,823,077	18,500,000	18,550,000	18,600,000	18,650,000	18,700,000	18,750,000	18,800,000	18,850,000	18,900,000	18,950,000
Less Accumulated Depreciation & Amortization	0	569,649	1,750,997	2,934,845	4,121,193	5,310,041	6,428,056	7,548,571	8,671,586	9,465,225	10,261,365
Net Property, Plant & Equipment	16,823,077	17,930,351	16,799,003	15,665,155	14,528,807	13,389,959	12,321,944	11,251,429	10,178,414	9,434,775	8,688,635
Capitalized Fees & Interest	(383,118)	(395,500)	(355,950)	(316,400)	(276,850)	(237,300)	(197,750)	(158,200)	(118,650)	(79,100)	(39,550)
Total Assets	16,489,959	21,980,897	24,321,950	27,044,425	29,862,166	32,886,008	36,170,885	39,565,141	43,058,314	46,986,509	51,043,024
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	358,786	389,844	413,737	419,210	420,786	423,606	430,071	437,097	444,169	450,089
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	358,786	389,844	413,737	419,210	420,786	423,606	430,071	437,097	444,169	450,089
Long Term Debt (excluding current maturities)	(3,681,305)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(3,681,305)	358,786	389,844	413,737	419,210	420,786	423,606	430,071	437,097	444,169	450,089
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000	21,537,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,365,736)	85,111	2,395,106	5,093,688	7,905,956	10,928,222	14,210,279	17,598,070	21,084,217	25,005,340	29,055,936
Total Capital Shares & Equities	20,171,264	21,622,111	23,932,106	26,630,688	29,442,956	32,465,222	35,747,279	39,135,070	42,621,217	46,542,340	50,592,936
Total Liabilities & Equities	16,489,959	21,980,897	24,321,950	27,044,425	29,862,166	32,886,008	36,170,885	39,565,141	43,058,314	46,986,509	51,043,024

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #3
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	10,370,872	12,426,813	13,309,117	13,575,299	13,846,805	14,123,741	14,406,216	14,694,340	14,988,227	15,287,992
DDGS	0	3,020,920	3,652,157	3,873,887	3,913,400	3,953,309	3,993,617	4,034,328	4,075,446	4,116,975	4,158,919
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	893,810	1,050,000	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	14,643,125	17,528,970	18,685,504	18,991,199	19,302,614	19,619,858	19,943,044	20,272,286	20,607,702	20,949,411
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	7,833,510	8,790,319	9,323,833	9,418,796	9,514,735	9,611,659	9,709,580	9,808,506	9,908,450	10,009,420
Chemicals, Enzymes & Yeast	0	787,514	911,082	966,203	975,865	985,624	995,480	1,005,435	1,015,489	1,025,644	1,035,900
Natural Gas or Propane (Statrtup/Backup)	0	1,423,126	1,603,465	1,699,635	1,739,626	1,687,637	1,663,643	1,723,630	1,795,614	1,867,599	1,911,589
Electricity (Standby Charge)	0	270,005	315,464	337,862	344,619	351,511	358,542	365,713	373,027	380,487	388,097
Denaturants	0	291,555	340,643	364,828	372,125	379,567	387,159	394,902	402,800	410,856	419,073
Makeup Water	0	40,433	46,777	49,607	50,103	50,604	51,110	51,621	52,137	52,659	53,185
Wastewater Disposal	0	16,173	18,711	19,843	20,041	20,242	20,444	20,648	20,855	21,063	21,274
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	0	0	0	0	0	0	0	0	0	0
Lime and Limestone	0	0	0	0	0	0	0	0	0	0	0
Ammonia for SCR	0	0	0	0	0	0	0	0	0	0	0
Boiler Ash Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	0	588,900	603,623	618,713	634,181	650,035	666,286	682,943	700,017	717,517	735,455
Total Production Costs	0	11,251,216	12,630,084	13,380,524	13,555,356	13,639,956	13,754,322	13,954,471	14,168,445	14,384,275	14,573,994
Gross Profit	0	3,391,909	4,898,886	5,304,980	5,435,843	5,662,658	5,865,535	5,988,572	6,103,841	6,223,427	6,375,416
Administrative & Operating Expenses											
Maintenance Materials & Services	0	295,167	326,830	331,732	336,708	341,759	346,885	352,089	357,370	362,731	368,172
Repairs & Maintenance - Wages & Benefits	0	201,500	206,538	211,701	216,993	222,418	227,979	233,678	239,520	245,508	251,646
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	50,619	253,096	277,796	268,127	257,586	246,129	233,709	221,591	208,490	194,356	185,632
Admin. Salaries, Wages & Benefits	220,892	369,200	378,430	387,891	397,588	407,528	417,716	428,159	438,863	449,834	461,080
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,365,736)	2,020,496	3,451,793	3,842,880	3,959,065	4,171,565	4,360,521	4,468,756	4,569,612	4,675,213	4,807,185
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	569,649	1,141,798	1,144,298	1,146,798	1,149,298	1,078,465	1,080,965	1,083,465	754,090	756,590
Pre-Tax Income	(1,365,736)	1,450,847	2,309,995	2,698,582	2,812,267	3,022,267	3,282,057	3,387,791	3,486,147	3,921,123	4,050,596
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,365,736)	1,450,847	2,309,995	2,698,582	2,812,267	3,022,267	3,282,057	3,387,791	3,486,147	3,921,123	4,050,596

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #3
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,365,736)	1,450,847	2,309,995	2,698,582	2,812,267	3,022,267	3,282,057	3,387,791	3,486,147	3,921,123	4,050,596
Non cash charges to operations											
Depreciation & Amortization	0	569,649	1,141,798	1,144,298	1,146,798	1,149,298	1,078,465	1,080,965	1,083,465	754,090	756,590
	(1,365,736)	2,020,496	3,451,793	3,842,880	3,959,065	4,171,565	4,360,521	4,468,756	4,569,612	4,675,213	4,807,185
Changes in non-cash working capital balances											
Accounts Receivable	0	417,948	41,452	31,544	8,734	8,898	9,064	9,234	9,407	9,583	9,763
Inventories	0	556,675	46,651	33,170	7,494	5,470	6,189	8,190	8,545	8,628	8,072
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(358,786)	(31,058)	(23,893)	(5,473)	(1,576)	(2,820)	(6,465)	(7,025)	(7,072)	(5,920)
	0	615,836	57,045	40,821	10,755	12,792	12,433	10,958	10,927	11,140	11,916
Investing Activities											
Land Purchase	50,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	16,823,077	1,676,923	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Capitalized Fees & Interest	(383,118)	(12,382)	0	0	0	0	0	0	0	0	0
	16,489,959	1,664,541	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Financing Activities											
Long Term Debt Advances	(3,681,305)	3,681,305	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	21,537,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	3,421,424	3,344,748	3,752,060	3,898,311	4,108,773	4,298,088	4,407,797	4,508,685	4,614,073	4,745,270
Cash (Indebtedness), Beginning of Year	0	0	3,421,424	6,766,172	10,518,232	14,416,542	18,525,315	22,823,403	27,231,201	31,739,886	36,353,959
Cash (Bank Indebtedness), End of Year	0	3,421,424	6,766,172	10,518,232	14,416,542	18,525,315	22,823,403	27,231,201	31,739,886	36,353,959	41,099,228

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	21,537,000										
Annual Cash Flows	0	3,421,424	3,344,748	3,752,060	3,898,311	4,108,773	4,298,088	4,407,797	4,508,685	4,614,073	4,745,270
Equity & Cash Flows used for IRR & NPV Calcs	(21,537,000)	3,421,424	3,344,748	3,752,060	3,898,311	4,108,773	4,298,088	4,407,797	4,508,685	4,614,073	4,745,270
Internal Rate of Return (IRR)	**12.9%**										
Net Present Value, 8% discount rate	**$4,964,000**										
Net Present Value, 15% discount rate	**($1,583,000)**										

Financial Forecast for Site #4 – 40 MMGPY Natural Gas-Fired Plants

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #4
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	35,752,381	42,000,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.4300	$2.4543	$2.4788	$2.5036	$2.5287	$2.5540	$2.5795	$2.6053	$2.6313	$2.6577	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Grain Usage (bu/year)	13,108,853	15,015,595	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	112,923	135,140	141,897	141,897	141,897	141,897	141,897	141,897	141,897	141,897	
DDGS Price, FOB ($/ton)	$96.485	$97.450	$98.425	$99.409	$100.403	$101.407	$102.421	$103.445	$104.480	$105.525	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$39.309	$39.702	$40.099	$40.500	$40.905	$41.314	$41.727	$42.144	$42.566	$42.991	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	112,622	132,302	138,918	138,918	138,918	138,918	138,918	138,918	138,918	138,918	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	28.001	32.073	33.677	33.677	33.677	33.677	33.677	33.677	33.677	33.677	
Electricity Price ($/kWh)	$0.0450	$0.0459	$0.0468	$0.0478	$0.0487	$0.0497	$0.0507	$0.0517	$0.0527	$0.0538	2.00%
Natural Gas Use (MMBTU/bu)	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	
Annual Natural Gas Use (MMBTU/year)	1,330,024	1,523,482	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	155,471	178,085	186,989	186,989	186,989	186,989	186,989	186,989	186,989	186,989	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	31,094	35,617	37,398	37,398	37,398	37,398	37,398	37,398	37,398	37,398	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #4
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,666,030	1,908,362	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lignite Cost, at mine ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Lignite Transportation Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Lignite Cost, delivered ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Lime and Limestone Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lime and Limestone Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Ammonia Use for SCR (tons/year)	0	0	0	0	0	0	0	0	0	0	
Ammonia Cost ($/tons)	$0.00	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Boiler Ash Produced (tons/year)	0	0	0	0	0	0	0	0	0	0	
Boiler Ash Disposal Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Number of Employees	36	36	36	36	36	36	36	36	36	36	
Average Salary Including Benefits	$54,997	$56,372	$57,781	$59,226	$60,707	$62,224	$63,780	$65,374	$67,009	$68,684	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #4
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$45,000,000
Unit Train Rail Improvements	$1,300,000
Additional Grain Handling and Storage	$1,000,000
Cogeneration System	$3,000,000
Total Engineering and Construction Cost	$50,300,000
Development Costs	
Inventory - Grain	$910,000
Inventory - Lignite/Chemicals/Denaturant	$207,000
Inventory - Ethanol & DDGS	$1,021,000
Inventory - Spare Parts	$450,000
Startup Costs	$750,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$950,000
Well & Process Water Treatment	$600,000
Site Development Costs	$1,500,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,100,000
Capitalized Fees and Interest	$1,900,000
Contingency	$1,000,000
Total Development Costs	$11,188,000
Total Estimated Project Cost	$61,488,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Credit	No
CCC Bioenergy Program	No

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Working Capital at Startup:		
Cash at Startup	$5,878,172	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,294,000	(50% of the value of inventory at startup)
Total Capital at Startup	$7,172,172	
Capital/gallon of capacity	$0.179	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$61,488,000	100.00%
Placement Fees	$614,880	1.000%
Preferred Shares	$0	0.000%
Common Shares	$61,488,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #4
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	9,123,647	18,499,484	29,206,286	40,550,823	52,790,689	65,842,157	79,391,114	93,403,326	107,897,846	122,985,357
Accounts Receivable - Trade	0	1,627,272	1,789,026	1,912,253	1,946,664	1,981,723	2,017,444	2,053,838	2,090,919	2,128,700	2,167,194
Inventories											
Feedstock	0	992,868	1,052,936	1,116,639	1,127,805	1,139,084	1,150,474	1,161,979	1,173,599	1,185,335	1,197,188
Chemicals, Enzymes & Yeast	0	152,730	154,257	155,800	157,358	158,932	160,521	162,126	163,747	165,385	167,039
Denaturant	0	54,525	55,615	56,727	57,862	59,019	60,200	61,404	62,632	63,884	65,162
Finished Product Inventory	0	1,021,205	1,148,746	1,217,981	1,233,333	1,240,416	1,250,200	1,267,807	1,286,657	1,305,655	1,322,244
Spare Parts	0	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Total Inventories	0	2,221,328	2,411,555	2,547,147	2,576,358	2,597,450	2,621,395	2,653,316	2,686,635	2,720,259	2,751,632
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	12,972,246	22,700,065	33,665,686	45,073,846	57,369,863	70,480,995	84,098,268	98,180,880	112,746,805	127,904,184
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	49,923,077	54,500,000	54,600,000	54,700,000	54,800,000	54,900,000	55,000,000	55,100,000	55,200,000	55,300,000	55,400,000
Less Accumulated Depreciation & Amortization	0	1,626,231	4,997,899	8,374,566	11,756,234	15,142,901	18,434,569	21,731,236	25,032,903	27,339,258	29,650,613
Net Property, Plant & Equipment	49,923,077	52,873,769	49,602,101	46,325,434	43,043,766	39,757,099	36,565,431	33,368,764	30,167,097	27,960,742	25,749,387
Capitalized Fees & Interest	(1,099,531)	(1,142,053)	(1,027,848)	(913,642)	(799,437)	(685,232)	(571,027)	(456,821)	(342,616)	(228,411)	(114,205)
Total Assets	48,923,546	64,803,962	71,374,319	79,177,477	87,418,175	96,541,730	106,575,400	117,110,211	128,105,361	140,579,135	153,639,365
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,455,581	1,581,574	1,678,391	1,700,418	1,706,855	1,718,271	1,744,266	1,772,502	1,800,926	1,824,740
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,455,581	1,581,574	1,678,391	1,700,418	1,706,855	1,718,271	1,744,266	1,772,502	1,800,926	1,824,740
Long Term Debt (excluding current maturities)	(11,071,210)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(11,071,210)	1,455,581	1,581,574	1,678,391	1,700,418	1,706,855	1,718,271	1,744,266	1,772,502	1,800,926	1,824,740
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,493,244)	1,860,381	8,304,745	16,011,086	24,229,757	33,346,875	43,369,130	53,877,945	64,844,858	77,290,209	90,326,625
Total Capital Shares & Equities	59,994,756	63,348,381	69,792,745	77,499,086	85,717,757	94,834,875	104,857,130	115,365,945	126,332,858	138,778,209	151,814,625
Total Liabilities & Equities	48,923,546	64,803,962	71,374,319	79,177,477	87,418,175	96,541,730	106,575,400	117,110,211	128,105,361	140,579,135	153,639,365

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #4
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	41,483,488	49,707,252	53,236,467	54,301,196	55,387,220	56,494,965	57,624,864	58,777,361	59,952,908	61,151,967
DDGS	0	10,677,539	12,908,666	13,692,379	13,832,041	13,973,099	14,115,568	14,259,462	14,404,795	14,551,581	14,699,835
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	52,518,550	63,015,918	67,328,846	68,533,237	69,760,319	71,010,533	72,284,326	73,582,156	74,904,490	76,251,802
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	32,847,380	36,852,774	39,082,367	39,473,191	39,867,923	40,266,602	40,669,268	41,075,961	41,486,720	41,901,587
Chemicals, Enzymes & Yeast	0	2,450,045	2,834,479	3,005,965	3,036,024	3,066,385	3,097,049	3,128,019	3,159,299	3,190,892	3,222,801
Natural Gas or Propane (Statrtup/Backup)	0	5,692,504	6,413,860	6,798,540	6,958,505	6,750,550	6,654,570	6,894,519	7,182,457	7,470,395	7,646,357
Electricity (Standby Charge)	0	1,260,023	1,472,165	1,576,689	1,608,222	1,640,387	1,673,195	1,706,659	1,740,792	1,775,608	1,811,120
Denaturants	0	1,166,221	1,362,570	1,459,313	1,488,499	1,518,269	1,548,635	1,579,607	1,611,199	1,643,423	1,676,292
Makeup Water	0	155,471	179,866	190,748	192,655	194,582	196,528	198,493	200,478	202,483	204,507
Wastewater Disposal	0	62,188	71,946	76,299	77,062	77,833	78,611	79,397	80,191	80,993	81,803
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	0	0	0	0	0	0	0	0	0	0
Lime and Limestone	0	0	0	0	0	0	0	0	0	0	0
Ammonia for SCR	0	0	0	0	0	0	0	0	0	0	0
Boiler Ash Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	0	1,043,900	1,069,998	1,096,747	1,124,166	1,152,270	1,181,077	1,210,604	1,240,869	1,271,891	1,303,688
Total Production Costs	0	44,677,731	50,257,658	53,286,667	53,958,325	54,268,198	54,696,266	55,466,565	56,291,246	57,122,405	57,848,156
Gross Profit	0	7,840,819	12,758,260	14,042,178	14,574,912	15,492,121	16,314,267	16,817,761	17,290,910	17,782,085	18,403,646
Administrative & Operating Expenses											
Maintenance Materials & Services	0	922,167	1,021,090	1,036,406	1,051,952	1,067,732	1,083,748	1,100,004	1,116,504	1,133,252	1,150,250
Repairs & Maintenance - Wages & Benefits	0	386,100	395,753	405,646	415,787	426,182	436,837	447,758	458,952	470,425	482,186
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	150,069	750,346	818,445	790,934	760,955	728,380	693,080	656,707	617,435	575,122	549,194
Admin. Salaries, Wages & Benefits	248,950	549,900	563,648	577,739	592,182	606,987	622,161	637,715	653,658	670,000	686,750
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,493,244)	4,979,856	9,701,826	10,968,804	11,486,133	12,389,581	13,199,717	13,691,277	14,154,376	14,637,501	15,233,565
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	1,626,231	3,257,462	3,262,462	3,267,462	3,272,462	3,177,462	3,182,462	3,187,462	2,192,150	2,197,150
Pre-Tax Income	(1,493,244)	3,353,625	6,444,364	7,706,341	8,218,670	9,117,118	10,022,255	10,508,815	10,966,913	12,445,351	13,036,416
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,493,244)	3,353,625	6,444,364	7,706,341	8,218,670	9,117,118	10,022,255	10,508,815	10,966,913	12,445,351	13,036,416

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #4
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,493,244)	3,353,625	6,444,364	7,706,341	8,218,670	9,117,118	10,022,255	10,508,815	10,966,913	12,445,351	13,036,416
Non cash charges to operations											
Depreciation & Amortization	0	1,626,231	3,257,462	3,262,462	3,267,462	3,272,462	3,177,462	3,182,462	3,187,462	2,192,150	2,197,150
	(1,493,244)	4,979,856	9,701,826	10,968,804	11,486,133	12,389,581	13,199,717	13,691,277	14,154,376	14,637,501	15,233,565
Changes in non-cash working capital balances											
Accounts Receivable	0	1,627,272	161,754	123,226	34,411	35,060	35,720	36,394	37,081	37,781	38,495
Inventories	0	2,221,328	190,227	135,592	29,211	21,092	23,945	31,921	33,319	33,624	31,373
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,455,581)	(125,993)	(96,817)	(22,027)	(6,437)	(11,416)	(25,995)	(28,236)	(28,424)	(23,814)
	0	2,393,018	225,989	162,002	41,595	49,714	48,250	42,320	42,163	42,981	46,054
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	49,923,077	4,576,923	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	(1,099,531)	(42,522)	0	0	0	0	0	0	0	0	0
	48,923,546	4,534,401	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Long Term Debt Advances	(11,071,210)	11,071,210	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	61,488,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	9,123,647	9,375,837	10,706,802	11,344,537	12,239,866	13,051,467	13,548,958	14,012,212	14,494,520	15,087,511
Cash (Indebtedness), Beginning of Year	0	0	9,123,647	18,499,484	29,206,286	40,550,823	52,790,689	65,842,157	79,391,114	93,403,326	107,897,846
Cash (Bank Indebtedness), End of Year	0	9,123,647	18,499,484	29,206,286	40,550,823	52,790,689	65,842,157	79,391,114	93,403,326	107,897,846	122,985,357

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	61,488,000										
Annual Cash Flows	0	9,123,647	9,375,837	10,706,802	11,344,537	12,239,866	13,051,467	13,548,958	14,012,212	14,494,520	15,087,511
Equity & Cash Flows used for IRR & NPV Calcs	(61,488,000)	9,123,647	9,375,837	10,706,802	11,344,537	12,239,866	13,051,467	13,548,958	14,012,212	14,494,520	15,087,511
Internal Rate of Return (IRR)	**13.6%**										
Net Present Value, 8% discount rate	**$16,765,000**										
Net Present Value, 15% discount rate	**($3,206,000)**										

Financial Forecast for Site #5 – 40 MMGPY Natural Gas-Fired Plants

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #5
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	40,000,000
Anhydrous Ethanol Production (gal/year)	38,182,512
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Nameplate	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	35,752,381	42,000,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	44,100,000	
Ethanol Price ($/gal)	$1.2700	$1.2954	$1.3213	$1.3477	$1.3747	$1.4022	$1.4302	$1.4588	$1.4880	$1.5178	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.0970	$0.0989	$0.1009	$0.1029	$0.1050	$0.1071	$0.1092	$0.1114	$0.1137	$0.1159	2.00%
Delivered Grain Price ($/bu)	$2.4300	$2.4543	$2.4788	$2.5036	$2.5287	$2.5540	$2.5795	$2.6053	$2.6313	$2.6577	1.00%
Grain Elevator Handling Fee ($/bu)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Grain Usage (bu/year)	13,108,853	15,015,595	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	15,766,375	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	112,923	135,140	141,897	141,897	141,897	141,897	141,897	141,897	141,897	141,897	
DDGS Price, FOB ($/ton)	$96.485	$97.450	$98.425	$99.409	$100.403	$101.407	$102.421	$103.445	$104.480	$105.525	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	$1.930	0.00%
% DWG Produced	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DWG Price, FOB ($/ton)	$39.309	$39.702	$40.099	$40.500	$40.905	$41.314	$41.727	$42.144	$42.566	$42.991	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	$0.786	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	112,622	132,302	138,918	138,918	138,918	138,918	138,918	138,918	138,918	138,918	
CO2 Price ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
Electricity Use (kWh/bu)	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	2.136	
Annual Electricity Use (million kWh/year)	28.001	32.073	33.677	33.677	33.677	33.677	33.677	33.677	33.677	33.677	
Electricity Price ($/kWh)	$0.0450	$0.0459	$0.0468	$0.0478	$0.0487	$0.0497	$0.0507	$0.0517	$0.0527	$0.0538	2.00%
Natural Gas Use (MMBTU/bu)	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	0.1015	
Annual Natural Gas Use (MMBTU/year)	1,330,024	1,523,482	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	1,599,656	
Natural Gas Price ($/MMBTU)	$4.280	$4.210	$4.250	$4.350	$4.220	$4.160	$4.310	$4.490	$4.670	$4.780	0.00%
Fresh Water Use (1000 gal/bu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	
Annual Fresh Water Use (1000 gal/year)	155,471	178,085	186,989	186,989	186,989	186,989	186,989	186,989	186,989	186,989	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	31,094	35,617	37,398	37,398	37,398	37,398	37,398	37,398	37,398	37,398	
Effluent Water Disposal Price ($/1000 gal)	$2.0000	$2.0200	$2.0402	$2.0606	$2.0812	$2.1020	$2.1230	$2.1443	$2.1657	$2.1874	1.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #5
Production Assumptions, continued

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Denaturant Use (% of ethanol sold)	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	4.760%	
Annual Denaturant Use (gal/year)	1,666,030	1,908,362	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	2,003,780	
Denaturant Price ($/gal)	$0.7000	$0.7140	$0.7283	$0.7428	$0.7577	$0.7729	$0.7883	$0.8041	$0.8202	$0.8366	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Lignite Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lignite Cost, at mine ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Lignite Transportation Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.50%
Lignite Cost, delivered ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Lime and Limestone Use (tons/year)	0	0	0	0	0	0	0	0	0	0	
Lime and Limestone Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Ammonia Use for SCR (tons/year)	0	0	0	0	0	0	0	0	0	0	
Ammonia Cost ($/tons)	$0.00	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	1.00%
Boiler Ash Produced (tons/year)	0	0	0	0	0	0	0	0	0	0	
Boiler Ash Disposal Cost ($/ton)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	2.00%
Number of Employees	36	36	36	36	36	36	36	36	36	36	
Average Salary Including Benefits	$54,997	$56,372	$57,781	$59,226	$60,707	$62,224	$63,780	$65,374	$67,009	$68,684	2.50%
Maintenance Materials & Services (% of Capital E	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Prop	1.500%	1.545%	1.591%	1.639%	1.688%	1.739%	1.791%	1.845%	1.900%	1.957%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #5
Financial Assumptions

Project Engineering & Construction Costs	
Ethanol Plant Capital Cost	$45,000,000
Unit Train Rail Improvements	$1,300,000
Additional Grain Handling and Storage	$1,000,000
Cogeneration System	$3,000,000
Total Engineering and Construction Cost	$50,300,000
Development Costs	
Inventory - Grain	$910,000
Inventory - Lignite/Chemicals/Denaturant	$207,000
Inventory - Ethanol & DDGS	$1,021,000
Inventory - Spare Parts	$450,000
Startup Costs	$750,000
Land	$100,000
Administration Building & Furnishing	$300,000
Rail Improvements	$950,000
Well & Process Water Treatment	$600,000
Site Development Costs	$1,500,000
Rolling Stock and Shop Equipment	$400,000
Organizational Costs	$1,100,000
Capitalized Fees and Interest	$1,900,000
Contingency	$1,000,000
Total Development Costs	$11,188,000
Total Estimated Project Cost	$61,488,000

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	10		8
Distillers Grain	10		8
Denaturants		15	15
Lignite, Chemicals & Enzymes		15	20
Grain		10	10
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	10.00%

State Producer Payment	
Producer payment, $/gal	$0.0400
Annual payment cap	$400,000
Incentive duration, years	10

Other Incentive Payments	
Small Producer Tax Credit	No
CCC Bioenergy Program	No

Plant Operating Rate	
Month	% of Nameplate
13	0.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Working Capital at Startup:		
Cash at Startup	$5,878,172	(see Interim Funding Schedule (page 7), Construction Loan Balance in month 14)
Operating Line of Credit	$1,294,000	(50% of the value of inventory at startup)
Total Capital at Startup	$7,172,172	
Capital/gallon of capacity	$0.179	(10¢/gal is the typical requirement for US Lenders)

Senior Debt (see note 1 below)		
Principal	$0	0.00%
Interest Rate	8.0%	fixed
Lender Fees	$0	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	

Subordinated Debt		
Principal	$0	0.00%
Interest Rate	12.00%	fixed rate
Lender Fees	$0	2.000%
Placement Fees	$0	2.000%
Amortization Period	10	years

Equity Investment		
Total Equity Amount	$61,488,000	100.00%
Placement Fees	$614,880	1.000%
Preferred Shares	$0	0.000%
Common Shares	$61,488,000	100.000%

Grants
Amount
$0
0.00%

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #5
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	9,123,647	18,499,484	29,206,286	40,550,823	52,790,689	65,842,157	79,391,114	93,403,326	107,897,846	122,985,357
Accounts Receivable - Trade	0	1,627,272	1,789,026	1,912,253	1,946,664	1,981,723	2,017,444	2,053,838	2,090,919	2,128,700	2,167,194
Inventories											
Feedstock	0	992,868	1,052,936	1,116,639	1,127,805	1,139,084	1,150,474	1,161,979	1,173,599	1,185,335	1,197,188
Chemicals, Enzymes & Yeast	0	152,730	154,257	155,800	157,358	158,932	160,521	162,126	163,747	165,385	167,039
Denaturant	0	54,525	55,615	56,727	57,862	59,019	60,200	61,404	62,632	63,884	65,162
Finished Product Inventory	0	1,021,205	1,148,746	1,217,981	1,233,333	1,240,416	1,250,200	1,267,807	1,286,657	1,305,655	1,322,244
Spare Parts	0	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Total Inventories	0	2,221,328	2,411,555	2,547,147	2,576,358	2,597,450	2,621,395	2,653,316	2,686,635	2,720,259	2,751,632
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	12,972,246	22,700,065	33,665,686	45,073,846	57,369,863	70,480,995	84,098,268	98,180,880	112,746,805	127,904,184
Land	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	49,923,077	54,500,000	54,600,000	54,700,000	54,800,000	54,900,000	55,000,000	55,100,000	55,200,000	55,300,000	55,400,000
Less Accumulated Depreciation & Amortization	0	1,626,231	4,997,899	8,374,566	11,756,234	15,142,901	18,434,569	21,731,236	25,032,903	27,339,258	29,650,613
Net Property, Plant & Equipment	49,923,077	52,873,769	49,602,101	46,325,434	43,043,766	39,757,099	36,565,431	33,368,764	30,167,097	27,960,742	25,749,387
Capitalized Fees & Interest	(1,099,531)	(1,142,053)	(1,027,848)	(913,642)	(799,437)	(685,232)	(571,027)	(456,821)	(342,616)	(228,411)	(114,205)
Total Assets	48,923,546	64,803,962	71,374,319	79,177,477	87,418,175	96,541,730	106,575,400	117,110,211	128,105,361	140,579,135	153,639,365
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	1,455,581	1,581,574	1,678,391	1,700,418	1,706,855	1,718,271	1,744,266	1,772,502	1,800,926	1,824,740
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,455,581	1,581,574	1,678,391	1,700,418	1,706,855	1,718,271	1,744,266	1,772,502	1,800,926	1,824,740
Long Term Debt (excluding current maturities)	(11,071,210)	0	0	0	0	0	0	0	0	0	0
Subordinated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	(11,071,210)	1,455,581	1,581,574	1,678,391	1,700,418	1,706,855	1,718,271	1,744,266	1,772,502	1,800,926	1,824,740
Capital Shares & Equities											
Preferred Shares	0	0	0	0	0	0	0	0	0	0	0
Common Shares	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000	61,488,000
Grants	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,493,244)	1,860,381	8,304,745	16,011,086	24,229,757	33,346,875	43,369,130	53,877,945	64,844,858	77,290,209	90,326,625
Total Capital Shares & Equities	59,994,756	63,348,381	69,792,745	77,499,086	85,717,757	94,834,875	104,857,130	115,365,945	126,332,858	138,778,209	151,814,625
Total Liabilities & Equities	48,923,546	64,803,962	71,374,319	79,177,477	87,418,175	96,541,730	106,575,400	117,110,211	128,105,361	140,579,135	153,639,365

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #5
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	41,483,488	49,707,252	53,236,467	54,301,196	55,387,220	56,494,965	57,624,864	58,777,361	59,952,908	61,151,967
DDGS	0	10,677,539	12,908,666	13,692,379	13,832,041	13,973,099	14,115,568	14,259,462	14,404,795	14,551,581	14,699,835
DWG	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	357,524	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Federal Small Producer Tax Credit	0	0	0	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	52,518,550	63,015,918	67,328,846	68,533,237	69,760,319	71,010,533	72,284,326	73,582,156	74,904,490	76,251,802
Ethanol Plant Production & Operating Expenses											
Feedstocks	0	32,847,380	36,852,774	39,082,367	39,473,191	39,867,923	40,266,602	40,669,268	41,075,961	41,486,720	41,901,587
Chemicals, Enzymes & Yeast	0	2,450,045	2,834,479	3,005,965	3,036,024	3,066,385	3,097,049	3,128,019	3,159,299	3,190,892	3,222,801
Natural Gas or Propane (Statrtup/Backup)	0	5,692,504	6,413,860	6,798,540	6,958,505	6,750,550	6,654,570	6,894,519	7,182,457	7,470,395	7,646,357
Electricity (Standby Charge)	0	1,260,023	1,472,165	1,576,689	1,608,222	1,640,387	1,673,195	1,706,659	1,740,792	1,775,608	1,811,120
Denaturants	0	1,166,221	1,362,570	1,459,313	1,488,499	1,518,269	1,548,635	1,579,607	1,611,199	1,643,423	1,676,292
Makeup Water	0	155,471	179,866	190,748	192,655	194,582	196,528	198,493	200,478	202,483	204,507
Wastewater Disposal	0	62,188	71,946	76,299	77,062	77,833	78,611	79,397	80,191	80,993	81,803
Cogen Plant Production & Operating Expenses											
Lignite Fuel (delivered)	0	0	0	0	0	0	0	0	0	0	0
Lime and Limestone	0	0	0	0	0	0	0	0	0	0	0
Ammonia for SCR	0	0	0	0	0	0	0	0	0	0	0
Boiler Ash Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	0	1,043,900	1,069,998	1,096,747	1,124,166	1,152,270	1,181,077	1,210,604	1,240,869	1,271,891	1,303,688
Total Production Costs	0	44,677,731	50,257,658	53,286,667	53,958,325	54,268,198	54,696,266	55,466,565	56,291,246	57,122,405	57,848,156
Gross Profit	0	7,840,819	12,758,260	14,042,178	14,574,912	15,492,121	16,314,267	16,817,761	17,290,910	17,782,085	18,403,646
Administrative & Operating Expenses											
Maintenance Materials & Services	0	922,167	1,021,090	1,036,406	1,051,952	1,067,732	1,083,748	1,100,004	1,116,504	1,133,252	1,150,250
Repairs & Maintenance - Wages & Benefits	0	386,100	395,753	405,646	415,787	426,182	436,837	447,758	458,952	470,425	482,186
Consulting Services	155,250	8,000	8,160	8,323	8,490	8,659	8,833	9,009	9,189	9,373	9,561
Property Taxes & Insurance	150,069	750,346	818,445	790,934	760,955	728,380	693,080	656,707	617,435	575,122	549,194
Admin. Salaries, Wages & Benefits	248,950	549,900	563,648	577,739	592,182	606,987	622,161	637,715	653,658	670,000	686,750
Legal & Accounting/Community Affairs	436,500	107,125	109,268	111,453	113,682	115,956	118,275	120,640	123,053	125,514	128,024
Office/Lab Supplies & Other Expenses	412,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	89,975	41,325	42,152	42,995	43,854	44,732	45,626	46,539	47,469	48,419	49,387
EBITDA	(1,493,244)	4,979,856	9,701,826	10,968,804	11,486,133	12,389,581	13,199,717	13,691,277	14,154,376	14,637,501	15,233,565
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	0	0	0	0	0	0	0	0	0	0
Interest - Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	1,626,231	3,257,462	3,262,462	3,267,462	3,272,462	3,177,462	3,182,462	3,187,462	2,192,150	2,197,150
Pre-Tax Income	(1,493,244)	3,353,625	6,444,364	7,706,341	8,218,670	9,117,118	10,022,255	10,508,815	10,966,913	12,445,351	13,036,416
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,493,244)	3,353,625	6,444,364	7,706,341	8,218,670	9,117,118	10,022,255	10,508,815	10,966,913	12,445,351	13,036,416

North Dakota Feasibility Study - Natural Gas Powered Ethanol Plant, Site #5
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,493,244)	3,353,625	6,444,364	7,706,341	8,218,670	9,117,118	10,022,255	10,508,815	10,966,913	12,445,351	13,036,416
Non cash charges to operations											
Depreciation & Amortization	0	1,626,231	3,257,462	3,262,462	3,267,462	3,272,462	3,177,462	3,182,462	3,187,462	2,192,150	2,197,150
	(1,493,244)	4,979,856	9,701,826	10,968,804	11,486,133	12,389,581	13,199,717	13,691,277	14,154,376	14,637,501	15,233,565
Changes in non-cash working capital balances											
Accounts Receivable	0	1,627,272	161,754	123,226	34,411	35,060	35,720	36,394	37,081	37,781	38,495
Inventories	0	2,221,328	190,227	135,592	29,211	21,092	23,945	31,921	33,319	33,624	31,373
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(1,455,581)	(125,993)	(96,817)	(22,027)	(6,437)	(11,416)	(25,995)	(28,236)	(28,424)	(23,814)
	0	2,393,018	225,989	162,002	41,595	49,714	48,250	42,320	42,163	42,981	46,054
Investing Activities											
Land Purchase	100,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	49,923,077	4,576,923	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	(1,099,531)	(42,522)	0	0	0	0	0	0	0	0	0
	48,923,546	4,534,401	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Long Term Debt Advances	(11,071,210)	11,071,210	0	0	0	0	0	0	0	0	0
Repayment of Long Term Debt	0	0	0	0	0	0	0	0	0	0	0
Subordinated Debt Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	61,488,000	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	9,123,647	9,375,837	10,706,802	11,344,537	12,239,866	13,051,467	13,548,958	14,012,212	14,494,520	15,087,511
Cash (Indebtedness), Beginning of Year	0	0	9,123,647	18,499,484	29,206,286	40,550,823	52,790,689	65,842,157	79,391,114	93,403,326	107,897,846
Cash (Bank Indebtedness), End of Year	0	9,123,647	18,499,484	29,206,286	40,550,823	52,790,689	65,842,157	79,391,114	93,403,326	107,897,846	122,985,357

Profitability

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Equity Investment	61,488,000										
Annual Cash Flows	0	9,123,647	9,375,837	10,706,802	11,344,537	12,239,866	13,051,467	13,548,958	14,012,212	14,494,520	15,087,511
Equity & Cash Flows used for IRR & NPV Calcs	(61,488,000)	9,123,647	9,375,837	10,706,802	11,344,537	12,239,866	13,051,467	13,548,958	14,012,212	14,494,520	15,087,511
Internal Rate of Return (IRR)	**13.6%**										
Net Present Value, 8% discount rate	**$16,765,000**										
Net Present Value, 15% discount rate	**($3,206,000)**										