GRANT APPLICATION

for

SPIRIT ENERGY POWER PLANT PROJECT

***Submitted by*:**

17845 East Highway 10
P.O. Box 800
Elk River, MN 55330-0800

Principal Investigators:

Greg Ridderbusch Vice President, Business Development	Richard Lancaster Vice President, Generation

Date: July 3, 2006

Amount Requested:$10,000,000

Submitted to:

Ms. Karlene Fine, Executive Director
North Dakota Industrial Commission
600 East Boulevard Avenue
State Capitol, 10th Floor
Bismarck, ND 58505-0310

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Greg Ridderbusch, VP, Business Development

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Richard Lancaster, VP, Generation

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Abstract

Introduction

Great River Energy (GRE), Cargill Malt Americas (Cargill), and the Newman Group (Newman) have partnered to develop the Spirit Energy Power Plant an integral part of the Spiritwood Energy Park. In addition to producing electric power, the power plant will produce low-pressure steam to support the construction and operation of the Newman Group's new 100-million-gallon ethanol plant and to support a 30 percent expansion in the Cargill Malt Americas facility. The design and operating characteristics of the combined heat and power (CHP) technology results in highly competitive electric and steam energy rates. It is the low cost of the steam energy that enables the Newman Group and Cargill to develop and expand their business in North Dakota.

The project will create short- and long-term employment opportunities in North Dakota. Construction of the Spirit Energy Power Plant will provide an estimated 200 construction jobs in the first year alone. Normal power plant operations are expected to employ approximately 20 people.

The project will open new markets for North Dakota's lignite reserves. The Spirit Energy Power Plant will also be the first power generating facility to be fired with beneficiated North Dakota lignite as the design coal. The GRE, Cargill and Newman partnership allows for the expanded use of lignite coal in North Dakota, the innovative use of beneficiated lignite coal, and the introduction of lignite-driven power production in the eastern half of North Dakota.

Objectives

The objective of this application is to construct and operate a beneficiated lignite-fired combined heat and power (CHP) plant near Spiritwood, North Dakota. The project will showcase, and set a precedent for the use of beneficiated coal. A successful Spirit Energy power plant will increase the demand for North Dakota lignite, and help foster growth in North Dakota's agricultural economy, creating significant economic growth for the state. The Spiritwood Energy Partners (The Partners); GRE, Newman and Cargill, anticipate entering in to negotiated payback terms with the State to cover the costs of the bonds. The Partners believe that financial support from the State is critical to obtaining senior debt financing from the lending community.

Expected Results

Construction negotiations for the Spirit Energy Power Plant are underway. Success will be determined by commercial operation of the Spirit Power facility in 2009, expansion of Cargill's malt plant, and construction of the Newman Group's new ethanol plant.

Duration

Project participants have completed feasibility studies and preliminary reviews of permitting requirements, transmission interconnect, and project design of a generating plant and transmission facilities to deliver reliable, competitively priced electricity to the market. Commercial operation is anticipated for March 2009.

Total Project Cost

The current estimated cost for the entire Spiritwood Energy Park is $350 million.

Participants

Great River Energy will construct the Spirit Energy Power Plant as part of a partnership with Cargill Malt Americas and the Newman Group to create the Spiritwood Energy Park, which will include Spirit Ethanol and a 30 percent expansion of the Cargill malt plant.

Project Summary

Great River Energy (GRE), Cargill Malt Americas (Cargill), and The Newman Group (Newman) have completed the feasibility studies and preliminary reviews of permitting requirements, transmission inter-connect, and project design for the Spirit Energy Power Plant, a beneficiated lignite-fired combined heat and power plant. These studies indicate that Spirit Energy will be a successful business endeavor for the project participants and the state of North Dakota. The Spirit Energy Plant will be the first commercial application of beneficiated lignite, which will set a precedent and open new markets for North Dakota lignite. The low-pressure steam produced by Spirit Energy as a by-product of power generation will be purchased by its partners in the Spiritwood Energy Park, Cargill Malt Americas, which will expand its facilities by 30 percent, and the Newman Group, which will construct a new ethanol plant.

Spirit Energy will provide an estimated $380,000,000 economic impact to North Dakota while providing a showcase for an innovative fuel choice in the form of beneficiated North Dakota lignite coal.

Project Description

Overview

GRE, Cargill, and Newman have partnered to develop the Spirit Energy Power Plant, as part of the Spiritwood Energy Park to be located near Spiritwood, North Dakota, which is approximately 10 miles east of Jamestown, North Dakota, and 90 miles west of Fargo, North Dakota. The Spiritwood Energy Park will be constructed on a portion of the existing Cargill site. The Spirit Energy Power Plant will be a coal-fired combined heat and power (CHP) plant fueled with beneficiated lignite as the design coal. Low-cost process steam made available by the power plant will provide an energy source that will allow Newman and Cargill to make development and expansion of their companies economically feasible. The partnership of these three entities will expand the use of lignite coal in North Dakota, incorporate the use of innovative beneficiated lignite coal, and introduce lignite-driven power production in the eastern half of North Dakota.

Proposed Combined Heat and Power Plant

Spirit Energy will be the first commercial application of beneficiated lignite in North Dakota. The beneficiation process was recently developed through the support of a cooperative agreement between the Lignite Research Council and the DOE/NETL (National Energy Technology Lab) Clean Coal Power Initiative (CCPI) Lignite Fuel Enhancement Project. The beneficiation process increases the heat value of lignite coal by reducing its moisture content and makes it practical to ship lignite to some markets currently powered by Powder River Basin coal. The successful execution of this project will establish a precedent for the use of beneficiated lignite coal in local markets and increase the demand for lignite produced in North Dakota.

Ownership of the Spiritwood Energy CHP plant will be a joint venture between GRE, Newman, and Cargill. Newman will own 41%, GRE will own 40%, and Cargill will own 19%. Each partner will be required to invest cash equity into Spiritwood Energy. The joint venture will likely be a limited liability corporation ("LLC"). The by-laws of the LLC will require the three partners to work cooperatively and, hence, from a governance standpoint, one partner will equate to one vote. The LLC will enter into separate life-of-plant contracts with Newman and Cargill for process steam and with GRE for power and electric energy. GRE will operate and maintain the CHP plant under an agency agreement with the LLC.

Great River Energy's 80 MW-equivalent CHP plant will use about 600,000 tons of lignite coal annually from the Falkirk Mine. The CHP main boiler will be an atmospheric-circulating fluidized bed firing dried lignite with a heat input capacity of 910 MMBtu/hr. The lignite will be dried at GRE's Coal Creek Station. The gross output of the CHP will be 35–50 MWe. The net electric output of Spirit Energy will be contracted electricity delivered to the grid. The CHP will generate 760,000 lb/hr of steam; 394,000 lb/hr will be contracted process steam to the ethanol plant, and 200,000 lb/hr will be contracted process steam to the malting plant. The balance of the steam produced will be used for feedwater heating.

In addition to the main boiler at the CHP plant, there will be three natural-gas/propane-fired auxiliary boilers each with a heat input capacity of 220 MMBtu/hr, each; three diesel engines for the back-up boiler feedwater pump, the emergency fire pump, and the back-up generator set; and the storage and handling of coal, lime, limestone, ash, and activated carbon.

Proposed Ethanol Production Facility

A separate corporate entity will be formed for ownership and operation of the Spirit Ethanol plant. The Newman Group, a North Dakota business, will be the majority owner and operator. The ethanol company plans to construct and operate a nominal 100-million-gallon-per-year ethanol-production facility. The ethanol plant will be designed to use steam-driven processes, such as steam-heated rotary dryers, and will purchase steam under a steam contract with the CHP. The projected steam demand of the ethanol production facility is 760,000lb/hr represents 51.8% of the steam produced by the CHP.

Cargill Malting Plant Expansion

Cargill Malt will complete a 30 percent expansion of its existing facility at the Spiritwood Industrial Park site, increasing its annual purchase of barley from 20 to 28 million bushels. Cargill Malt operates seven natural-gas-fired kilns and already has received a required permit for expansion of one kiln. Cargill's kilns will be converted to steam heat to allow the company to break from the volatile natural-gas market and instead utilize a firm supply of process steam from the power plant. The projected steam demand resulting from the expansion of the Cargill Malt facility is 200,000lb/hr, which represents 26.3% of the steam produced by the CHP plant.

Economic Analysis

In addition to the precedent created for the use of beneficiated lignite in North Dakota, the economic impact of the construction and operation of Spirit Energy will be substantial. It is estimated that Spirit Energy will bring $380million per year to North Dakota communities, while fostering economic growth throughout the state.

The Spiritwood Energy Park's direct economic impact will come from construction jobs, long-term operating jobs, North Dakota tax revenue and payments to the private sector. Construction will provide 880 jobs and operations will provide 123 jobs. Spirit Energy will provide 400 construction jobs and 19 operations jobs; Spirit Ethanol and Cargill will provide a combined total of 400 construction jobs and 50 operations jobs; and the lignite production facility will create 80 construction jobs and 24 operations jobs. Great River Energy estimates that it will pay an additional $388,122 per year to the state through the coal severance tax and coal conversion tax. It is also estimated that $4,613,824 will be paid annually to North Dakota short-line railroads with $800,000 paid annually to the local natural-gas distribution company.

Environmental

The Spirit Energy Power Plant, in combination with its principal steam customers, will achieve a significantly higher heat rate (i.e. MMBtu/MWh) than is provided by traditional coal-fired utility boilers. Traditional coal-fired units are typically 30-35% energy efficient. The Spirit Energy power plant is expected to be at least 83.2% efficient. With this efficiency improvement, the plant will emit correspondingly less CO_2 per unit of energy generated than typical coal-fired generation units.

Major permits that the power plant will be required to obtain include environmental permits for air emissions, wastewater discharges, and plant water appropriation. As a new source of air emissions at levels that trigger federal permitting requirements, the power plant project will be required to prepare an analysis of best available control technologies and to demonstrate that controlled emissions will not be protective of national ambient air quality standards (NAAQS) and increments. The project is also subject to several additional air quality programs with emission standards that will require stringent control of particulate matter, nitrogen oxides, sulfur dioxide, and mercury. A detailed review of the environmental approval aspects of the project is provided in Appendix E.

Standards of Success

Project participants have completed feasibility studies and preliminary reviews of permitting requirements, transmission interconnect, and project design of a generating plant and transmission facilities to deliver reliable, competitively priced electricity to the market. With these phases complete, obtaining financial backing is the greatest challenge to the viability of this project. The financial support of this project by the North Dakota Industrial Commission is essential in convincing investors to commit funds. Success of this project will be demonstrated by the acquisition of grant funding and the subsequent funding from other institutions.

The success of this project will also be demonstrated by the commercial use of beneficiated coal and the construction of the first lignite-fired power plant built since 1984. The $380,000,000 annual economic impact will be the largest economic development in North Dakota since the construction of the railroad. This project will also expand the use of lignite into the eastern half of North Dakota, which is currently underrepresented in the state's power generation industry.

Further funding information can be found in Appendix F.

The development of a low-cost, reliable energy source has been a priority and a concern for all three partners of the Spiritwood Energy Park. Cargill Malt Americas currently endures volatile gas prices, as well as curtailment due to fixed gas-line capacity. During this time of strong worldwide competition in the malt industry, Cargill has been searching for an alternate fuel source, including the construction of its own coal-fired boiler, to ensure its future success. The Newman Group operates a coal-fired ethanol plant in Grafton, North Dakota. Their interest in expanding their role in the expanding ethanol market hinges on the use of a low-cost, efficient energy source. The North Dakota Economic Development Commission has recognized the correlation between the interests of these two groups, which led to discussions of building a power plant to meet the process-steam and energy demands for both facilities.

With statewide electric load deficits increasing, GRE joined the partnership to provide steam to both facilities while adding power-generation capacity to decrease the predicted power-grid deficits. Great River Energy's long-term load forecasts show a baseload deficit large enough to consider resource additions beginning in 2008. The chart below illustrates the increasing load deficits between 2005 and 2020.

GRE Summer Resource Surplus/Deficit

Year	Surplus/Deficit (MW)
2005	-23
2006	-57
2007	-20
2008	-121
2009	-224
2010	-477
2011	-493
2012	-595
2013	-700
2014	-816
2015	-1097
2016	-1176
2017	-1294
2018	-1408

2019	-1524
2020	-1637

All three parties have assessed their potential for future growth, and have concluded that the construction of the Spirit Energy Power Plant will make it economically feasible for this development to take place.

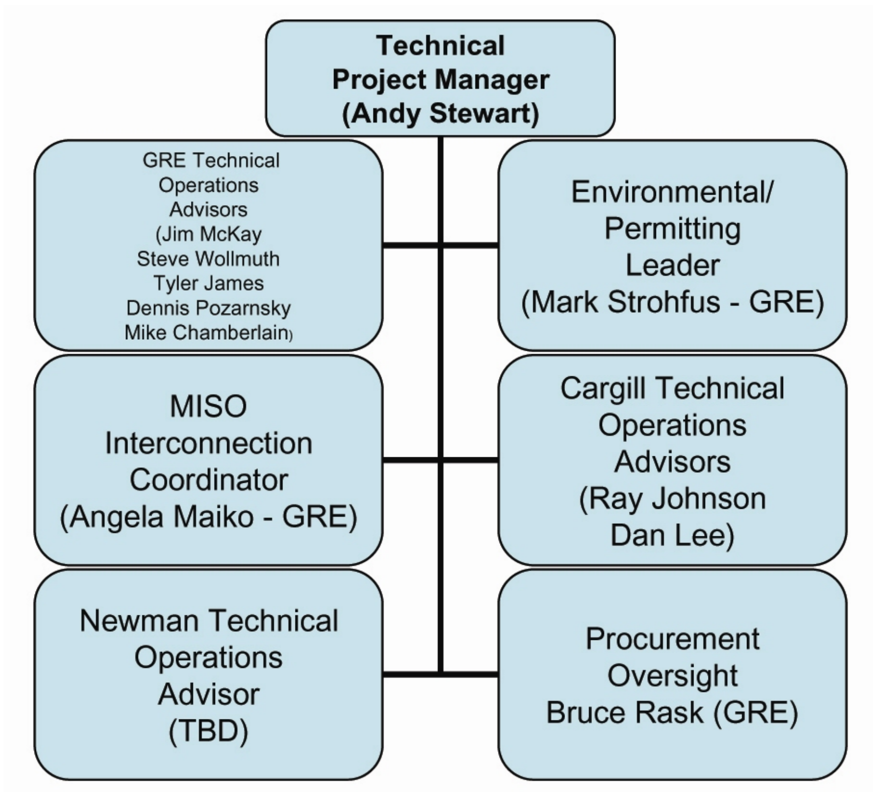
Qualifications

Mr. Richard Lancaster, vice president of generation, and Mr. Greg Ridderbusch, vice president of business development and strategy, will act as principal investigators on this project. Mr. Lancaster has 25 years of experience in the energy field. His experience includes 13 years in regulatory and energy policy positions with the state of Minnesota. Prior to moving to industry in 1993, Mr. Lancaster was the Executive Secretary of the Minnesota Public Utilities Commission. Since, 1993, Mr. Lancaster has been with Cooperative Power and its successor, Great River Energy.

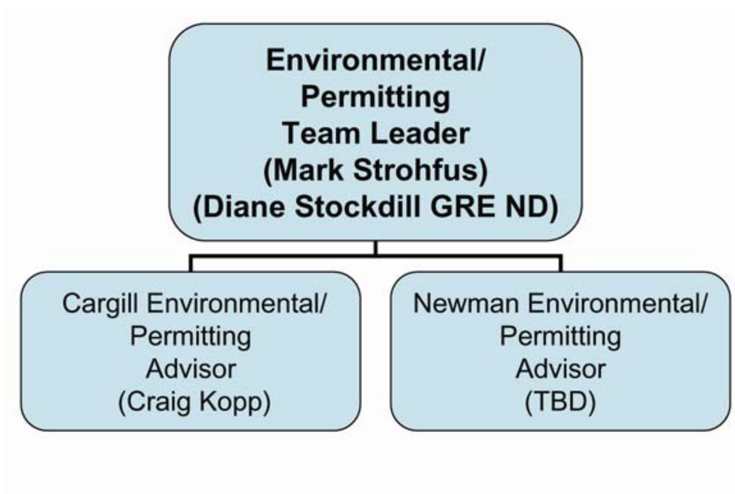
Mr. Ridderbusch has been Great River Energy's vice president, business development and strategy since August 2005. This position is responsible to provide strategic leadership in the evaluation, development, and operation of new business opportunities, and to support the corporate strategic and business planning processes, to benefit members and support the growth objectives of Great River Energy. He was previously a Utility Management Consultant serving cooperatives, municipals, and investor owned utilities across the United States. His expertise focused on serving executive management teams and governance groups in the area of strategy, business analysis, business planning, financial analysis, technology strategy, and customer marketing.

Great River Energy has identified several other key staff members to lead the engineering and construction, finance, partnership development, stakeholder relations, and operations teams. The project managers and the organization of their team structures are listed in the diagrams below. Resumes for the project managers can be found in Appendix C.

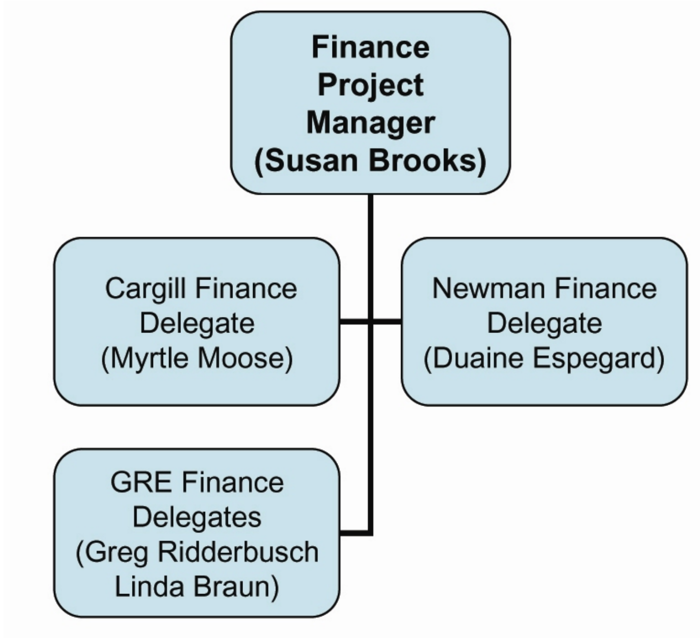
Engineering and Construction Team



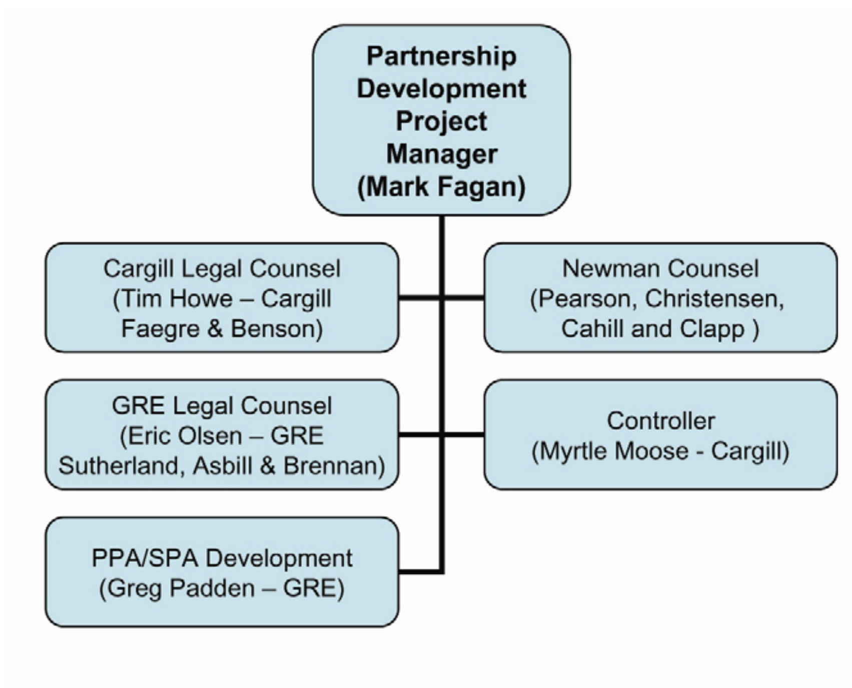
Environmental/Permitting Subteam



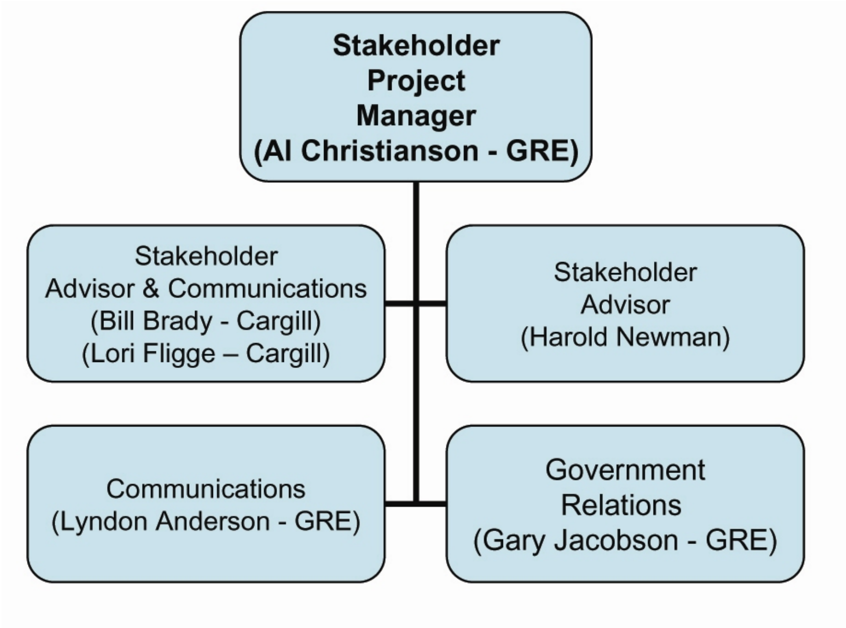
Finance Team



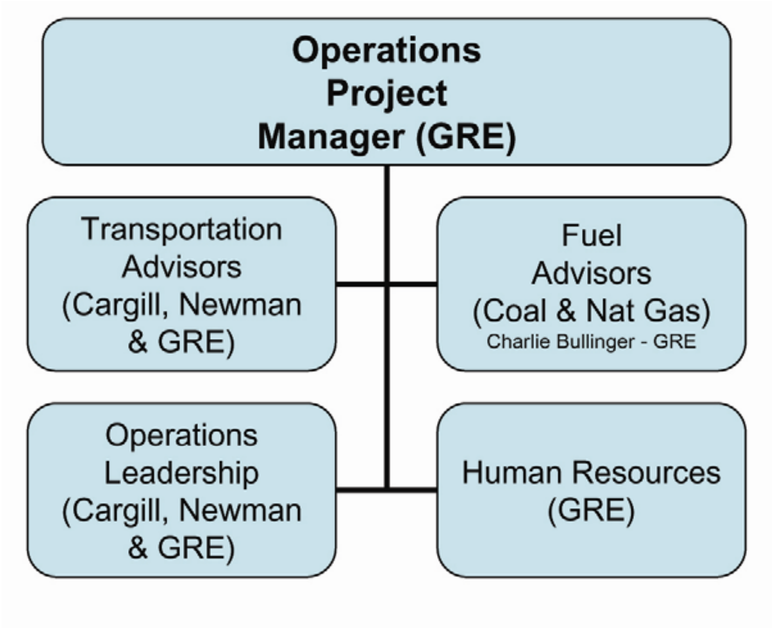
Partnership Development Team



Stakeholder Relations Team



Operations Team



Value to North Dakota

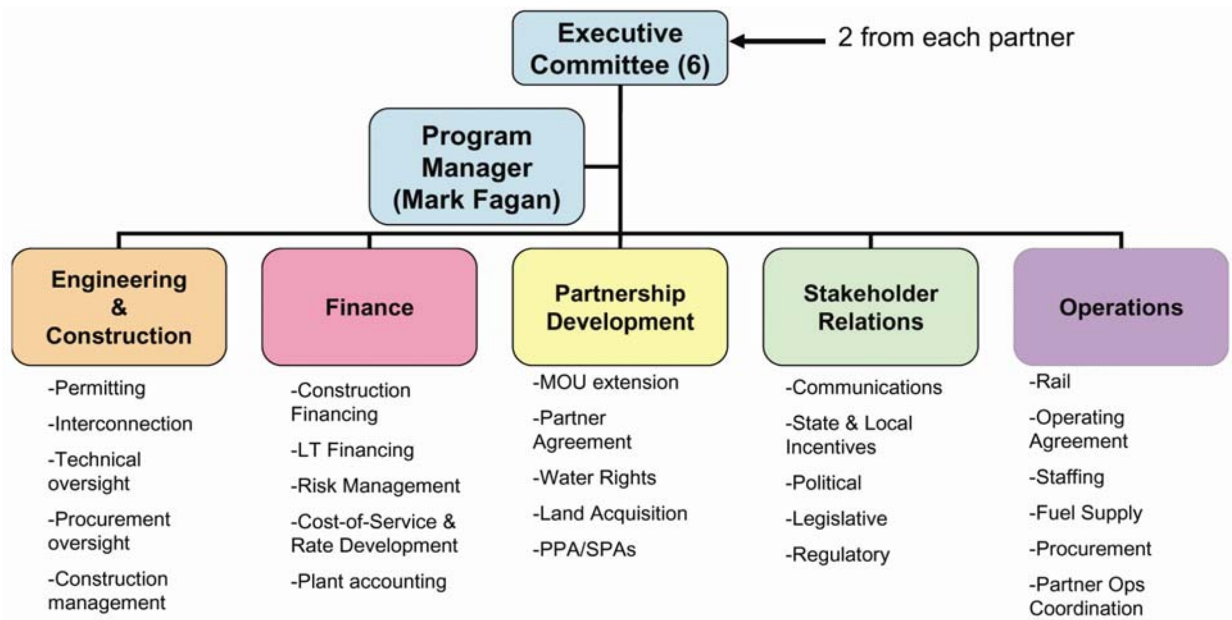
The energy industry plays a significant role in North Dakota's economy. The industry has, however, reached a plateau, with no major new expansion since the mid-1980's. This project will be the first commercial use of the Department of Energy's Lignite Coal Enhancement Project's coal-drying technology, which was developed with North Dakota lignite. A successful beneficiated lignite-fired project will put the spotlight on North Dakota lignite as a cost-effective fuel alternative.

The partnership of Great River Energy, the Newman Group, and Cargill Malt Americas will provide not only development to the energy industry, but will also contribute to North Dakota's expanding alternative fuels market through the construction of a 100-million-gallon ethanol plant. Cargill, using steam from the combined heat and power plant, will expand the size of its plant by 30 percent while reducing its demand for natural gas and cutting costs. Spirit Energy's 80 MW-equivalent power plant will supply a total of 760Klbs/hr of steam to the ethanol plant and malting plant while producing 35-50MW of electric power.

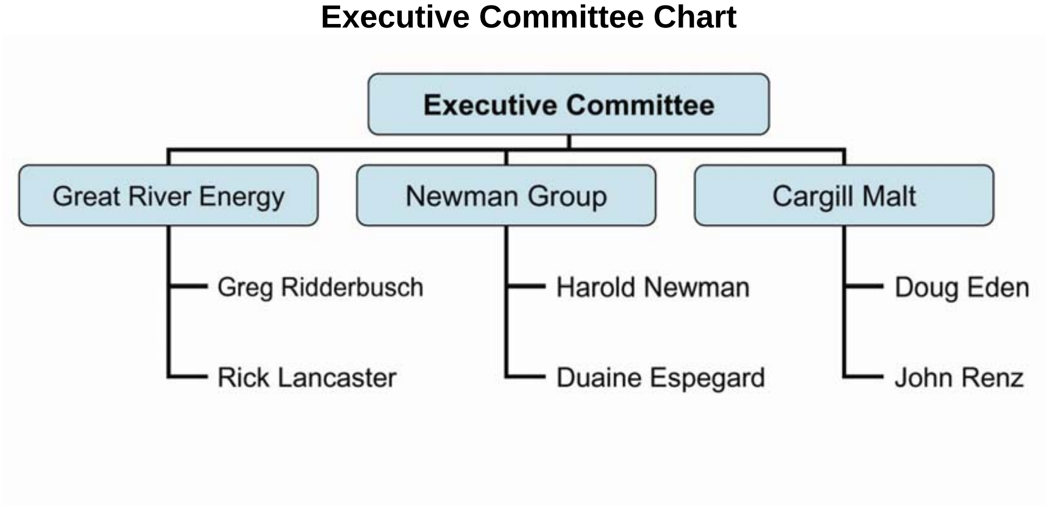
This project will provide new direct and indirect jobs, increase business volume, and provide additional tax revenue. In addition, transmission-system upgrades associated with this project will increase system capacity and stability, which can be the impetus for continued growth in the energy industry and corresponding economic growth within the state.

Preliminary organization charts have been developed for this project. A detailed breakdown of the engineering and construction, finance, partnership development, stakeholder relations, and operations teams can be found above in the Qualifications section.

Project Organization Chart



Executive Committee Chart



Timetable

Project participants have completed feasibility studies and preliminary reviews of permitting requirements, transmission interconnect, and project design of a generating plant and transmission facilities. Commercial operation of Spirit Energy is anticipated for March 2009. A detailed development and construction timetable can be found in Appendix G.

Budget

This request is for $10,000,000 from the North Dakota Industrial Commission to support Spirit Energy's project cost of $157,017,896, which is part of the overall cost of the Spiritwood Energy Park. All grant requests are in today's dollars.

Spiritwood Energy - Capital Cost

Direct Costs - Assigned or Allocated	Total $
Civil	783,395
Boiler Island	$ 63,043,185
Turbine Island	6,890,615
Coal Handling	7,019,641
Controls	1,825,529
Electrical	6,237,635
Construction Indirects	25,424,558
Back Up Boiler	7,650,232
Misc Mech	5,929,117
Cond/Cooling Tower	
Subtotal Direct Costs	124,803,907
Indirect Costs - Allocated By Direct Breakout	
PSD Permitting	50,000
Engineering	3,642,517
Const Management	758,397
SU/Commissioning	314,928
Interest During Construction (IDC)	16,064,041
Spare Parts	642,709
Start Up/Training	257,084
Development Costs	250,000
Insurance	250,000
Contingency	9,984,313
Subtotal Indirect Costs	32,213,989
Total Spiritwood Energy Capital Cost	157,017,896

Matching Funds

The equity partners of Spirit Energy will provide the balance of funding for the project through equity contribution, debt assumption, bonding, and miscellaneous other funding sources. Funds will be provided far in excess of a one-to-one match of grant funds.

I, Douglas Paumen, certify that Great River Energy is not delinquent in any tax liability owed to the State of North Dakota.

Douglas Paumen
Manager, Accounting Services

Confidential Information

Pursuant to Section 54-17.5-06 of the NDCC, Great River Energy requests that the contents of pages 2 through 19 and appendices A through G of our Spirit Energy Power Plant Application be treated as confidential information. This information is proprietary in nature and includes our generation, transmission, environmental and business development strategies. If made public, this information could place Great River Energy at a competitive disadvantage and jeopardize project economics as these strategies are implemented. The DOE/NETL (National Energy Technology Lab) Clean Coal Power Initiative (CCPI) Lignite Fuel Enhancement Project has 4 patents pending approval and information included in this application is sensitive to the business related to the patents.

In addition, Great River Energy requests that all results of our grant application be treated as confidential information under the section of the NDCC previously referenced, unless specifically released by Great River Energy. Again, this information is proprietary and must be kept confidential to ensure Great River Energy's strategies and costs are not released to competitors in the industry.

Appendices

APPENDIX A

BACKGROUND INFORMATION

Includes the following:

- 2005 Great River Energy Annual Report –see attached brochure
- Fitch Credit Rating

NEW YORK--(BUSINESS WIRE)--June 23, 2006--Fitch upgrades Great River Energy Cooperative (MN)'s (GRE) implied senior secured rating to 'A-' from 'BBB+'. The rating outlook is Stable. GRE has approximately $1.2 billion of outstanding debt.

GRE's rating upgrade reflects improved operating results and Fitch's increased comfort over time with the stability, performance, and level of management risk associated with Split Rock Energy (SRE), GRE's power trading subsidiary. Fitch also notes GRE's favorable position within MISO as a result of the location and diversity of its generating resources and its ownership in regional transmission assets. Additionally, GRE has further benefited from the asset optimization and risk management expertise at SRE.

The primary underpinnings for the rating include:

-- a strong and diverse service territory;

-- low-cost baseload generating resources that continue to be among the most efficient in the region (Coal Creek Station in particular);

-- contracts that were extended to 2045 with all 28 member cooperatives;

-- a very strong and experienced management team; and

-- the benefits of an automatic monthly Power Cost Adjustment clause.

Additional support for the rating is provided by strong sales growth (4.6% CAGR over the last five years), the financial strength of the member cooperatives, and a favorable member revenue base comprised of residential (67.3%) and commercial / irrigation (32.7%).

Credit concerns include a large capital plan to primarily fund new generation capacity ($3.5 billion through 2016) and the projected rise in wholesale rates from 4.5 cents / kWh currently to over 7.0 cents /

kWh in 2016. It should be noted that GRE's wholesale rates have generally been approximately 10% below those of other regional providers and Fitch expects that given the great need for additional capacity in the upper Midwest, other regional providers will see their rates rise as well.

Debt service coverage (DSC) as calculated by Fitch (which excludes margins from SRE) was 1.10 times (x) in 2005, an improvement from the 0.95 to 1.08x range of 2001 - 2004. Management expects to budget DSC of 1.10x going forward. Liquidity of 19 days cash on hand is supplemented by available lines of credit, providing a total available liquidity as of Dec. 31, 2005 of 48 days of operations. Fitch is comfortable with liquidity levels and GRE's use of its automatic monthly power cost adjustment clause, which provides sufficient mitigation of potential cost volatility at the 'A-' rating level.

GRE is a generating and transmission cooperative providing wholesale electric energy and related services to 28 member distribution cooperatives, serving over 614,000 customers. GRE is the fourth largest G&T cooperative in the United States and is the second largest wholesale power provider in Minnesota. GRE had total revenue of $691 million and total energy sales of 11,150,000 MWh in 2005.

APPENDIX B

LETTER OF COMMITMENT

The equity partners of Spiritwood Energy Park are fully committed to fund their estimated cost associated with the Lignite Vision 21 Power Plant Project.

<u>July 3, 2006</u>
Date:

<u>GREAT RIVER ENERGY</u>
Name of Proposer

____
Signature of Representative

Greg Ridderbusch
Vice President, Business Development
Typed Name: Title
Authorized Representative

APPENDIX C

RESUMES – Principal Investigators & Key Personnel

Includes biographies or resumes for the following personnel:

- Richard Lancaster
- Greg Ridderbusch
- Andy Stewart
- Mark Strohfus
- Susan Brooks
- Mark Fagan
- Diane Stockdill
- Charlie Bullinger

RICHARD R. LANCASTER

Experience

Vice-president, Generation, Great River Energy, July 2005 to present.

Responsible for the operation and maintenance of 2500 megawatts of electric generation facilities, including two coal-based power plants, two large gas-based peaking plants, a refuse-derived fuel plant, and four oil-fired peaking plants. Responsible for the development and construction of new power plants for a growing electric cooperative.

Vice-president, Corporate Services. Great River Energy. March 2002 to July 2005.

Responsible for executive direction of six departments: Administrative Services, Communications, Environmental Services, Government Affairs, and Demand-side Management/Member Service, and Resource Planning.

Vice-president, Public Affairs. Great River Energy. January 1999 to February 2002.

Responsible for executive direction of four departments: Communications, Environmental Services, Government Affairs, and Demand-side Management/Member Service.

Director, Public Affairs and Marketing. Cooperative Power. 1997-1998.
Manager, Contracts and Rates. Cooperative Power. 1993-1997.
Executive Secretary. Minnesota Public Utilities Commission. 1990-1993.
Manager, Energy Unit. Minnesota Public Utilities Commission. 1987-1990.
Statistical Analyst. Minnesota Department of Public Service. 1983-1987.
Research Scientist. Minnesota Department of Public Service. 1980-1983.
Statistical Research Analyst. Iowa Department of Social Services. 1976-1978.

Boards of Directors

North Central Electric League Board of Directors member.
Split Rock Energy Board of Governors member.

Education

Master of Public Policy. University of Michigan, Ann Arbor.
Bachelor of Arts. Grinnell College. Economics and history, with honors.
Phi Beta Kappa.

Gregory L. Ridderbusch
Vice President, Business Development and Strategy

Greg Ridderbusch has been Great River Energy's vice president, business development and strategy since August 2005. This position is responsible to provide strategic leadership in the evaluation, development, and operation of new business opportunities, and to support the corporate strategic and business planning processes, to benefit members and support the growth objectives of Great River Energy.

Ridderbusch was previously a Utility Management Consultant serving cooperatives, municipals, and investor owned utilities across the United States. His expertise focused on serving executive management teams and governance groups in the area of strategy, business analysis, business planning, financial analysis, technology strategy, and customer marketing.

Ridderbusch was also previously a development engineer developing industrial process equipment for heavy industry. He worked at the DOE Clean Coal technology center and for Thermo Electron's Tecogen cogeneration and research and development division.

Early in his career, Ridderbusch served as an Engineer Officer in the United States Army, in both leadership and staff positions and responsible for the execution of engineering missions including the construction of theater of operations infrastructure.

Ridderbusch has a Master of Business (Finance and Marketing) from J.L. Kellogg Graduate School of Management, Northwestern University, Chicago, IL; a Master of Science (Mechanical Engineering) from the Georgia Institute of Technology, Atlanta, GA; and a Bachelor of Science (Engineering) from the United States Military Academy, West Point, NY.

Andrew Stewart

Project Manger
Great River Energy

Education Bachelor of Science - Civil Engineering, 1979, University of North Dakota
Bachelor of Science – Chemistry, 1978, University of North Dakota

Affiliations Registered Professional Engineer - North Dakota and Minnesota
American Coal Ash Association, Chairman of the Board (1994-1997)
European Association for Use of the By-Products of Coal-Fired Power Stations, Honorary Life Member
American Society of Civil Engineers, Member
American Society of Testing and Materials, Member
University of North Dakota Engineering Alumni Advisory Group, Member

Experience

2006–Present **Great River Energy** **Elk River, MN**
Project Manager, Generation Development
Professional engineer with over 20 years of experience in energy/power generation and civil engineering environments. Responsible for the development and management of new generation projects.

2001–2006 **Power Products Engineering, Inc.** **Eden Prairie, MN**
Owner and President
Professional engineer with over 20 years of experience in energy/power generation and civil engineering environments. Customer-focused and attuned to markets and business objectives. Outstanding technical abilities enhanced by proven skills as a project manager, negotiator and team leader. Grounded in plant operations and construction, with special expertise in the development of energy projects.

Clients include: NRG Energy, Electicite de France(EDF), Great River Energy, The Falkirk Mining Company, American Coal Council, Consulting Engineers Group, Energy and Environmental Research Center, and Dakota Electric Association

2001–2006 **Golder Associates, Inc.** **Denver, CO**
Senior Consultant
Providing senior level consulting services to Golder Associates on a variety of engineering projects.

1998 – 2000 **En-Rock, Inc.** **Eden Prairie, MN**
President
Responsible for the development, coordination and monitoring of the by-product programs from coal fired power plants. Duties consist of sales and marketing of fly ash, scrubber gypsum and bottom ash from various utilities and customers producing these by-products. Other areas of responsibility include providing engineering services in the use of by-products as well as management consulting in the area of disposal of unused by-products.

1981 – 1998 **Cooperative Power Association** **Eden Prairie, MN**
Manager of Engineering Services

A wholesale electrical power supply cooperative serving member utilities in west central and southern Minnesota. Operating an 1100-megawatt coal-fired power plant in Underwood, ND and a 50-megawatt gas turbine in St. Bonifacious, MN.

Led engineering department of 17 responsible for the construction of generation, transmission, substation and telecommunication projects, with additional responsibility for fuels management. Oversaw projects valued at $15 million annually.

Also responsible for the development, coordination and monitoring of the by-product program for Coal Creek Station. Program consists of sales of flyash and bottom ash with a net benefit of over $2 million annually. New product development includes the addition of bottom ash sales in 1997 and the upcoming gypsum conversion facility outlined below.

1975 – 1981 **Richmond Engineering, Inc.** **Grand Forks, ND**

Engineer

A privately held provider of design and construction management services for municipal, state and federal civil works projects.

Design and construction of a $5 million upgrade to a city water plant; design and management of a flood repair project for a medium-sized city; construction management of a water storage facility; numerous highway projects.

PROJECT RELATED EXPERIENCE

Great River Energy

Assisted Great River Energy on the civil and project management portion of the proposal to Rock-Tenn for a Waste to Energy Plant located in St. Paul. (2006)

Greenway Consulting, LLC

Assisting Greenway on the civil and design portion of Ethanol Plants at various locations. (2005)

Great River Energy

Assisted Great River Energy on the civil and design portion of the Blue Flint Ethanol Plant located adjacent to Coal Creek Station. (2005)

NRG Energy

Coordinated contract negotiations with a variety of vendors to perform turbine outage maintenance with a value of $1 billion. Coordinated negotiations of a Master Purchase Agreement with Pratt & Whitney Power Systems, Inc. for Peaking Turbines. Coordinated a variety of turbine purchase contracts with General Electric and Siemens Westinghouse. Negotiated a Master Services Agreement with General Electric for maintenance of the NRG fleet of 7FA turbines. Initiated discussions with Siemens Westinghouse on a Long Term Maintenance Program for NRG’s fleet of V84.3A(2) gas turbines. (June 2001 to September 2002)

Electricité de France (EDF)

Responsible for producing a report titled “MARKET STUDY FOR THE ASHES TO BE PRODUCED FROM FLUIDIZED BED COMBUSTION BOILERS IN GUADELOUPE” for the purpose of providing an evaluation of CCP market in the Caribbean region for EDF. The market assessment included export opportunities for a variety of CCP products and the economics associated with each product to other Caribbean islands as well as into Florida. (2001)

Great River Energy

Assisted Great River Energy on the civil installation portion of Pleasant Valley Station Unit 13, a Siemens Westinghouse W501D5A combustion turbine. (2001)

Golder Associates - Great River Energy

Senior consultant for construction of a $1 million ash disposal facility closure and expansion. (2001)

Coal Creek Station

Performed economic analysis, gained management and Board approval, and negotiated contract terms for the purchase and installation of a $33.75 million turbine generator upgrade for Coal Creek Station. Coordinated input, agreement and buy-in from multiple parties. (1998)

Coal Creek Station

Project manager for construction of a $3.8 million gypsum conversion facility at Coal Creek Station. Project involved original laboratory and pilot scale testing program. Obtained a $1 million grant for facility construction hired design firm and coordinated construction. (1998)

Ash Disposal Facility

Project manager for the construction of a $5 million ash disposal facility, involving all aspects of permitting, design and construction. (1996)

Coal Creek Station

Coordinated the purchase of $3 million worth of turbine upgrades for Coal Creek Station Unit 1. Coordinated the negotiation of a contract to perform all of the turbine outage maintenance as a lump sum contract worth $2 million, resulting in saving ten days of outage time valued at $700,000. (1995)

Ash Disposal Facility

Project manager for construction of a $.5 million ash disposal facility, involving a complete process for facility construction, including permitting, design and construction. (1994)

Coal Creek Station

Project manager for the design and construction of a $42 million wastewater storage pond and solid waste disposal system, consisting of the permitting, design and construction of 350 acres of lined storage ponds at Coal Creek Station. (1989 - 1992)

PUBLICATIONS

"The Value of Coal Combustion Products: An Economic Assessment of CCP Utilization for the US Economy"
American Coal Council, April 2005

"Evaluation of Physical Properties and Engineering Performance of CCB's in the Laboratory and the Field"
OSM Meeting, April 2002

"Coal Creek Station Auxiliary Cooling Waterline Repair"
Power-Gen 96

"Coal Creek Station Pond Liner Modifications"
ASCE Energy Conference

"Changing Industry and the New Importance of CCB Use"

ACAA Twelfth International Symposium on Management and Use of Coal Combustion By-Products

"Present Status and Future Initiatives Regarding Coal Ash Utilization in the United States"
1996 International Clean Coal Technology Symposium on Coal Ash Utilization, Tokyo, Japan

Mark Strohfus

Experience

Environmental Project Leader, Great River Energy, July 2005 to present.

Responsible for: coordinating the application, processing, and issuance of all environmental permits and approvals for Great River Energy's generation projects; recommending alternative environmental strategies to facility the implementation of generation projects; providing technical analysis of greenhouse gas mitigation strategies.

Environmental Policy Analyst, Great River Energy. June 1999 to July 2005.

Responsible for: supporting the development of environmental rules and regulations that are practicable and implementable by Great River Energy; managing Great River Energy's mercury science and control technologies research; analyzing the latest research and development in the area of environmental and health impacts associated with various environmental exposures.

Environmental Consultant. Earth Tech, Inc. November 1993 to June 1999
Environmental Consultant. Delta Environmental Consultants, June 1990 to November 1993
Environmental Consultant. Earth Tech, Inc. March 1987 to June 1990

Responsible for assisting clients in complying with environmental requirements including those that applied to air emissions, wastewater discharges, storage tanks, and hazardous and non-hazardous wastes.

Education

Bachelor of Science. University of Minnesota, Process Engineering - Paper Science

Susan E. Brooks

Sbrooks@Grenergy.com
763-241-2233

EXPERIENCE

Manager of Finance 2006 to present
Great River Energy, Elk River, MN
Responsible for planning, leading and coordinating the finance function including financing, treasury, financial forecasting, risk management, insurance, and internal audit for this $713 million revenue electric generation and transmission utility.

Consultant, Minneapolis, MN 2003 to 2005
Provided senior level consulting services to American Express Company in the several engagements, including legal, regulatory and compliance requirements process integration, global IT metrics identification and reporting, and IT Division financial management optimization.

Vice President, Corporate Development 2000 to 2001
U.S. Bancorp, Minneapolis, MN
Identified product and market growth opportunities via acquisitions for units of this $84 billion asset bank. Led cross-functional teams and directed the development of detailed valuation models and pricing recommendations, due diligence investigations, transaction negotiations, and integration activities.

Finance Director, Commercial Services 1999 to 2000
U.S. Bancorp, Minneapolis, MN
CFO for the Commercial Services business line, a $4.2 billion asset division with 2000 employees.

Business Line Controller, Properties and Security 1998 to 1999
U.S. Bancorp, Minneapolis, MN
Managed the finance function for the $650 million asset facilities business unit.

Controller 1997 to 1998
Pinnacle Finance Company, Minneapolis, MN
Created general financial control and treasury functions for this start-up consumer finance company.

Manager of Finance 1996 to 1997

U.S. Bancorp (formerly First Bank Systems), Minneapolis, MN
Managed the finance function for Credit, Finance, Legal and Human Resources support units, representing 1300 employees.

Old Dominion Electric Cooperative, Glen Allen, VA 1984 to 1995
Established the financial planning, treasury, insurance and accounts receivable functions for this newly operational electric generation company which grew to $350 million sales.

Manager of Finance (1989 to 1995)

Financial Analyst (1986 to 1989)

Economist (1984 to 1986)

Analytic Services, Inc., Arlington, VA 1982 to 1983

Research Analyst

EDUCATION

Master of Business Administration, College of William and Mary, Williamsburg, VA
B.A. in Economics, Virginia Polytechnic Institute and State University, Blacksburg, VA

MARK GREGORY FAGAN
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EDUCATION: *University of Minnesota; Minneapolis, MN*

Hubert H. Humphrey Institute of Public Affairs
Master of Science, May 2006
Thesis Topic: "Ethanol Mandates: an Analysis of Policies and Viabilities"
Major: Science and Technology Policy
Cumulative GPA: 3.676

Dakota Wesleyan University; Mitchell, SD
Bachelor of Arts, Summa Cum Laude, May 1996
Major: Biology
Minors: Chemistry and Sociology
Cumulative GPA: **3.958**

EXPERIENCE: *Great River Energy – Business Development & Strategy, Elk River, MN*

Manage of Business Development
April 2006 – Present

Great River Energy – Generation Services, Elk River, MN
Generation Optimization Planner
December 2002 – April 2006

Great River Energy – Resource Planning, Elk River, MN
Market and Pricing Analyst
November 2000 – December 2002.

Great River Energy – Demand Side Management, Elk River, MN
Pricing & Contracts Administrator
June 1999 – November 2000.

TRAINING: "Energy Risk Management Series" – EPRI; **March & May 2004.**

"Project Management courses" - University of St. Thomas; **May 2003.**

"Econometrics for the Business Analyst" – NABE; **October 2002.**

MEMBERSHIPS: **Split Rock Energy, LLC**
Member of Risk Management Committee
2001 - Present

National Association for Business Economics
2002 – Present.

United States Association for Energy Economics
2001 – Present

Diane Stockdill

Diane Stockdill, Leader of Environmental and Plant Services at Great River Energy's Coal Creek Station, has over twenty-five years of professional experience in the power industry. Ms. Stockdill's experience includes specialization is regulatory review, environmental compliance and permitting. Ms. Stockdill is a graduate of North Dakota State University.

Charlie Bullinger

Charlie is currently Senior Principle Engineer. He has held several positions during is 29 year tenure in the power industry. Most recently led the engineering group for 12 years at an 1100 MW lignite fired generating station. His current focus in new technology, government projects, and EPRI technological liaison.

Experience:

Jan. 1999 – Present	Engineering Services Leader, Great River Energy Coal Creek Station (Underwood, ND)
Jul. 1994 – Jan. 1999	Engineering Services Leader, Cooperative Power Coal Creek Station (Underwood, ND)
Aug. 1991 – Jul. 1994	Performance Engineering Supervisor, Cooperative Power, Coal Creek Station (Underwood, ND)
Nov. 1986 – Aug. 1991	Results Engineer, Cooperative Power, Coal Creek Station (Underwood, ND)
Nov. 1980 – Nov. 1986	Planner-Scheduler, Cooperative Power, Coal Creek Station (Underwood, ND)
Mar.1977 – Nov.1980	Systems Engineer, Cooperative Power, Coal Creek Station (Underwood, ND)
May 1976 – Mar. 1977	Test Technician, Energy Research Center, DOE, (Grand Forks, ND)

Education:

Sep. 1969 – May 1975	Bachelor of Science – Mechanical Engineering, North Dakota State University (Fargo, ND)

Professional Memberships & Certifications:

American Society of Mechanical Engineers
Member # 156018, 25 years

Registered Professional Engineer
State of North Dakota # PE – 3773
State of Minnesota # 24364

ACRONYMS

AQRV	Air Quality Related Value
AQCS	Air Quality Control System
BACT	Best Available Control Technology
BMPs	Best Management Practices
BTU	British Thermal Unit
CAA	Clean Air Act
$CaCO_3$	Calcium carbonate
CAS	Chemical Abstract Services
$CaSO_4$	Calcium sulfate
CAMR	Clean Air Mercury Rule
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
DOE	Department of Energy
EHS	Environmental Health & Safety
ESP	Electrostatic precipitator
FAA	Federal Aviation Administration
FF	Fabric Filter
FGD	Flue Gas Desulphurization

FLAG	Federal Land Managers’ Air Quality Related Values Work Group
GRE	Great River Energy
H_2SO_4	Sulfuric Acid
HAP	Hazardous Air Pollutants
HCl	Hydrochloric acid
Hg	Mercury
ICR	Information Collection Request
LLC	Limited Liability Corporation
LRC	Lignite Research Council
MACT	Maximum Achievable Control Technology
MW	Megawatt
NDAC	North Dakota Administrative Code
NDPDES	North Dakota Pollutant Discharge Elimination System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NO_X	Nitrogen Oxides
NAAQS	National Ambient Air Quality Standards
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
OSHA	Occupational Safety and Health Administration
PAC	Powder Activated Carbon
PM	Particulate Matter

PSD	Prevention of Significant Deterioration
PSM	Process Safety Management
RMP	Risk Management Program
SDA	Spray Dryer Absorber
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SWPPP	Storm water pollution prevention plan
TMDL	Total Maximum Daily Load
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

FUNCTIONAL STUDY AREAS—DETAILS

Environmental

Spiritwood Industrial Park will be a new $350-million industrial complex near Jamestown, North Dakota that will include a new 100-million-gallon ethanol plant, an expanded Cargill malt-processing plant, and a 80-megawatt-equivalent lignite-coal-fired combined heat and power (CHP) plant. This section of the report focuses on the environmental permitting requirements applicable to the CHP plant.

Proposed Combined Heat and Power Plant

Ownership of the Spiritwood Energy CHP plant will be a joint venture between Great River Energy, the Newman Group, and Cargill. The Newman Group will own 41%, GRE will own 40%, and Cargill will own 19%. Each partner will be required to invest cash equity into Spiritwood Energy. The joint venture will likely be a limited liability corporation ("LLC"). The by-laws of the LLC will require the three partners to work cooperatively and, hence, from a governance standpoint, one partner will equate to one vote. The LLC will enter into separate life-of-plant contracts with the Newman Group and Cargill for process steam and with GRE for power and electric energy. GRE will operate and maintain the CHP plant under an agency agreement with the LLC.

The 80-megawatt-equivalent coal-fired steam-generating plant will use about 600,000 tons of lignite coal from the Falkirk Mine annually. The CHP main boiler will be an atmospheric, circulating fluidized bed firing dried lignite with a heat input capacity of 910 MMBtu/hr. The lignite will be dried at GRE's Coal Creek Station. The gross output of the CHP will be 35-50 MWe, of which 34 MWe will be contracted electricity delivered to the grid; the balance will be used in the operation of the CHP plant. The plant will generate 690,000 lb/hr of steam; 394,000 lb/hr will be contracted process steam to the ethanol plant, and 200,000 lb/hr will be contracted process steam to the malting plant. The balance of the steam produced will be used for feed-water heating.

In addition to the main boiler at the CHP plant, there will be three natural-gas/propane-fired auxiliary boilers each with a heat input capacity of 220 MMBtu/hr and three diesel engines for the back-up boiler feed-water pump, the emergency fire pump, and the back-up generator set; and the storage and handling of coal, lime, limestone, ash, and activated carbon.

Power Plant Environmental Permitting Background

The Spirit Power project will be subject to environmental permitting requirements that must be closely tracked and managed during the planning and construction phases. Table 2-5-1 provides a list of environmental permits that are typically required for a new CHP facility. Both state and federal regulations control air emissions, effluents, and solid waste discharged from the CHP plant. Additional environmental regulations may apply on a site-specific basis (e.g., National Environmental Policy Act, National Historic Preservation Act, endangered species, etc.); however, these have not been evaluated at this point.

The North Dakota Department of Health, Division of Air Quality (NDDHAQ) is responsible for issuing air pollution control permits for North Dakota and for making regulatory decisions. The proposed CHP plant will be permitted as a new major source of air pollution and will need to comply with several air pollution control programs.

The North Dakota Department of Health, Division of Water Quality (NDDHWQ) is responsible for issuing NPDES permits for North Dakota. The State Engineer administers water appropriations and rights.

Table 2-5-1
Typical Environmental Permitting Requirements

Permit or Approval	Responsible Agency	Regulated Activity
NSR-PSD Air Construction Permit	State	Construction of major source of air pollution
Phase II Acid Rain Permit	USEPA/State	Operation of an affected source under Phase II of the Acid Rain Program

Permit or Approval	Responsible Agency	Regulated Activity
CAA Title V Operating Permit	State	Operation of a significant source of air pollution (generally issued after the construction permit and after the source has begun operation)
Certification of Continuous Emission Monitoring System (CEMS)	USEPA/State	Operation of CEMS in compliance with Title IV of the CAA – Acid Rain Program
Determination of Obstruction Hazard	Federal Aviation Administration	Construction of tall structures
Wastewater Facility Construction Approval	State	Construction of wastewater treatment equipment (e.g., oil separator)
NPDES Permit	State	Discharge of wastewater to surface waters
NPDES Storm Water General Permit for Construction	State	Storm water runoff from construction areas
NPDES Storm Water General Permit for Operational Site	State	Storm water runoff from operating plant site
Groundwater Protection Permits	State	Construction and operation of on-site waste holding ponds and waste disposal facilities
Conditional Water Permit/Water Rights	State	Appropriation and beneficial use of state waters
Construction in a Navigable Waterway or Wetland	USACE/State	Construction of a water storage reservoir or intake structure
Solid Waste Disposal Permits	State	Construction and operation of on-site solid waste disposal facilities
Oil Tank Construction Permit	State Fire Marshal	Construction of storage tank for diesel oil or other petroleum liquids
Septic Tank Construction Permit	County	Construction of septic tanks

Air Pollution Control and Construction Requirements

State Emission Standards

The CHP plant will be required to comply with state emissions and permitting standards, pursuant to North Dakota Administrative Code (NDAC) Article 33-15. The plant will also be subject to federal New

Source Performance Standards, National Emission Standards and New Source Review requirements, incorporated by reference in the state standards, which are discussed in detail below.

New Source Performance Standards

Electric Utility Steam Generating Units 40 CFR Part 60 Subparts Da, Db, Dc

The CFB boiler will be required to comply with New Source Performance Standards (NSPS), which establish emissions standards for electric utility steam-generating units. There are two important points to consider: 1) different NSPS requirements exist for utility-sized boilers (dependent on heat input capacity), and 2) the USEPA recently issued proposed NSPS revisions that would apply to any project constructed after February 28, 2005, even though the rules are not yet finalized.

On February 28, 2005, USEPA proposed amendments to the current NSPS for utility, industrial, commercial, and institutional steam generation units. The proposed amendments would include:

- Emission standards for particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) from Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da), which are those units with a heat input capacity greater than 250 MMBtu/hr. Cogeneration units that supply more than one-third of their potential electric output capacity and more than 25 MW output to a utility power distribution system for sale, are considered electric utility steam generating units subject to this subpart.

- PM emission limits for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Db), which are those with a heat input capacity of less than 250 MMBtu/hr but greater than 100 MMBtu/hr.

- PM emission limits for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Dc), which are those with a heat input capacity of less than 100 MMBtu/hr but greater than 10 MMBtu/hr.

Units that begin construction, modification or reconstruction after February 28, 2005 are affected by the proposed amendments.

The proposed emission limits for new electric utility steam-generating units, applicable to the proposed CFB boiler, are:

- 6.4 ng PM/J (0.015 lb/MMBtu) heat input regardless of fuel being burned.
- 250 ng SO_2/J (2.0 lb/MWh) gross energy output, regardless of fuel being burned (one exception applies to units that burn over 90% coal refuse). This corresponds to a limit of 0.58 lb/MMBtu SO_2.
- 130 ng NO_x /J (1.0 lb/MWh) gross energy output, regardless of fuel being burned. This corresponds to a limit of 0.30 lb NOx/MMBtu.

The proposed output-based emission limit for SO_2 would replace both the current percentage reduction requirement and the input-based emission limit. For combined heat and power applications, energy output is the sum of the gross electrical output and the useful energy of the process steam, with useful energy of the process steam calculated as 50% of the thermal output. Compliance with the proposed limits would be determined using the same testing, monitoring, and other compliance provisions in the existing rule. New utility steam-generating units must demonstrate compliance with NSPS emission standards on commercial start-up and are required to have continuous emission monitoring systems.

Three natural-gas/propane-fired auxiliary boilers, each rated at approximately 200 MMBtu/hr, will be operated to provide saturated steam during shutdowns of the CFB boiler during forced and scheduled outages. The auxiliary boilers will be required to comply with the Subpart Db NSPS requirements for industrial-commercial-institutional steam generating units. The current NSPS rule specifies only NO_x emission limits for natural gas-fired boilers. With a low heat-release rate (<70,000 BTU/hr-ft^3), the NO_x limit is 0.10 lb/MMBtu, and with a high heat-release rate, the NO_x emission limit is 0.20 lb/MMBtu.

The proposed PM emission limit for industrial-commercial-institutional steam-generating units is 13 ng/J (0.03 lb/MMBtu heat input) for units that burn coal, oil, wood, or a mixture of these fuels with other fuels. Since the auxiliary boilers will only be fired using natural gas or propane, the proposed PM emission limit will not be applicable.

Coal Preparation Plants 40 CFR Part 60 Subpart Y

The CHP plant will be required to comply with the Subpart Y NSPS requirements for coal preparation plants. The provisions of this subpart are applicable to affected sources that process more than 200 tons of coal per day and use coal processing and conveying equipment (including breakers and crushers), coal storage systems and coal transfer and loading systems. Emissions from these coal-handling sources must exhibit opacity of less than 20%.

Utility MACT Standards/Clean Air Mercury Rule

The USEPA issued the Utility Mercury Reductions Rule, also known as the Clean Air Mercury Rule (CAMR), on March 15, 2005. It integrated new mercury reduction requirements into the NSPS Subpart Da provisions. The USEPA revised the regulatory finding made in December 2000 and set standards of performance pursuant to Section 111 of the Clean Air Act (CAA) for mercury emissions from new coal-fired units and initiated a mercury cap-and-trade program for both new and existing coal-fired generating units.

For each coal-fired electric utility steam-generating unit constructed after January 30, 2004, no gases which contain mercury (Hg) emissions in excess of the Hg emissions limit shall be discharged. For coal-fired steam generating units that burn only lignite, part 60.45Da(a) states the discharge shall not contain Hg in excess of 145×10^{-6} lb/MWh or 0.145 lb/GWh on an output basis. When a cogeneration unit is being used, the emission rates shall be based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

These emission standards apply at all times except during periods of start-up, shutdown, or malfunction. The Hg emission rate is to be calculated using hourly Hg concentrations measured according to the emission monitoring requirements set forth in part 60.49Da. Compliance with the emissions requirements is determined on a 12-month rolling average basis. Part 60.49Da states that a continuous emissions monitoring system (CEMS) must be installed to measure and record the concentration of Hg in the exhaust gases.

Industrial Boiler MACT Standards

The USEPA published the final MACT rule for industrial, commercial and institutional boilers in 40 CFR Part 63 Subpart DDDDD. The MACT rule applies to boilers located at facilities that are major sources of hazardous air pollutants (HAPs). Pursuant to part 63.7491, a cogeneration unit that supplies more than one-third of its potential electric output capacity, and more than 25 MW output to a utility power distribution system for sale, is an electric utility steam generating unit that is exempt for the Industrial Boiler MACT requirements. Since the CHP plant meets this definition, the plant will not be subject to the Industrial Boiler HAP emission limits.

New Source Review Requirements

Air quality construction permits issued pursuant to the New Source Review (NSR) regulations frequently establish more stringent requirements for specific projects than either state emission limits or NSPS. NSR requirements are applied to certain large projects. In the case of the proposed CFB boiler, there would effectively be a two-step threshold analysis. NSR would apply if either of the following two conditions were true:

- The heat input capacity of the CFB boiler is greater than 250 MMBtu/hr and the total annual emissions of any criteria air pollutant is greater than 100 tons/year, or
- The heat input capacity of the CFB boiler is less than 250 MMBtu/hr and the total annual emissions of any criteria air pollutant is greater than 250 tons/year.

For the size boiler under consideration (approximately 700 MMBtu/hr), the proposed fuels and the proposed emission control equipment, the emissions of several pollutants would be more than 100 tons/year, but less than 250 tons/year. Based on a heat input capacity of 700 MMBtu/hr and estimated annual emissions, NSR regulations would apply to the project.

Best Available Control Technology

The proposed CHP plant will be permitted as a new major source of air pollution that will be located within an area that is designated as attainment for all criteria pollutants. A project that is subject to the NSR program's Prevention of Significant Deterioration (PSD) requirements is required to control emissions using the Best Available Control Technology (BACT). BACT is proposed by the applicant and determined on a case-by-case basis by the NDDHAQ during issuance of the air quality construction permit. BACT is generally defined as the maximum degree of pollutant reduction achievable, taking into account energy, environmental and economic impact.

Although it is not possible to predict exactly what will be required as BACT for any particular project, recent BACT determinations provide an indication of likely requirements. Table 2-5-2 provides a summary of recent PSD-BACT determinations for CFB boilers. Table 2-5-2 includes units fired on bituminous coal, lignite and petroleum-coke, and provides a starting point for establishing BACT emission requirements for any new CFB electric generating station. Most of the recent CFB BACT decisions, however, are for considerably larger CFB boilers.

Table 2-5-2
Recent PSD-BACT Determinations for CFB Boilers

Pollutant	Typical BACT Control Technology	Typical BACT Emissions Limit	Typical BACT Control Efficiency
Nitrogen Oxides (NO_x)	CFB combustion and SNCR	0.07 to 0.09 lb/MM/Btu	SNCR with 40 – 60% efficiency

Pollutant	Typical BACT Control Technology	Typical BACT Emissions Limit	Typical BACT Control Efficiency
Sulfur Oxides (SO_x)	CFB combustion with limestone injection	0.10 to 0.12 lb/MMBtu	>94% control efficiency based on worst-case design fuel
Opacity	Fabric Filter	10% Opacity*	99.9%
Particulate Matter (PM_{10})	Fabric Filter	0.010 to 0.015 lb/MMBtu (PM_{10} – filterable)	>99.5% PM_{10}
Carbon Monoxide (CO)	Combustion Control	0.10 to 0.15 lb/MMBtu	N/A
Volatile Organic Compounds (VOC)	Combustion Control	0.003 to 0.005 lb/MMBtu	N/A

*May emit 27% opacity for one 6-minute period per hour

A recent North Dakota permit for a similar sized CFB boiler included the BACT emission limits defined in Table 2-5-3:

Table 2-5-3
Reference BACT Emissions Limits

Pollutant	Control Technology	Emission Limit
Sulfur Dioxide (SO_2)	Limestone Injection (90%)	0.09 lb/MMBtu (30-day rolling average)
Nitrogen Oxides (NO_x)	SNCR	0.10 lb/MMBtu (30-day rolling average)
Particulate Matter (PM10 – filterable)	Fabric Filter	0.02 lb/MMBtu (3-hour average)
Total PM_{10} (filterable and condensable)	Fabric Filter	0.48 lb/MMBtu (3-hour average)
Carbon Monoxide (CO)	Combustion Control	0.11 lb/MMBtu (3-hour average)
Volatile Organic Compounds (VOC)	Combustion Control	0.0035 lb/MMBtu (3-hour average)
Sulfuric Acid Mist (H_2SO_4)	Limestone Injection	No limit
Mercury (Hg)	No Additional Controls	No limit

Based on the foregoing and as discussed in detail in Section 2-5-3, proposed control technologies and emission limits for the CHP plant are listed in Table 2-5-4:

Table 2-5-4
Proposed CHP Plant BACT Emissions Limits

Pollutant	Control Technology	Permit Emission Limit
Sulfur Dioxide (SO_2)	CFB Combustion and Limestone Injection and Spray Dryer Absorber (design rating at 97% removal efficiency)	0.09 lb/MMBtu (30-day rolling average), and NSPS output limit of 2.0 lb/MWh
Nitrogen Oxides (NO_x)	CFB Combustion and SNCR (design rating at 0.08 lb/MMBtu emissions)	0.09 lb/MMBtu (30-day rolling average), and NSPS output limit of 1.0 lb/MWh
Particulate Matter (PM10 – filterable)	Fabric Filter (design rating at 0.015 lb/MMBtu)	0.015 lb/MMBtu (3-hour average)
Total PM_{10} (filterable and condensable)	Fabric Filter	0.475 lb/MMBtu (3-hour average)
Carbon Monoxide (CO)	Combustion Control	0.11 lb/MMBtu (3-hour average)
Volatile Organic Compounds (VOC)	Combustion Control	0.0035 lb/MMBtu (3-hour average)
Mercury (Hg)	Powdered Activated Carbon Injection	0.145 lb/GWh
Sulfuric Acid Mist (H_2SO_4)	Limestone Injection & Fabric Filter	No limit

PSD Increment Analysis

The PSD regulations also limit the incremental increase in concentration (ug/m^3) of criteria pollutants that may be emitted into the ambient air (PSD increments). Therefore, during the permitting process, the applicant must analyze by computer modeling the impacts that emissions from the new source may have on the ambient air quality and determine whether the PSD increments that are established for attainment areas are exceeded. Occasionally, this analysis may drive further reductions in permitted emissions, but this outcome is not expected for the Spirit Energy case. Screening level modeling early in the project planning stage can identify potential ambient air quality impacts/issues and determine if on-site pre-monitoring of baseline ambient conditions will be required.

Class I Area Program Requirements

The NSR-PSD rules require the permitting agency to determine whether emissions from a proposed plant will have an adverse impact on visibility and other air quality related values at Class I areas. Class I areas include national parks, wilderness areas, and wildlife refuges. The Clean Air Act also mandates that Federal Land Managers protect the air quality related values, including visibility, in Class I areas. Recently, assessing potential impacts on Class I areas has become more challenging. Guidance issued by the Federal Land Managers' Air Quality Related Values Work Group (FLAG Guidelines) has made the analysis process, and the involvement of the Federal Land Managers, significantly more rigorous in the last several years.

Frequently, air quality considerations for Class I Areas in the project region could mandate emission limits more stringent than BACT, in order to demonstrate in the analysis that the plant would not have an adverse impact on visibility. Specifically, it could be necessary to further reduce emissions of H_2SO_4, SO_2 and possibly NO_x emissions. The nearest Class I areas, the Lostwood National Wildlife Refuge and Theodore Roosevelt National Park, are both more than 300 kilometers distant. Voyageurs National Park, in Minnesota, is more than 400 kilometers distant. Therefore, due to the size of the proposed CFB boiler, the proposed pollution control technologies, and the relatively large distance from the proposed site to the nearest Class I areas, it is not anticipated that emission reductions will be required by Class I area/visibility considerations.

Acid Rain Program Requirements

The CHP plant will be required to participate in the federal Acid Rain Program. Every emissions source affected by the Acid Rain Program must have a permit. Each acid rain permit specifies the Title IV requirements that apply to each affected unit at the affected source. All affected sources must submit acid rain permit applications to a USEPA-approved state or local Title IV permitting authority, which in turn issues and administers the acid rain permit as part of the larger Title V permit. The acid rain permit specifies each unit's allowance allocation, which will be zero, and a NO_x limitation, which will not be applicable to the CHP plant. The permit also specifies compliance plan(s) for the affected source. The project compliance plan will include a requirement to obtain SO_2 allowances in the Clean Air Markets system for each ton of SO_2 emitted each year. All affected units must hold sufficient SO_2 allowances by the allowance transfer deadline to account for SO_2 emissions for each calendar year. This is the only SO_2 compliance option in Phase II of the Acid Rain Program, and is automatically denoted in the acid rain permit application.

Air Quality Permits to Construct

A Permit to Construct is required for any new stationary source, or modification to an existing source. New or modified sources applying for a Permit to Construct must also submit a Hazardous Air Pollutant (HAP) Permit application in compliance with the NDDHAQ Air Toxics Policy, in which risk assessment of carcinogenic and toxic emissions will be evaluated. Construction may not begin before a permit is issued.

The NDDHAQ uses a typical application process, where the application forms are submitted by the applicant and the agency reviews them for completeness. If the application is incomplete, the applicant will be notified of the deficiencies. If the application is complete, the technical review will begin. After review, the Department will issue or deny the permit. A 30-day public comment period is required for the proposed CHP plant. Depending on whether the project is permitted as a major source, or as a synthetic minor source, it can take from four months to one year to obtain a Permit to Construct.

Air Quality Permits to Operate

A Permit to Operate is required for those sources that receive a Permit to Construct. The CHP plant will require both a Title V Permit to Operate and a Title IV Acid Rain Permit. Alternatively, the plant may require a Synthetic Minor Source Permit to Operate, if annual emission limits are practical and accommodate annual production requirements. Sources that receive a Permit to Construct must submit a 30-day notice of the proposed start-up of the facility. A complete Title V application, including Title IV, must be submitted within 12 months of commencing operation.

Continuous Emission Monitoring Systems

Pursuant to NSPS (Part 60), CAMR and Acid Rain (Part 75) regulations, the CHP plant must comply with the installation, certification, operation, and maintenance requirements for continuous emission monitoring systems (CEMS) for SO_2, NO_x, CO_2, Hg and volumetric flow, and for the continuous opacity monitoring system (COMS) on the CFB boiler exhaust stack. A NO_x CEMS is required on the auxiliary boilers combined exhaust stack, unless a parametric operating plan that demonstrates continuous NO_x compliance is submitted and approved.

Federal Aviation Administration Permit Requirements

In accordance with 14 CFR 77, if the project exhaust stack exceeds 200 feet in height or is located within 20,000 feet of an airport, notice to the Federal Aviation Administration (FAA) is required. The CHP plant primary exhaust stack will be a minimum of 200 feet in height.

The notification to the FAA must be submitted at least 30 days prior to the date of proposed construction, using FAA Form 7460-1. Generally, FAA processing of this form takes 3 to 4 months. The FAA will acknowledge, in writing, receipt of Form 7460-1 and, if required, will forward a Form 7460-2, Notice of Actual Construction or Alteration. Part 1 of 7460-2 must be completed and sent to the FAA at least 48 hours prior to starting construction of the stack. Part 2 of 7460-2 must be submitted within 5 days after the structure has reached its greatest height.

The forms require the following information:

- Latitude and longitude of the stack accurate to within the nearest second (or hundredth of a second, if available)
- A copy of a documented site survey with the surveyor's certification stating the amount of vertical or horizontal accuracy in feet, if available
- Preferred marking/painting and/or lighting description

The FAA standards for stack marking and lighting are included in the U.S. Department of Transportation FAA Advisory Circular, AC 70/7460-1K, entitled Obstruction Marking and Lighting.

Water Discharges

Surface Water Discharge – Dewatering

A permit application must be submitted to the NDDHWQ to request inclusion in the North Dakota Pollutant Discharge Elimination System (NDPDES) Temporary Dewatering and Hydrostatic Testing General Permit NDG-07000. The permit provides authorization for operations engaged in temporary dewatering activities to discharge uncontaminated waters from locations in North Dakota to state surface waters. The application must be submitted at least 30 days prior to the anticipated start of the discharge. The NDDHWQ will have 30 days to grant discharge authority, deny authority or request additional information. Permitted discharges must submit notification information 5 days prior to start of discharge and comply with effluent limitations and monitoring.

Due to the shallow groundwater table (groundwater elevation within 8-feet of surface) at the project site, it is anticipated that groundwater dewatering will be necessary during construction (e.g., truck unloading area foundations, underground fire suppression piping, etc.). Authorization to discharge groundwater during the dewatering activities will be required for the project.

Surface Water Discharge – Operational Site

Pursuant to NDAC Article 33-16, an NDPDES permit application must be submitted to the NDDHWQ to discharge wastewater into waters of the state. The NDPDES application must be submitted at least 180 days prior to plant operation or in sufficient time to allow the NDDHWQ to ensure compliance with state and federal requirements. Permitted discharges must comply with water quality standards, total maximum daily loads (TMDL), treatment requirements and effluent limitations. The NDPDES permitting process may take six to twelve months depending on public comments, appeals and time required to respond to comments.

CHP plant wastewaters will be comprised of reverse osmosis reject water, boiler blowdown, plant drains from an oil-water separator, and filter backwash and rinse waters, which will be collected reused to hydrate sorbent materials (ash or lime) for SO_2 emissions control. A slipstream of approximately 21 gpm of excess reverse osmosis reject water will be diverted prior to the reuse water tank and discharged to the river. An NDPDES permit will be required to discharge the excess condensate into surface waters.

Storm Water Discharge – Construction

Per NDAC Article 33-16, a permit application must be submitted for construction activities to request inclusion in the NDPDES General Discharge Permit for Storm Water Associated with Construction Activity, Permit NDR10-0000. Prior to start of construction, a Notice of Intent (NOI) must be submitted to the NDDHWQ. Construction can be started within 7-days of submittal of a complete NOI.

Best management practices (BMPs) must be utilized to minimize the effects of erosion caused by construction activities. The BMPs must be installed prior to any land disturbance and maintained through the life of the construction project. Preparation and implementation of a storm water pollution prevention plan (SWPPP) will be required prior to the start of construction. The SWPPP must include descriptions of the site, operational controls and BMPs, erosion and sediment controls, maintenance measures, and inspections. Within 30-days after final stabilization is complete, a Notice of Termination (NOT) must be submitted to the NDDHWQ.

Surface Water Discharge – Operational Site

In the future, a permit application must be submitted to request inclusion in the NDPDES General Discharge Permit for Storm Water Associated with Industrial Activity, Permit NDR05-0000. The application for the Industrial Activity permit must be submitted at least 180 days prior to plant operation. Permitted facilities must comply with storm water discharge monitoring and reporting requirements.

A SWPPP must be submitted with the application for the Industrial Activity permit. Information which must be included in the SWPPP includes final plant layout, final plans and specifications for water or waste holding facilities, identification of potential pollutant sources, storm water management controls, compliance with TMDL allocations (if applicable), previous storm water runoff or ground water sampling results (if available), and information on any spills that have occurred within the last 3 years, if available.

Current site development plans include on-site grading with designated storm water pond areas within the confines of the CHP plant property boundaries. Although no storm water discharges into surface waters are anticipated, it is expected that inclusion in the General Permit will be required to ensure maintenance of storm water management controls. However, compliance with storm water discharge monitoring requirements will not be required.

Groundwater Discharge

Pursuant to the groundwater protection provisions in NDAC Chapter 33-20-13, a permit is required for on-site solid waste impoundments, including installation of ground water monitoring wells and ongoing monitoring of water levels and water quality in the vicinity of the impoundments. Collected ash from the CFB boiler and the air quality control system (AQCS) will be stored in an above ground silo. Since no impoundments are planned, the project will not be subject to the groundwater protection requirements.

Potable and Plant Water Supplies

To obtain rights to use water of the state, including groundwater, a conditional water permit application must be submitted to the North Dakota State Engineer per NDAC Article 89-03. Upon public notification and approval of beneficial use and water appropriation, water rights can be acquired. The construction of surface water storage reservoirs and intake structures also requires approval of the North Dakota State Engineer.

The malt plant maintains water rights for groundwater to supply plant water and potable water uses. Groundwater used primarily for barley wash water in the malt plant is discharged to a lagoon treatment system prior to discharge to the river under an NDPDES permit.

Plant water for the CHP plant will be provided from the malt plant lagoon #4, which is the final impoundment in the lagoon treatment system from which wastewater is currently discharged from the site. A portion of the lagoon discharge will be directed to the CHP plant for treatment and use. Potable water will be provided to the CHP plant from the malt plant's groundwater cistern (freshwater reservoir). Since plant and potable water for this project will be supplied from the malt plant, no water permit applications, groundwater wells or surface water intake projects will be required.

Risk Management Plan / Process Safety Management

Applicability to the USEPA Risk Management Plan (RMP - 40 CFR Part 68) and the Occupational Safety and Health Administration (OSHA) Process Safety Management (PSM) regulation (29 CFR Part 1910.120) will be triggered if the project maintains more than a threshold quantity of a regulated substance on-site. Compliance with either regulation will be required by the date on which a regulated substance is first present on-site above the threshold quantity.

Propane is subject to the USEPA's RMP and OSHA's PSM regulation when the on-site threshold quantity of 10,000 lbs is triggered based on definition as a flammable substance. The CHP plant will use propane as a backup fuel source to natural gas supplied to the auxiliary boilers and CFB boiler start-up burner. Approximately 180,000 gallons of propane are currently stored within six existing horizontal pressure vessels, located adjacent to the CHP plant site. Since the threshold quantity will be exceeded, propane will be subject to the RMP and PSM requirements.

Ammonia is subject to the USEPA's RMP and OSHA's PSM regulation applicability based on the quantity and concentration of ammonia maintained on-site. Table 2-5-6 defines the threshold quantities for ammonia as defined by each regulation. It should be noted that a concentration of less than 44% ammonia will not trigger applicability to PSM, but may trigger RMP requirements. A concentration of less than 20% ammonia will not trigger either regulation.

Table 2-5-5
Ammonia Threshold Quantities

Ammonia Type	CAS Number	Threshold Quantity (lbs)	Basis for Listing
Anhydrous	7664-41-7	10,000 (RMP and PSM)	Mandated for listing by Congress EHS list, vapor pressure 10 mmHg or greater
≥20%wt Ammonia Concentration (aqueous)	7664-41-7	20,000 (RMP)	Mandated for listing by Congress EHS list, vapor pressure 10 mmHg or greater
≥44%wt Ammonia Concentration (aqueous)	7664-41-7	15,000 (PSM)	Mandated by OSHA

If ammonia was stored or within a process (process as defined in either regulation) in quantities above the threshold values listed in Table 5 for each regulation, then applicability to that regulation would be required. However, the CHP plant will use 19% aqueous ammonia in the SNCR, and therefore ammonia will not be subject to either RMP or PSM requirements.

Noise

Noise impacts and mitigation will require definition during a subsequent project phase. Noise impacts and mitigation strategies will be defined in a three-step process: 1) define baseline ambient noise levels, 2) assess noise levels from the new facility and 3) define mitigation strategies to achieve county noise ordinance compliance. Further definition of these steps is as follows:

- A baseline noise survey will be conducted to measure existing ambient noise levels in residential areas near the power plant and at the site property boundary. The measurements will be conducted in twenty-minute continuous noise monitoring intervals to define daytime and nighttime ambient levels.

- Based on selected equipment and a finalized site plan, modeling will be completed to predict noise levels at the proximal residential areas and at the property boundary. These noise impacts will be compared against USEPA and OSHA noise criteria, county regulations and the existing baseline noise levels.

- Depending on results, noise mitigation measures may be required, which could include changing the arrangement/location of equipment, construction of noise-barrier swales and/or installation of acoustic insulation or silencers on equipment.

It is anticipated that noise regulations will require no greater than an integrated day-night average level (L_{dn}) of 55 dBA at the property boundary.

Solid Waste Disposal

CFB boiler bed ash/spent sorbent, AQCS fly ash, and sludge produced from water treatment will be disposed of according to the nonhazardous waste disposal guidelines of Sections 1008 and 4004 of the Resource Conservation and Recovery Act (RCRA), and applicable state solid waste management rules under NDAC Article 33-20. No on-site waste impoundments are planned for the CHP plant. Collected ash will be stored in an aboveground silo prior to truck transfer to a coal mine for use as backfill. It is anticipated that the coal mine will have obtained approval from the North Dakota Department of Health Solid Waste Management Division to accept the ash and the CHP plant will not be subject to waste disposal permitting requirements.

APPENDIX F

FINANCING OPTIONS

In addition to supporting the construction of the Spirit Energy Power Plant, the funding of this project by the North Dakota Industrial Commission and the Lignite Research Council would be sending a message that the energy industry does not need to be confined to the western half of North Dakota. The energy industry is highly underrepresented in the eastern half of North Dakota, with the Energy & Environmental Research Center in Grand Forks being one of few institutions in eastern North Dakota receiving funds from the Lignite Research Council. This project would provide the LRC its first opportunity to provide support for substantial economic impact in eastern North Dakota and signal to the state that the North Dakota Industrial Commission is excited about the development of energy and agriculture in eastern North Dakota while expanding the use of lignite.

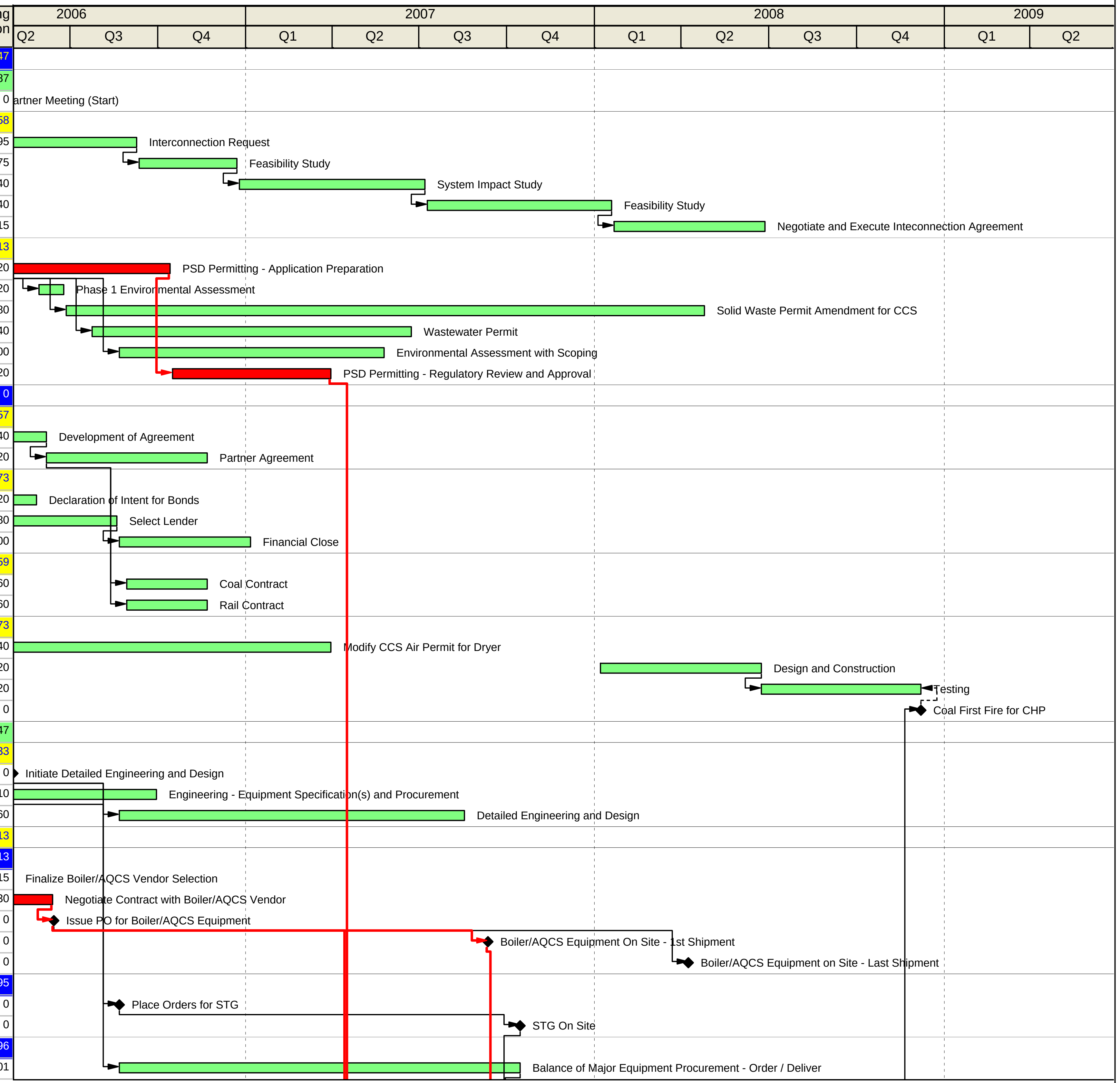
The equity investors of the Spiritwood Energy Park have expended funds to determine the viability of this project, which will provide the largest economic impact to North Dakota since the construction of the railroads, with an estimated impact of $380,000,000. At this point, the greatest challenge to the viability of this project is obtaining financial backing to meet a term and debt equity ratio of 70/30. The support of the North Dakota Industrial Commission through its bonding capabilities, is integral to convincing investors to commit funds. Great River Energy is requesting the same support offered other Lignite Vision 21 projects in the sum of $10,000,000 to promote investor confidence and secure funding.

For potential Spirit Energy investors, the level of grant funding secured by Great River Energy would be important in their decision to commit funds. That is why, at the $10,000,000 funding level, Great River Energy will be willing to negotiate payback terms. For lower funding amounts, these terms may be unappealing to potential investors.

APPENDIX G

NORTH DAKOTA ENERGY PARK

Activity ID	Activity Name	Start	Finish	Remaining Duration
CHP		11-Apr-06	02-Mar-09	747
GRE CHP Administrative Schedule		11-Apr-06	08-Dec-08	687
1	Partner Meeting (Start)	11-Apr-06*		0
MISO Interconnection		01-May-06	27-Jun-08	558
3	Interconnection Request	01-May-06	08-Sep-06	95
4	Feasibility Study	11-Sep-06	22-Dec-06	75
5	System Impact Study	25-Dec-06	06-Jul-07	140
6	Feasibility Study	09-Jul-07	18-Jan-08	140
7	Negotiate and Execute Inteconnection Agreement	21-Jan-08	27-Jun-08	115
Permitting and Enviromental		01-May-06	25-Apr-08	513
10	PSD Permitting - Application Preparation	01-May-06	13-Oct-06	120
12	Phase 1 Environmental Assessment	29-May-06	23-Jun-06	20
13	Solid Waste Permit Amendment for CCS	26-Jun-06	25-Apr-08	480
14	Wastewater Permit	24-Jul-06	22-Jun-07	240
15	Environmental Assessment with Scoping	21-Aug-06	25-May-07	200
11	PSD Permitting - Regulatory Review and Approval	16-Oct-06	30-Mar-07	120
PSD Permitting				0
Partnership Formation		11-Apr-06	20-Nov-06	157
17	Development of Agreement	11-Apr-06	05-Jun-06	40
18	Partner Agreement	06-Jun-06	20-Nov-06	120
Financing		01-May-06	05-Jan-07	173
20	Declaration of Intent for Bonds	01-May-06	26-May-06	20
21	Select Lender	01-May-06	18-Aug-06	80
22	Financial Close	21-Aug-06	05-Jan-07	100
Contracts		29-Aug-06	20-Nov-06	59
23	Coal Contract	29-Aug-06	20-Nov-06	60
24	Rail Contract	29-Aug-06	20-Nov-06	60
Coal Drying/Loading Operation Const/Testing		01-May-06	08-Dec-08	673
26	Modify CCS Air Permit for Dryer	01-May-06	30-Mar-07	240
27	Design and Construction	07-Jan-08	23-Jun-08	120
28	Testing	23-Jun-08	08-Dec-08	120
29	Coal First Fire for CHP	08-Dec-08*		0
Engineering/Procurement/Construction		11-Apr-06	02-Mar-09	747
Engineering		01-May-06	17-Aug-07	333
10005	Initiate Detailed Engineering and Design	01-May-06		0
10015	Engineering - Equipment Specification(s) and Procurement	01-May-06	29-Sep-06	110
10025	Detailed Engineering and Design	21-Aug-06	17-Aug-07	260
Procurement		11-Apr-06	08-Apr-08	513
Boiler/AQCS		11-Apr-06	08-Apr-08	513
10032	Finalize Boiler/AQCS Vendor Selection	11-Apr-06	01-May-06	15
10002	Negotiate Contract with Boiler/AQCS Vendor	02-May-06	12-Jun-06	30
10010	Issue PO for Boiler/AQCS Equipment	13-Jun-06		0
10020	Boiler/AQCS Equipment On Site - 1st Shipment	11-Sep-07		0
10024	Boiler/AQCS Equipment on Site - Last Shipment	08-Apr-08		0
Steam Turbine Generator		21-Aug-06	15-Oct-07	295
10012	Place Orders for STG	21-Aug-06		0
10022	STG On Site	15-Oct-07		0
Balance of Equipment		21-Aug-06	16-Oct-07	296
10016	Balance of Major Equipment Procurement - Order / Deliver	21-Aug-06	15-Oct-07	301



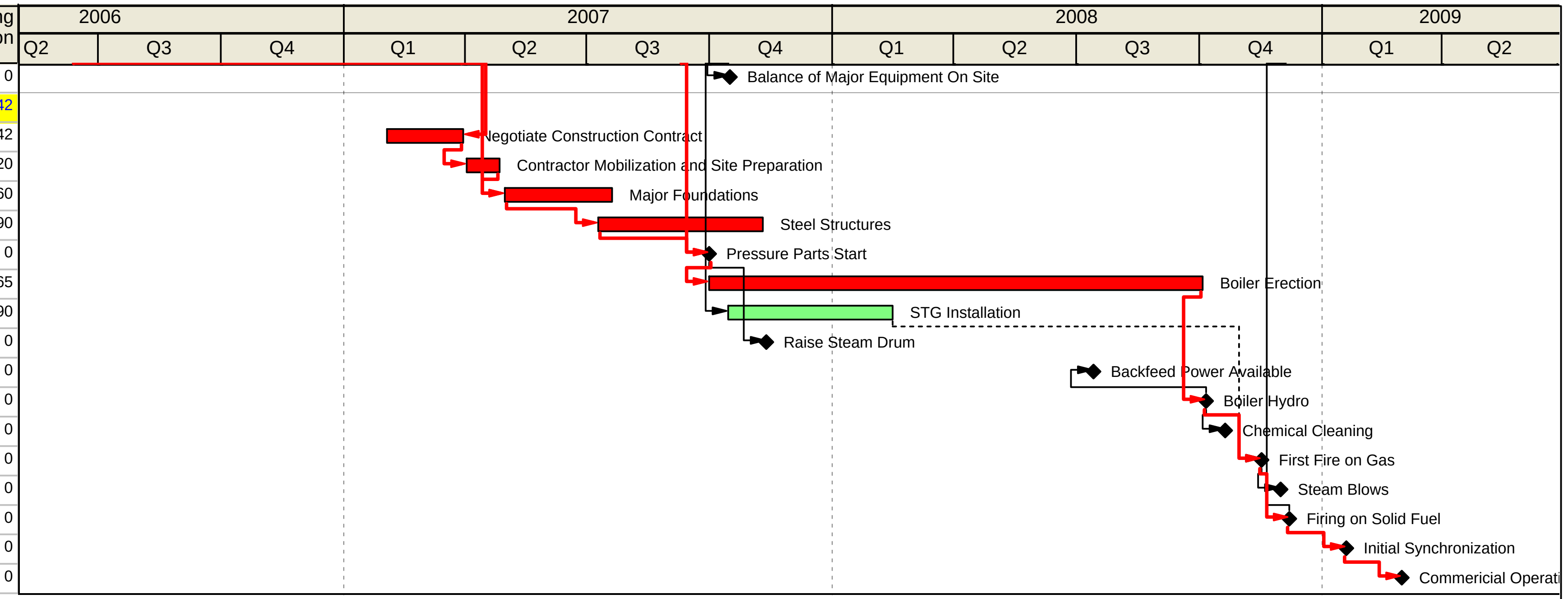
Actual Work — Critical Remaining Work

Remaining Work ◆ — ◆ Milestone

CHP- ND ENERGY PARK

TASK filter: All Activities

Activity ID	Activity Name	Start	Finish	Remaining Duration
10026	Balance of Major Equipment On Site	16-Oct-07		0
Construction		01-Feb-07	02-Mar-09	542
20000	Negotiate Construction Contract	01-Feb-07	30-Mar-07	42
20001	Contractor Mobilization and Site Preparation	02-Apr-07	27-Apr-07	20
20005	Major Foundations	30-Apr-07	20-Jul-07	60
20010	Steel Structures	09-Jul-07	09-Nov-07	90
20012	Pressure Parts Start	01-Oct-07		0
20014	Boiler Erection	01-Oct-07	03-Oct-08	265
20015	STG Installation	15-Oct-07	15-Feb-08	90
20016	Raise Steam Drum	12-Nov-07		0
20017	Backfeed Power Available	14-Jul-08		0
20018	Boiler Hydro	06-Oct-08		0
20020	Chemical Cleaning	20-Oct-08		0
20022	First Fire on Gas	17-Nov-08		0
20024	Steam Blows	01-Dec-08		0
20026	Firing on Solid Fuel	08-Dec-08		0
20030	Initial Synchronization	19-Jan-09		0
20035	Commericial Operation	02-Mar-09		0



Actual Work
Critical Remaining Work
Remaining Work
Milestone

CHP- ND ENERGY PARK

TASK filter: All Activities