



**BASIN ELECTRIC
POWER COOPERATIVE**

Your Touchstone Energy® Cooperative 

Deer Creek Station Alternative Evaluation Analysis and Site Selection Study

(February 2008, Rev 1)

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1. Introduction

Basin Electric Power Cooperative (Basin Electric) is a consumer-owned, regional cooperative headquartered in Bismarck, ND. It generates and transmits electricity to 125 member rural electric systems in nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. These member systems distribute electricity to about 2.5 million consumers.

Basin Electric has established the need for intermediate generating capacity to service the increased use of electricity and the resulting load growth including high load factor industrial and energy-sector (coal, oil, gas, ethanol, and biodiesel) development, and new rural and residential development. A combined cycle combustion turbine (CCCT) facility was one component of an optimal resource expansion portfolio determined to be the least-cost portfolio to provide for future requirements. Basin Electric proposes to construct a new CCCT intermediate resource located in eastern South Dakota to serve member loads.

The purpose of this report is to describe the proposal, and the technological and siting alternatives that were evaluated in its development. The report is prepared in accordance with Rural Utilities Service requirements at 7 CFR 1794.51(c). The material presented here forms in large part the basis for a more detailed assessment to comply with the National Environmental Policy Act.

2. Project Overview

The proposed 250 - 300 MW facility would be named Deer Creek Station and would include a new gas-fired combustion turbine generator set, a heat recovery steam generator (HRSG), and a steam turbine generator set. The site and facility would be designed to accommodate a possible future second unit. Firm gas supply and transportation are available and would satisfy Mid-Continent Area Power Pool (MAPP) accreditation requirements. If a second plant were ever added to the site, ample gas supply will be available. Power from the facility would be supplied to Basin Electric's customers through an interconnection with Western Area Power Administration's (Western) transmission system. Western is a federal power marketing agency with the U.S. Department of Energy (DOE).

3. Project Need and Justification

Existing Resources

Basin Electric's generating resources include two coal-based power plants in North Dakota – the Antelope Valley Station, Beulah, and the Leland Olds Station, Stanton; a coal-based power plant in Wyoming – the Laramie River Station, Wheatland; an oil-based peaking station – the Spirit Mound Station, Vermillion, S.D.; nine combustion-turbine generators (natural gas) in the Gillette, Wyo., area; two gas-fired peaking stations – the Groton Generation Station near Groton, S.D., and the Wisdom Station Unit 2 near Spencer, Iowa; four wind turbines – two near Minot, N.D., and two near Chamberlain, S.D. Basin Electric purchases the entire output of three wind farms owned and operated by FPL Energy – one near Edgeley/Kulm and one near Wilton in North Dakota, and another near Highmore in South Dakota; and two other 750-kilowatt wind

turbines, one located near Pipestone, Minn., and another near Rosebud, S.D. Basin Electric also purchases the entire production of four recovered energy projects located along the Northern Border Pipeline. Basin Electric also manages and maintains 2,424 miles of high-voltage transmission lines; 40 switchyards and substations, and 58 microwave installations used for communications and system protection.

Projected Energy Requirements

Between 1999 and 2006, Basin Electric system peak demand increased 752 MW from 1,195 to 1,947 MW or approximately 107 MW per year. Basin Electric system energy sales increased 5.3 million MWh (from 6.5 million MWh to 11.8 million MWh) or approximately 760,000 MWh per year. Basin Electric forecasts peak demand on its system to grow by 1,834 MW from 2006 through 2021 or approximately 122 MW per year. Basin Electric forecasts energy consumption on its system to grow by approximately 12 million MWh from 2006 through 2021 or approximately 800,000 MWh per year. The average expected increase in energy sales compared to the average expected increase in peak demand results in a 75% annual load factor for the forecasted load growth. Demand is forecasted to double in the next 15 years, with 1,947 MW in 2006 projected to grow 1,834 MW by 2021, and 2006 energy usage at 11.8 million MWh forecasted to grow 12 million MWh by 2021. The load growth is driven mainly by commercial sector growth which includes energy related development in the form of coal, oil and gas development and also increased loads in the residential sector mainly located on the outskirts of larger cities within the service territory.

The difference in the load forecast plus other obligations (such as sales, losses, and reserves less Basin’s system-wide load management), and existing and planned generating resources along with purchases define the load and capability of the Basin Electric system which shows the amount of surplus capacity on the system. Figure 1 shows Basin Electric’s total system summer surplus capacity.

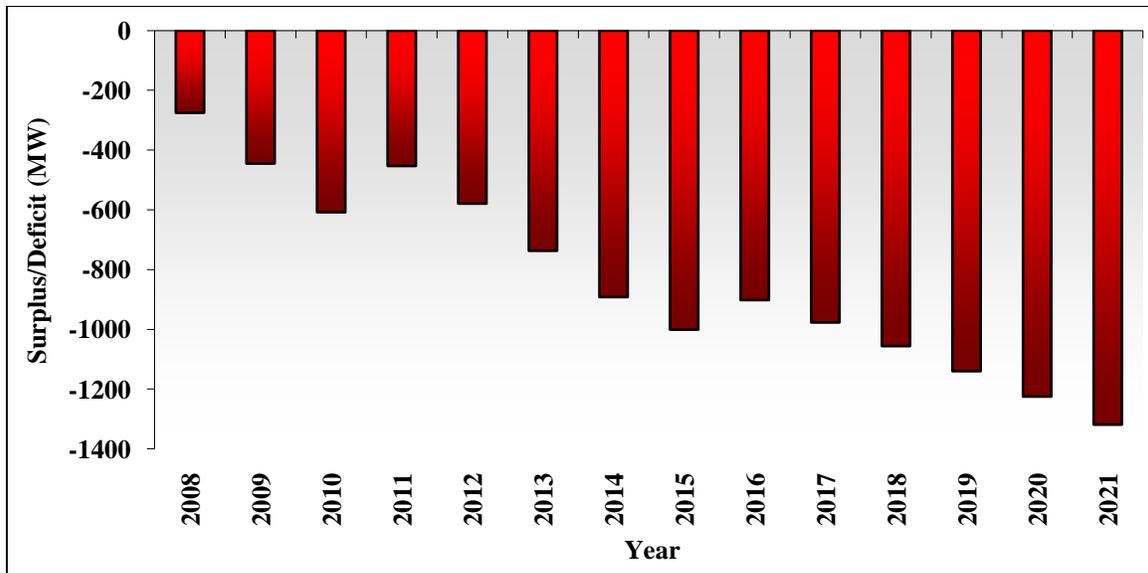


Figure 1. Total System Load and Capability

Basin Electric's total system deficit is 275 MW in 2008 and is forecasted to increase steadily over time. The two periods that do not produce additional deficits from one year to the next are when the Dry Fork Station in Wyoming is anticipated to go commercial in 2011 and when a long-term power supply obligation ends in early 2016. With the addition of the Dry Fork Station and ending of the long-term power supply obligation, no additional generation is required on Basin Electric's Western System and therefore the additional resource required will be on Basin Electric's Eastern System.

4. Alternative Evaluation Analysis

Basin Electric's 2007 Power Supply Analysis (PSA) provides an in depth look at its current operating system, future load growth and the framework for future expansion, including both supply-side and demand-side resource expansion. Twelve resource expansion portfolios were created to meet the forecasted needs of Basin Electric and were evaluated with respect to cost, performance, and risk. All portfolios included some component of wind energy development. The twelve portfolios ranged from emphasizing nearly all baseload development to all peaking development, with various combinations in between.

A number of demand-side and supply-side resource alternatives have been considered as a means of meeting the forecasted electrical need for Basin Electric. The alternatives evaluated include:

- Demand Side Management
- Renewable Energy Sources
 - Wind
 - Solar
 - Hydroelectric
 - Geothermal
 - Biomass Power
 - Biogas
 - Municipal Solid Waste
- Fossil Fuel Generation
 - Simple Cycle Combustion Turbines
 - Combined Cycle Combustion Turbines
 - Microturbines
 - Coal Facility
- Nuclear Power
- Repowering/Uprating of Existing Generating Units
- Participation in Another Utility's Generation Project
- Purchased Power / Request for Proposals
- New Transmission Capacity

The most economical means of supplying power to a load that varies every hour on an electric power system is to have three basic types of generating assets available for use. These generation assets are commonly referred to as baseload, intermediate, and peaking capacity.

Baseload capacity runs at its full capacity continuously throughout the day and night, throughout the year. The output of baseload-type plants cannot be rapidly decreased or increased to “follow load.” Baseload units are designed to optimize the balance between high capital/installation cost and low fuel cost, resulting in the lowest overall production cost under the assumption that the unit will be heavily loaded for most of its life. Typically, baseload capacity units are operated around 80 percent capacity factor or more. Coal-fired power plants, nuclear plants, and hydroelectric plants are examples of baseload generation capacity; however, hydro plants that follow load are not considered baseload units.

Intermediate capacity units are designed to be “cycled” at low load periods, such as evening and weekends. The units are loaded up and down rapidly to handle the load swings of the system while the unit is online. Typically, intermediate capacity units are operated between a 20 and 80 percent capacity factor, or between baseload and peaking.

Peaking capacity is only operated during peak load periods and during emergencies. Very low capital/installation costs are important due to the fact these units are typically not operated very much. The production costs are relatively high due to the high cost and volatility in the price of fuel. Types of peaking capacity power plants include combustion turbines, internal combustion engine plants, and pumped-storage hydroelectric facilities. Typically, peaking resources are operated under a 20 percent capacity factor.

The generation types capable of meeting an intermediate need of Basin Electric’s would be the alternatives that have a capacity factor between 20 percent and 80 percent, which include wind, solar, hydroelectric and combined cycle combustion turbines. Wind is an intermittent resource that cannot be scheduled when to operate but does not cost a whole lot due to the fact it is a fuel displacer. Wind would integrate very well with gas fired generation to produce a more useable product. Solar is also an intermittent resource that cannot be scheduled when to operate however it is very costly. Hydroelectric power generally operates between 40 and 50 percent capacity factor, however it is very dependent on annual rainfall and therefore can go through some long periods of low generation, and the upper Midwest has seen several years of drought so water is currently limited. Combined cycle combustions turbines are an excellent source to meet Basin Electric’s intermediate generating resource need; combined cycles do not tend to have a stable fuel cost however the fuel is generally there when needed. For these reasons a CCCT facility was determined to be the most cost effective option to meet Basin Electric’s intermediate generating resource needs.

Of the twelve resource expansion portfolios analyzed in the PSA, the preferred portfolio included 300 MW of wind, 200 MW of peaking generation, 250 MW of intermediate generation and 600 MW of baseload coal generation. The Deer Creek Station is proposed to meet Basin Electric’s projected intermediate generation requirement. While baseload and peaking capacity units are being contemplated for inclusion in Basin Electric’s resource expansion plan, they are not addressed in this alternative evaluation analysis.

Demand Side Management

Demand Side Management (DSM) is the process of managing the consumption of energy, generally to optimize available and planned generation resources. According to the Department

of Energy, DSM refers to “actions taken on the customer’s side of the meter to change the amount or timing of energy consumption. Utility DSM programs offer a variety of measures that can reduce energy consumption and consumer energy expenses. Electricity DSM strategies have the goal of maximizing end-use efficiency to avoid or postpone the construction of new generating plants.”

DSM programs aim to achieve three broad objectives: energy conservation, energy efficiency and load management. Energy conservation can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking energy and other uses. Energy efficiency can encourage consumers to use energy more efficiently, and thus get more out of each unit of electricity produced. Load management allows generation companies to better manage the timing of their consumers’ energy use, and thus help reduce the large discrepancy between on-peak and off-peak demand.

Approximately half of the Basin Electric members are utilizing load management to manage their power purchases from Basin Electric. Basin Electric has implemented a system-wide load management program on its eastern system which enables Basin Electric to target large loads and/or generation that are not included in the members’ load management programs to be used during Basin Electric’s seasonal peak periods. Basin Electric has approximately 6-10 MW of load management available at this time.

DSM programs are capable of reducing the energy demand and reducing the required capacity of future additional generation facilities. It is apparent, however, that energy savings through DSM are not enough to alleviate the need for the intermediate resource fulfilled by the current proposal.

Repowering/Uprating of Existing Generating Units

Basin Electric has committed to upgrading the high pressure and intermediate pressure (HP/IP) turbine section of the main turbine at all three units of the Laramie River Station. The Unit 2 upgrade occurred in the spring 2007 maintenance outage, unit 3 is scheduled to occur in the spring 2008 maintenance outage and unit 1 in the spring 2009 maintenance outage. The upgrade to the HP/IP turbine is anticipated to increase the net output of each unit by 8-12 MW for a total of 24-36 MW. Basin Electric could see an additional 10-15 MW from the upgrades of these turbines, due to its 42.27% ownership share of the Missouri Basin Power Project (MBPP). These increases in net output are due to efficiency increases, without increasing the fuel input to the units.

Basin Electric has also committed to retrofitting the low pressure (LP) turbine sections of Unit 2 in the Leland Olds Station. This upgrade when completed in 2009, should increase the net output by 5.5 MW. This increase in net output is due to efficiency increases, without increasing the fuel input to the unit.

Basin Electric has also evaluated the option of upgrading the HP/IP turbines at the Antelope Valley Station; however work within the boiler would need to be done to make this a viable project. This work would require full “New Source Review” (NSR) for modification of the

boiler. Basin Electric has decided not to move forward with the upgraded turbines at the Antelope Valley Station.

While Basin Electric has made progress in upgrading existing facilities, it is apparent that the scale of the improvements does not alleviate the need for the intermediate resource fulfilled by the current proposal.

Participation in Another Utility's Generation Project

Basin Electric has been having discussions with some neighboring utilities about participating in a third unit at the Milton R. Young Station near Center, North Dakota. Basin Electric is looking at a 100 MW share of a 500 MW unit to be operational in the 2016-2020 time period.

This participation could help meet a portion of Basin Electric's long-term need for increased generating capacity in the region, but would not meet the need for its short-term intermediate resource requirements.

Purchased Power / Request for Proposals

Basin Electric has signed a 25-year contract with the developer of four current Recovered Energy Generation (REG) power plants, which are fueled by hot exhaust heat off the Northern Border Pipeline, to purchase the output from four additional REG power plants. There will be one site each in Montana and Minnesota, and two sites in North Dakota. These additional four sites should have a total combined output of 22 MW and are anticipated to be operational in 2009. The generation is environmentally benign, using virtually no additional fuel and producing virtually zero emissions.

Basin Electric hired Power Systems Engineering (PSE) to develop and issue a Request for Proposals (RFP) in early 2007 for short- and long-term power supply on both its eastern and western system. The long-term proposals were used to evaluate against Basin Electric's self-build options. The short-term proposals could be utilized to meet some of Basin Electric's need in the next couple of years. Renewable proposals were also sought.

Short-term Proposals

Basin Electric received short-term proposals from nine different entities for power products located in both of Basin Electric's eastern and western systems. The short-term proposals were evaluated by PSE.

Figure 2 compares Basin Electric's eastern system needed generation capacity to the magnitude of proposals received. From this information it was determined that Basin Electric could purchase the needed power from the market through 2009 but would need to develop additional resources to meet the needed obligations beyond 2009. Basin Electric did elect to short-list one proposal from the proposals received for delivery into Basin Electric's eastern system. It was believed that the short-term proposals were more costly than Basin Electric's self build options.

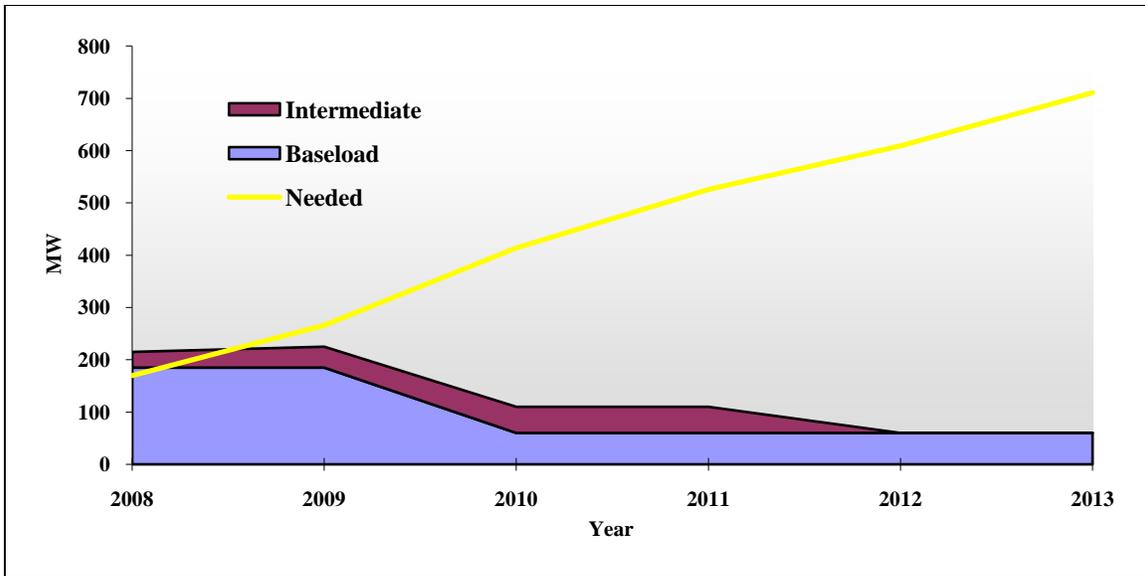


Figure 2. East System Short-Term RFP Proposals

Long-term Proposals

Basin Electric received four conventional long-term power purchase proposals from two different entities for either coal generation or a combination combined cycle and simple cycle generation. It was believed that the four long-term proposals were more costly than Basin Electric’s self build options. These conventional long-term proposals were evaluated by PSE.

Renewable Proposals

Basin Electric received 12 proposals from nine different entities for wind generation. These 12 wind proposals were located in North Dakota, South Dakota, Montana and Wyoming. Figure 3 shows the anticipated first-year bus bar of each proposal. The renewable proposals were evaluated by Basin Electric staff.

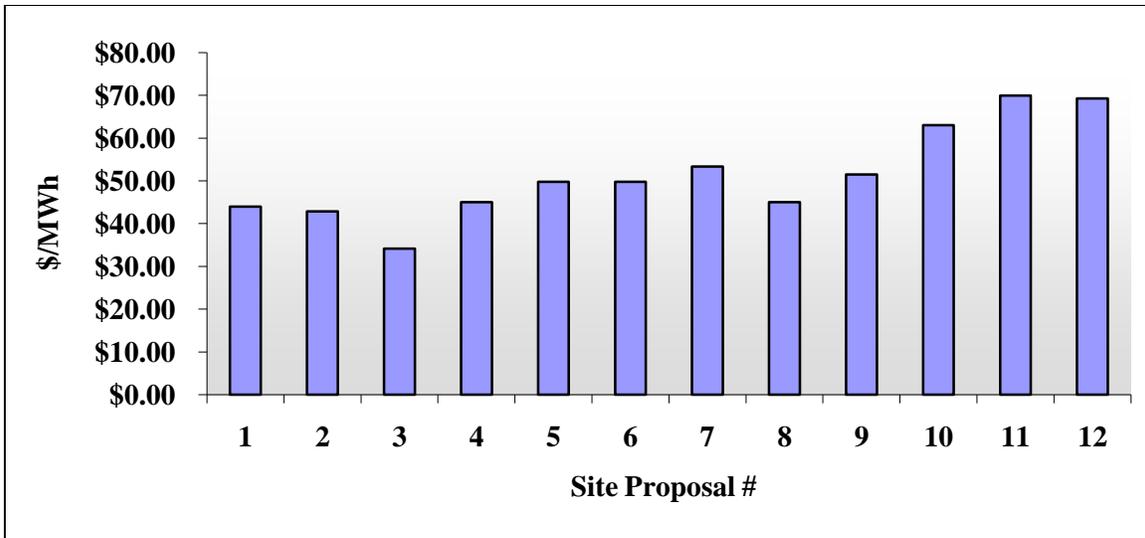


Figure 3. Renewable Proposals First-Year Bus Bar Costs

Based on the anticipated capacity factor, location and bus bar cost, proposal 3 was short-listed to be compared to Basin Electric’s own self-build option for wind generation. Proposal 3 is still being evaluated. Wind generation, however, is not an “on call” resource and therefore is not capable of fulfilling the purpose and need for an intermediate resource on its own.

New Transmission Capacity

Today there is limited available transmission capacity (ATC) on the transmission system to move power into the Integrated System (IS) from Nebraska Public Power District (NPPD), Mid-American Energy Company (MEC), Midwest Independent Transmission System Operator (MISO) or Saskatchewan. In order to bring in enough power to cover Basin Electric’s total need, additional transmission would need to be built and there would probably be upgrades needed to third-party transmission in order to move the power into the region.

The other question becomes is there existing generation outside the region to meet Basin Electric’s need. The Request for Proposals provided few responses for power outside the IS area during the short term; one proposal within MISO, one proposal within MEC and one proposal from within NPPD. One proposal for a long-term output of a new coal plant was received that would result in either additional transmission to be built or additional wheeling expense to move the power into the IS or both. Because of these anticipated higher costs, Basin Electric feels it would be a better economic decision to build the new generation within the IS and therefore avoid some unnecessary transmission costs to provide power to the membership at the lowest reasonable cost.

Combined Cycle Combustion Turbine (CCCT)

Combined cycle is a term used when a power producing engine or plant employs more than one thermodynamic cycle. In a combined cycle power plant (CCPP) or combined cycle combustion turbine (CCCT) plant, a gas turbine generator generates electricity and the waste heat from the gas turbine is used to make steam to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. In a thermal power plant, high-

temperature heat as input to the power plant, usually from burning of fuel, is converted to electricity as one of the outputs and low-temperature heat as another output. As a rule, in order to achieve high efficiency, the temperature of the input heat should be as high as possible and the temperature of the output heat as low as possible. This is achieved by combining the Rankine (steam power system) and the Brayton (gas turbine) thermodynamic cycles. Figure 4 shows a typical combined cycle unit process flow diagram.

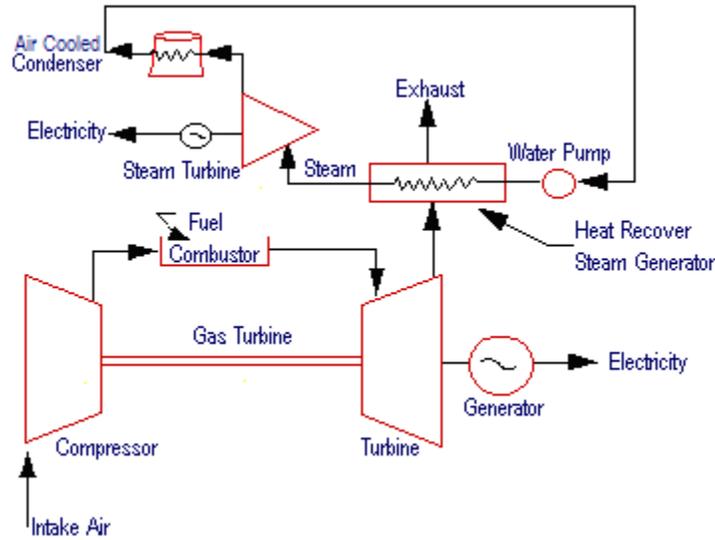


Figure 4. Combined Cycle Unit Process Flow Diagram

The thermal efficiency of a combined cycle power plant is normally in terms of the net power output of the plant as a percentage of the lower heating value of the fuel. Typical combined cycle plants are powered by natural gas, although other sources of fuel can be used such as fuel oil or synthetic gas.

Combined cycle equipment is pre-engineered and factory packaged to minimize installation time and cost. All major equipment (gas turbine generator, heat recovery steam generator, and steam turbine generator) is shipped to the field as assembled and tested components. CCCT plants have demonstrated high reliability and low operations and maintenance costs.

The capital cost component of the levelized cost of CCCT power is approximately \$18/MWh for a plant that runs at about 60 percent annual capacity factor. The total levelized cost of CCCT power is projected to be approximately \$92/MWh for about 5,250 hours of operation in a year or about 60 percent annual capacity factor. If a CCCT plant were operated at 80 percent annual capacity factor, the levelized cost of power would be about \$86/MWh. Most of the power-generation cost for a CCCT plant is from the variable/fuel cost at approximately \$69/MWh, assuming the cost of fuel is about \$6.50/MMBtu. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Traditionally, demand for natural gas peaks in the coldest months, but with the nation's power increasingly being generated by natural gas, demand also spikes in summer, when companies fire-up peaking plants to provide more power for cooling needs.

Summary of Alternatives

For the reasons described above, neither demand side management, repowering, project partnerships, purchased power, nor new transmission capacity meet the need for the intermediate resource fulfilled by the current proposal. CCCT facilities have been a proven solution for meeting intermediate resource requirements industry wide and this type of facility logically meets Basin Electric's intermediate generating resource need.

5. Site Selection Study

Basin Electric has established the need for additional intermediate capacity to serve forecasted member load growth. Basin Electric has concluded that an intermediate resource located in eastern South Dakota is necessary to fulfill its member obligations. Eastern South Dakota was selected because it is outside the existing North Dakota export transmission constraint but within the Integrated Transmission System (IS) and proximity to an adequate fuel supply. The IS is owned by Western Area Power Administration, Basin Electric Power Cooperative and Heartland Consumers Power District. As discussed in the Alternative Evaluation Analysis, a CCCT facility appears to be the best alternative for Basin Electric's use as an intermediate resource. There were several factors considered in evaluating potential plant sites: access to a high voltage transmission system with available capacity, fuel supply, water supply, existing land use and terrain, and proximity to residences.

Initially, five potential plant sites were identified in eastern South Dakota. Following a preliminary review of environmental constraints including obvious exclusion or avoidance areas and existence of required factors such as fuel supply and transmission lines, the number of proposed locations was reduced to two candidate sites.

The five potential plant sites initially chosen are shown on Figure 5. The potential sites are located within Basin Electric membership areas in eastern South Dakota. The Groton Site is located near Aberdeen, SD, the Watertown Site is about halfway between Watertown and Brookings, SD, and the White Sites 1, 2, and 3 are located near Brookings, SD.

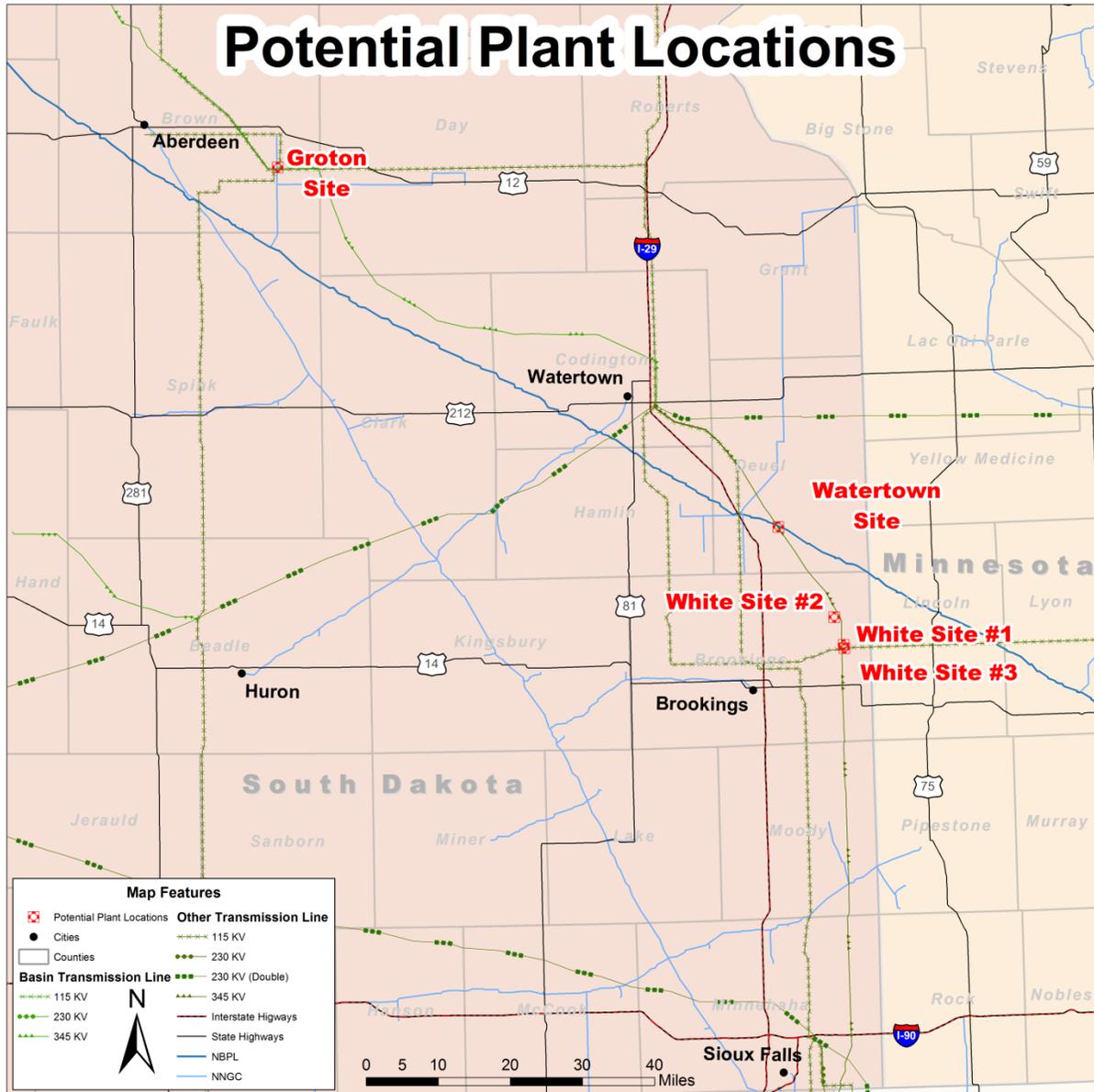


Figure 5. Potential Plant Sites

BEPC staff completed an initial field review of these five sites in August and September, 2007. The purpose of this site screening field review was to verify the accuracy of databases used to locate existing natural gas pipelines, transmission lines and substations, and the spatial relationship of these resources to each other in the area surrounding the potential sites. Existing water supplies and transportation access were also documented. Potential environmental and human constraints in the area surrounding the potential sites were also noted. Regional air quality constraints, land use compatibility, geologic hazards, potential biological or cultural resource constraints, wetlands, and any potential for hazardous waste or spill sites in the general area were considered. Based on this initial field review, three of the five potential sites were rejected from future consideration. This evaluation is depicted in Table 1. The three sites that

were evaluated as the lowest rankings and therefore rejected from further study were the Groton Site, the Watertown Site, and White Site 3.

Table 1. Initial Site Evaluation

| Site | Groton | WaterTown | White Site 1 | White Site 2 | White Site 3 |
|--------------------------------|-----------|------------|--------------|--------------|--------------|
| Site Conditions | Congested | Greenfield | Greenfield | Greenfield | Greenfield |
| Transmission Access | 2 | 3 | 1 | 2 | 2 |
| Transmission Capacity | 2 | 1 | 1 | 1 | 1 |
| Substation Required? | 1 | 3 | 1 | 3 | 1 |
| Fuel Supply/Length | 3 | 1 | 3 | 2 | 3 |
| Water Supply | 3 | 3 | 2 | 2 | 2 |
| Land Use | 1 | 3 | 1 | 1 | 1 |
| Terrain | 2 | 2 | 1 | 1 | 3 |
| Proximity to Residences | 3 | 3 | 1 | 2 | 3 |
| Ranking | 17 | 19 | 11 | 14 | 16 |

Ranking: 1 – Most Favorable, 2- Moderate and 3- Least Favorable

The Groton Site was rejected due to property and transmission constraints due to the previous installation of two simple cycle peaking facilities and also the limitation of the water and fuel supply. The Watertown Site was rejected due to the long distances to the nearest substation and water supply, the increase costs associated with the need for an additional substation and congested land use issues. White Site 3 was rejected because it is not large enough for a CCCT facility and terrain suitability.

The two sites that were suitable for further study following the initial screening were White Sites 1 and 2 (see Figure 6). These two sites were evaluated in more detail according to the screening criteria listed in Table 1 and an incremental cost comparison has been prepared to further evaluate the two sites.

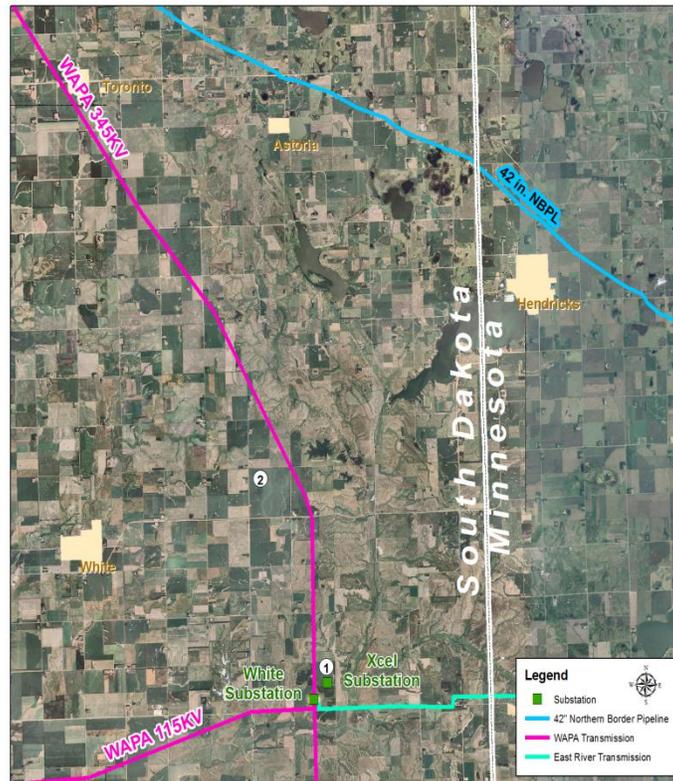
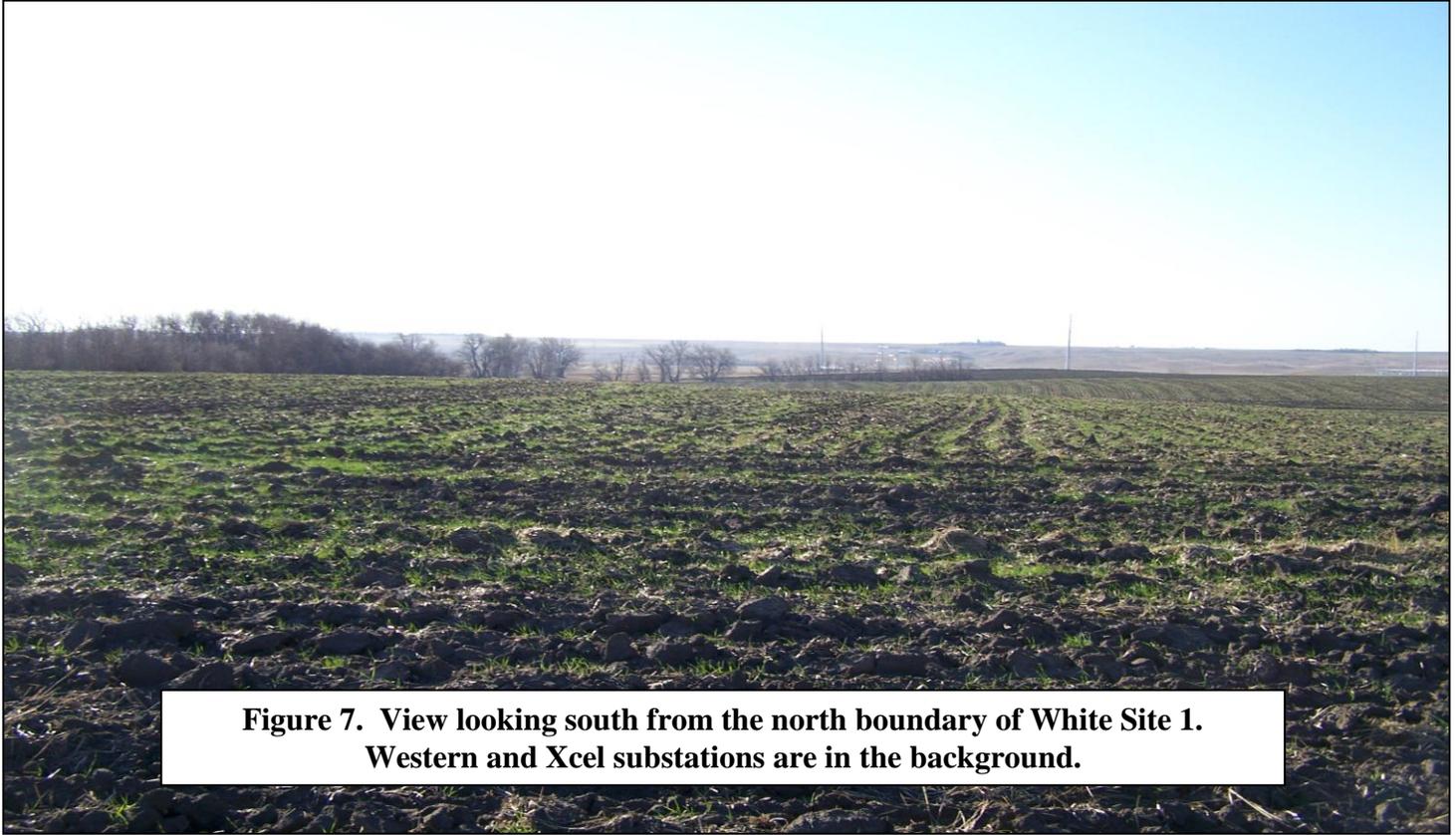


Figure 6. Location of White Sites 1 and 2, Brookings County, South Dakota.

Fuel Supply

The two sites under consideration (see Figures 7 thru 10) are located near the Northern Border Pipeline (NBPL), thus ensuring a reliable fuel source is available. White Site 1 is located approximately 6 miles southeast of White, South Dakota in the northeast quarter of Section 25, Township 111 North, Range 48 West, of the Fifth Principal Meridian, Brookings County. White Site 2 is located approximately 4 miles east-northeast of White, South Dakota in the northwest quarter of Section 2, Township 111 North, Range 48 West, of the Fifth Principal Meridian, Brookings County. Firm gas supply and transportation agreements are available with Northern Border Pipeline that meet Mid-Continent Area Power Pool (MAPP) accreditation requirements. The compressor station locations are also favorable because of existing above-ground pipeline taps. White Site 1 is located further from the NBPL than White Site 2; however the rugged topography of the area near White Site 2 dictates that the pipeline to either site would be nearly the same length. As a result, neither site has an advantage over the other with respect to fuel supply.



**Figure 7. View looking south from the north boundary of White Site 1.
Western and Xcel substations are in the background.**

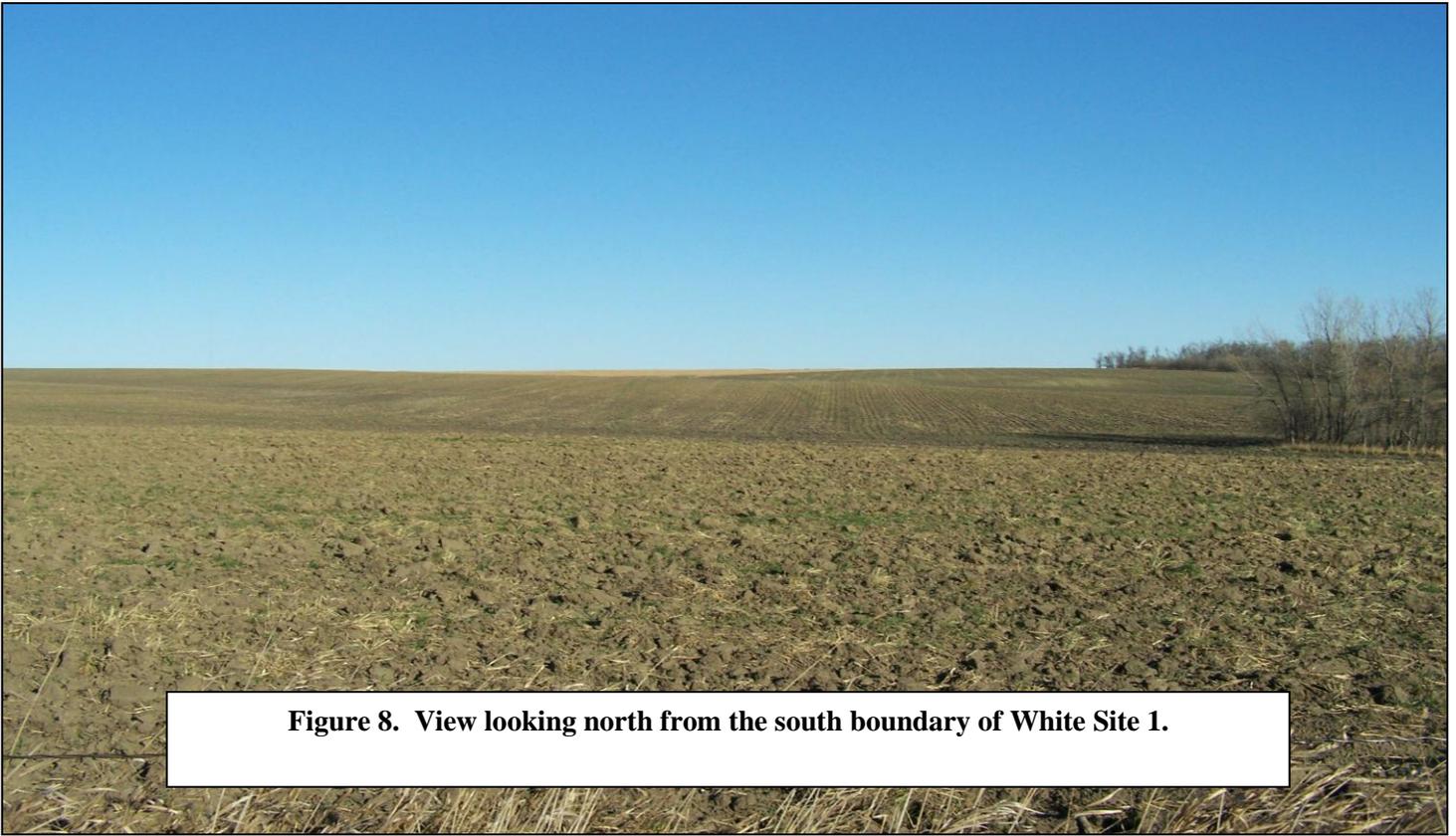


Figure 8. View looking north from the south boundary of White Site 1.

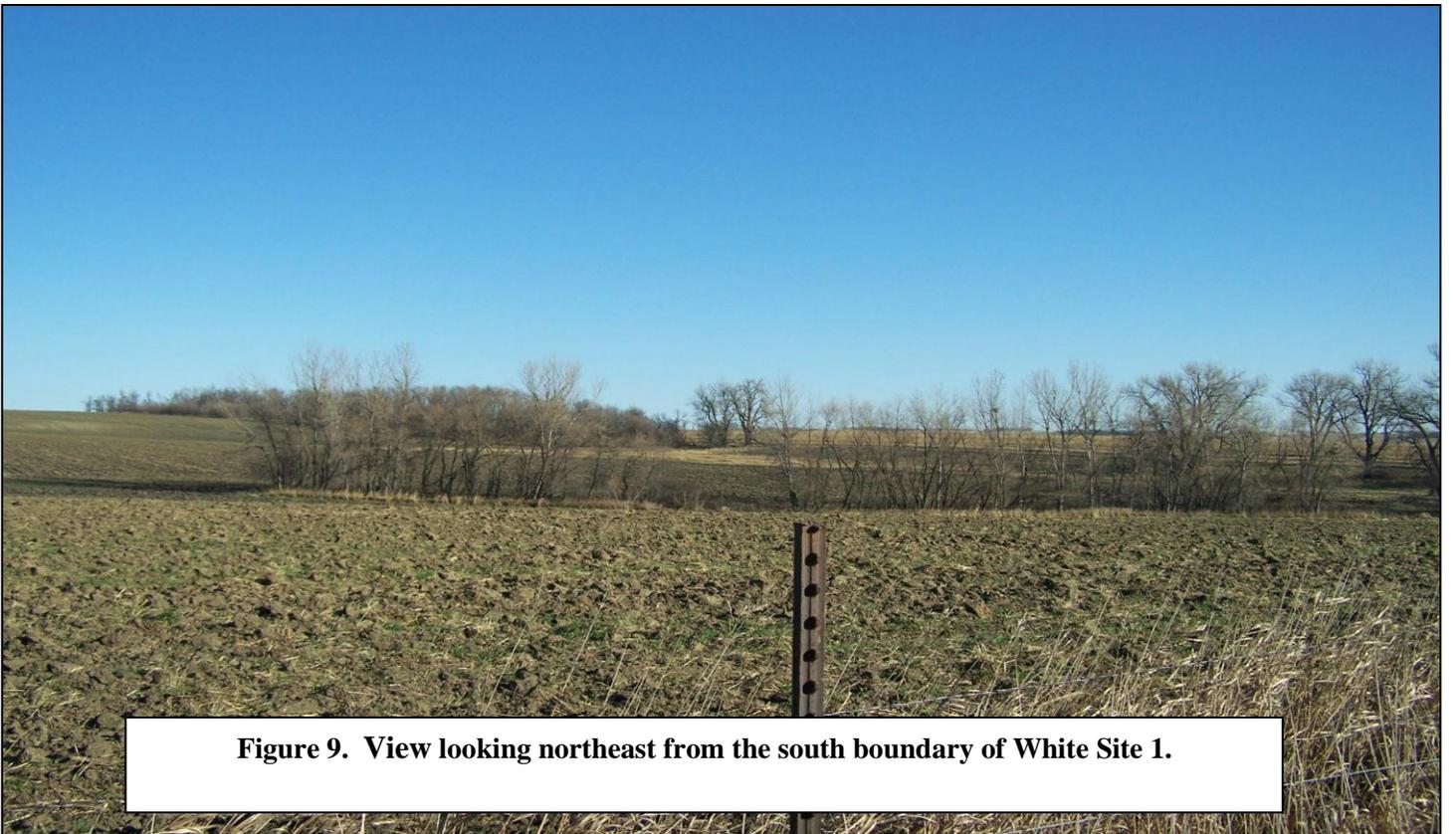


Figure 9. View looking northeast from the south boundary of White Site 1.

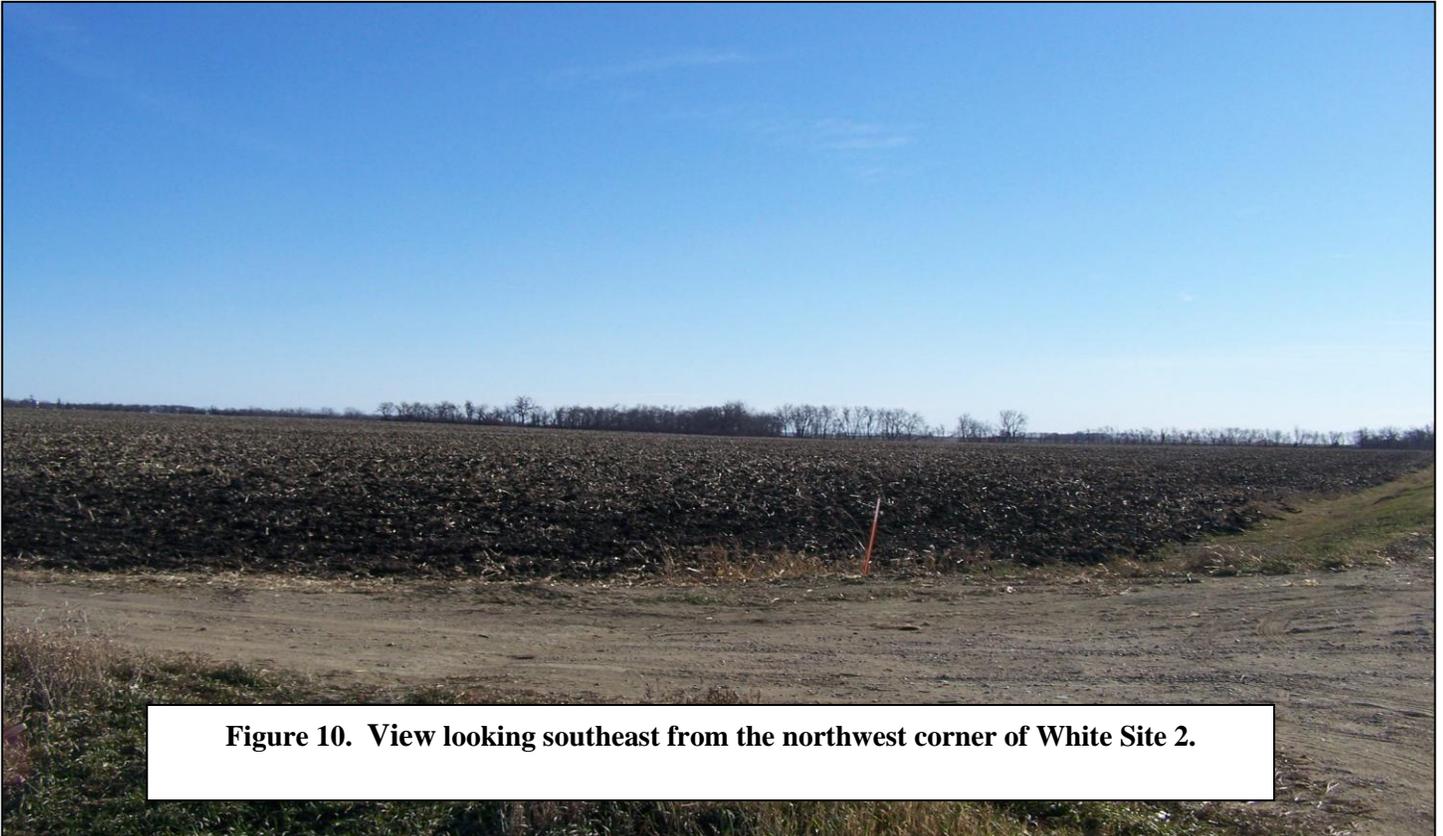


Figure 10. View looking southeast from the northwest corner of White Site 2.

Land Use/Terrain

The terrain in the White Site 1 study area is relatively flat and slopes from the northwest to the southeast; the area surrounding the site is well-drained. The area under consideration for White Site 1 is agricultural, consisting primarily of farmland. The elevation of White Site 1 is approximately 1850 feet above mean sea level (msl). The terrain around the White Site 2 study area is very flat consisting primarily of farmland. The elevation of White Site 2 is approximately 1935 feet above mean sea level (msl). Since both sites are relatively flat, neither site has an advantage over the other with respect to constructability. However, White Site 1 is preferred with respect to terrain because the slope of White Site 1 would allow better drainage than White Site 2. Also, the lower elevation of White Site 1, as compared to White Site 2, would yield slightly better gas turbine performance. This is because gas turbine performance decreases as elevation increases due to a decrease in air density.

Water Supply

Water usage for the proposed CCCT facility would be minimal because an air cooled condenser would be used to condense the steam that exits the steam turbine, rather than a water cooled condenser and cooling tower combination for this purpose. The facility would use water for control of nitrogen oxide (NO_x) emissions, evaporative cooling, and for make-up water needs. A single unit facility would normally consume 25 gallons of treated water per minute with a maximum of 60 gallons of treated water per minute. The facility would use a groundwater

source as no rural water distribution system currently exists at either site and because systems nearby are approaching full capacity. Currently, the exact location of a sufficient groundwater source for the sites remains undetermined; several test wells would be required to locate a source capable of delivering both sufficient water supply and properties to satisfy various station service water requirements. Since both sites would use a groundwater source, neither site has an advantage over the other with respect to water supply.

Transmission Access

Existing transmission in the vicinity of White Site 1 includes a Western 345 kV line just west of the site. An existing 345/115 kV substation owned by Western is located about 1/2 mile southwest of the potential site. There are presently two 115 kV transmission lines (one owned by Western and one owned by East River Electric Power Cooperative) tied into this substation. A 345/115 kV substation owned by Xcel is located about 1/3 mile south of White Site 1. White Site 2 is located approximately 1/3 mile west of the same Western 345 kV line, and 4 3/4 miles north of the same 345/115kV substation owned by Western and the 345/115 kV substation owned by Xcel. Power from a CCCT facility located at White Site 1 would be interconnected into the existing 345 kV bus in Western's White Substation via a new 1/2 mile 345 kV transmission line. At White Site 2 a new substation would be required to be constructed and would interconnect to Western's 345 kV transmission line thru two 3/4 mile 345 kV lines. The shorter transmission line associated with White Site 1 and no requirement to construct a substation would cause less land to be disturbed by construction activities and would also be less costly due to fewer materials and less labor being required. As such, White Site 1 has a significant advantage over White Site 2 since it is much closer to the high voltage transmission system and existing substation.

Proximity to Residences

A facility on White Site 1 would be located approximately 1 mile away from the nearest occupied residence while on White Site 2 it would be located approximately 1/2 mile away from the nearest occupied residence. Therefore, White Site 1 has an advantage over White Site 2 because it is located farther away from the nearest occupied residence.

Site Selection Summary

Based on the evaluation criteria applied in the site selection process (access to a high voltage transmission system with available capacity, fuel supply, water supply, existing land use and terrain, and proximity to nearest occupied residence), White Site 1 appears to offer considerable advantages versus White Site 2. The terrain of White Site 1 allows for better drainage than White Site 2. The lower elevation of White Site 1 means that a gas turbine would perform better at White Site 1 than at White Site 2. The relatively short distances to high voltage transmission facilities at White Site 1 would cause fewer disturbances of natural resources and be less costly because fewer materials and less labor would be required. White Site 1 is also further away from the nearest occupied residence than White Site 2. Table 2 depicts the incremental costs associated with White Site I and White Site 2. For the reasons listed above and the increased costs associated with White Site 2, White Site 1 is considered the Preferred Site.

Table 2. Incremental Cost Comparison

| | White Site 1 | White Site 2 |
|--------------------------------|---------------------|---------------------|
| Site Conditions | Base | Same |
| Transmission Access | Base | \$750,000 |
| Transmission Capacity | Base | Same |
| Substation | Base | \$10,000,000 |
| Fuel Supply/Length | Base | (\$1,000,000) |
| Water Supply | Base | Same |
| Land Use | Base | Same |
| Terrain | Base | (\$500,000) |
| Proximity to Residences | Base | Same |
| Cost | Base | \$10,250,000 |

6. *References*

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