Chapter 6. Thermal Generation

Xcel Energy's thermal generation system is comprised of a combination of nuclear, coal, biomass, hydro, gas and oil fueled generating facilities. These facilities serve as the backbone of our system, supplying in excess of 80% of the energy used by our customers annually. In total, the system is expected to have about 8,800 MW of MISO-accredited capacity resources for the summer of 2011. Coal and biomass resources comprise about 35.4% or 3,300 MW of that total; Company-owned oil and gas-fired generating resources account for about 32.9% or 2894 MW; and nuclear resources account for 18.2% or 1,604 MW.

Maximizing the value of our existing thermal resources through strategic investments will ensure they continue to provide low-cost, reliable service to our customers. In this chapter, we describe our existing thermal generating units, present the key issues associated with these resources and express our plans for the future.

As discussed in our 2007 Resource Plan filing, we have been evaluating the costs and benefits of repowering our Black Dog Units 3 and 4 with natural gas as opposed to extending its life as a coal-fired unit. Based on these evaluations, we propose to repower Black Dog 3 and 4 as a 680 MW natural gas-fired combined cycle facility in 2016. Our proposal to repower Black Dog is one of the key components of our Resource Plan, offering significant improvements in reliability and environmental performance at a reasonable cost to our consumers. We will also be evaluating some of our older facilities, including Sherco 1&2, to determine how they will fit into our system in the future. Finally, we will be developing our options for peaking resources in the event that we need to add other resources during the planning period.

The following sections discuss each of our thermal facilities and then describe changes that we have planned for certain facilities.

Existing Fossil-Fuel Resources

Allen S. King Plant
The Allen S. King Plant is located on the St. Croix River in Oak Park Heights, Minnesota, just east of the Twin Cities. It is a single-unit coal-fired generating plant burning low sulfur Wyoming coal. The unit provides base load electric service, for the most part operating 24 hours a day, seven days a week. Its current power production capability is 510 MW based on summer ratings.

The original King generating unit went into service in 1968 and served reliably for more than 35 years. Starting in 2005, the King plant was completely rehabilitated with a new steam turbine, a refurbished boiler, and a new state of the art air quality control system as part of the Company's Metro Emissions Reduction ("MERP") projects (Docket No. E002/M-02-633). It was returned to service in the summer of 2007. It is expected to remain in service throughout the entire resource planning period.

High Bridge Plant
Built in 1923 as a coal-powered operation, the High Bridge plant, along with Riverside in Minneapolis, once formed the hub of Northern States Power Company, a predecessor to Xcel Energy. The original plant was replaced with a new natural gas fired generating facility as another of the MERP projects. The coal-fired plant was retired in 2007 and the new facility came on line in May 2008.

The new High Bridge plant is a natural gas combined-cycle generating facility. A combined cycle plant produces electricity from two sources of energy: 1) Natural gas is used as a fuel in a combustion turbine, and 2) Exhaust heat from the combustion turbine also is used to make steam in a heat recovery steam generator, which drives another turbine and electric generator to produce electricity. Integrating combustion turbine and steam turbine technology provides an extremely efficient production process. The current summer production capacity of High Bridge is 495 MW.

Riverside Plant

Built in 1911, the original coal-powered station was the oldest in the Xcel Energy system. Although construction crews used primitive tools and horse-drawn equipment to build the plant, Unit 1 was up and running within 18 weeks after construction began. A second unit came on line a few weeks later. At the time, Riverside was considered a thoroughly modern steam electric station, and as Minneapolis grew, so did the Riverside plant. Unit 3 was added in 1914, Unit 4 in 1917, Unit 5 in 1921, and two more units in the 1930s. By 1966, Riverside had eight operating units and a net capability of 512 megawatts.

The original plant was replaced with a new natural gas fired facility starting in 2006 as part of our MERP projects, to significantly reduce air emissions and increase electricity production. The coal-fired plant was retired as the new facility, a combined cycle natural gas generation facility with a summer capacity of 484 MW, came on line in April 2009.

Black Dog Plant

The Black Dog Plant is located on the Minnesota River in Burnsville, Minnesota, just south of the Twin Cities. It is a coal- and gas-fired generating station. The original Unit 1 boiler/turbine and the Unit 2 boiler, installed in the 1950s and fired on coal, have been replaced with a natural gas combined-cycle unit (Unit 5). It utilizes state-of-the-art technology for controlling oxides of nitrogen ("NOx") releases. Exhaust heat from Unit 5 powers the Unit 2 steam turbine. The repowering project, completed in the summer of 2002, increased output from the two original units by more than 100 MW, and resulted in greater operating efficiency and cleaner power production.

The current power production capability of the entire plant is 506 MW. Units 2 and 5 are summer-rated at 253 MW. Unit 3, completed in 1955, is 89 MW. Unit 4 is 164 MW and was completed in 1960.

Units 3 and 4 are dual-fuel boilers with steam turbines that currently utilize low-sulfur western coal as the primary fuel. Natural gas is the backup or topping fuel used to obtain maximum generation for both units. Unit 3 and 4 reach the end of their depreciation lives in 2013 and 2014, respectively. In addition, pending environmental regulations are expected to result in the need for significant investments in Unit 3 and 4 to maintain environmental compliance. In this Resource Plan, we provide a comparative analysis of extending the life of the plant or repowering the site as a 680 MW combined cycle facility. Because the repowering project will increase the output of the facility by nearly 400 MW, the life extension analysis also includes the addition of other facilities to meet our overall resource needs. We will present our repowering analysis in the Planned Changes section of this chapter.

Sherburne County ("Sherco") Plant

Sherco is located on the Mississippi River in Becker, Minnesota, which is 45 miles northwest of the Twin Cities. Sherco is our largest fossil fueled plant in terms of steam production, power generation capability and coal consumption. The portion of its total summer capacity owned by Xcel Energy is 1,900 MW. Unit 1 is rated at 697 MW. Unit 2 is rated at 682 MW, and Xcel Energy's portion of Unit 3 is rated at 521 MW. The plant's typical availability factor of 95% is well above the national average of 78%.

All three Sherco units use low-sulfur Western coal from mines in Montana and Wyoming. The plant burns 30,000 tons of coal (three trainloads) every day and more than 9 million tons a year. A rotary car dumper, which turns a rail coal car upside down, unloads one car every three minutes and an entire train in just over six hours.

Sherco Units 1 and 2 were built in the mid-1970s to meet the growing demand for electricity and to reduce the use of older, less efficient plants. The plant was constructed on a 4,500-acre site to accommodate future expansion. A third unit was completed in 1987, which at the time marked the largest construction project ever in the state of Minnesota. Unit 3 is 41% owned by Southern Minnesota Municipal Power Agency.

Unit 3's dry scrubber system, which uses a mist of lime slurry in spray dryers to trap sulfur dioxide, is the world's largest air quality system for a single unit. Units 1 and 2 have wet scrubbers, which use an alkaline spray to capture sulfur dioxide and ash. The plant also installed new wet electrostatic precipitator ("ESP") technology on its two older units to reduce particulate emissions. Sherco employs continuous emissions monitors to ensure it operates within state and federal air quality permit limits. Turbine upgrades totaling approximately 21 MW additional generation capacity are planned for Unit 3 in the 2014 timeframe. Xcel Energy's portion of those upgrades will be approximately 11 MW.

Angus Anson

The Angus Anson plant is located in Sioux Falls, South Dakota. It is a three -unit natural gas peaking facility with summer capacity of 346 MW in total. The Anson station was formally established in 1994, when two peaking units were installed to provide additional generation to the Sioux Falls area. A third, larger combustion turbine was installed at the site in 2005.

Other Natural Gas/Oil Combustion Turbine Plants

We have several natural gas/oil combustion turbine plants on our system.

They include two plants in Wisconsin that are available to run on either natural gas or oil. The first is Flambeau Station and consists of a single 1960s vintage gas-fired combustion turbine. This facility is staffed on a part-time call-in basis. This facility is occasionally dispatched in out of merit order for area voltage support, particularly when low water years reduce the output of nearby Wisconsin hydro plants. We expect to retire this facility in 2012. The second is the Wheaton plant, which consists of 4 dual-fueled (primarily gas) combustion turbines and two oil-only combustion turbines. The combined capacity of these units is 300 MW. Our analysis indicates that retaining the Wheaton units through most or all of the planning period could be economical if they remain reliable.

The Inver Hills plant, located in Inver Grove Heights, Minnesota, includes six 1970s-vintage gas-fired combustion turbines with a combined summer capacity of 282 MW. The Company has concluded that it would be economically prudent to increase inspections and maintenance of these generating units in order to keep them in service throughout the planning period. Although little data exists on the expected reliability of combustion turbines that are more than 30 years old, we hope to retain these units, so long as they remain reliable.

The Blue Lake plant, located in Shakopee, Minnesota, includes four 1970s-vintage oil-fired combustion turbines with a combined summer capacity of 477 MW and two large gas-fired combustion turbines that were installed in 2005 with a combined summer capacity of 310 MW. Similar to the Inver Hills facility, we believe that it may be prudent to try to retain the older oil-fired Blue Lake combustion turbines, using increased inspections.

The Key City plant is located on the same site as the Wilmarth RDF plant in Mankato, Minnesota. Key City consists of four 1960s vintage gas-fired combustion turbines with a combined capacity of approximately 52 MW. We have recently removed Unit 2 from service due to cost-prohibitive repairs. Plant personnel dispatched from the Wilmarth RDF plant currently operate the remaining units. We plan to retire the remaining Key City units in 2013.

The Granite City plant, located in St. Cloud, Minnesota, consists of four 1960s-vintage gas-fired combustion turbines with a combined capacity of 52 MW. At this time we are proposing to retire Granite City in 2018. Because Granite City is identified as a critical resource in our system restoration plan, we will be evaluating alternatives to Granite City prior to retirement.

Nuclear Resources

Monticello Nuclear Generating Plant

The Monticello nuclear generating plant is located within the city limits of Monticello, Minnesota, approximately 50 miles northwest of Minneapolis/St. Paul. Part of the property is on the eastern bank of the Mississippi River in Sherburne County and part is on the western bank in Wright County.

Monticello uses nuclear fuel in a single-unit boiling water reactor to produce on average 564 MW of electricity during the summer. In January 2006, Monticello reached 637 consecutive days of operation, the longest run in plant history, and generated a record 5,070,000 megawatt-hours of electricity, eclipsing its prior record set in 2004.

Monticello received its initial operating license from the NRC in September 1970. The initial license was for a period of 40 years and was scheduled to expire in 2010. In 2007, the NRC renewed the initial license for an additional 20 years. The renewed license expires in September 2030.

On October 23, 2006, the Commission granted a Certificate of Need for up to 30 dry casks to store spent nuclear fuel on-site independent spent fuel storage installation ("ISFSI") to support the additional 20 years of operation.[1] Per Minn. Stat. § 116C.83, subd. 3, the Commission's decision was stayed until June 1, 2007. Figure 6.1 shows the Monticello nuclear generating plant and the ISFSI.

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[1] The use of casks at the ISFSI is intended for temporary storage. While Xcel Energy is not relying on the DOE to begin accepting waste in the near future, eventually, we believe the DOE will honor its contractual and statutory obligations and begin removing the spent fuel from commercial nuclear generating plants. In light of this uncertainty however, we believe it is prudent to plan on storing all used fuel generated at Monticello through the 20 additional years of operation, until 2030.

Figure 6.1
Monticello Plant and ISFSI

Figure 6.1 shows 10 storage canisters that were loaded in 2008. An additional 10 canisters will be loaded in 2013 and the last 10 canisters in 2016.

In November 2008 we filed an application with the NRC to amend the renewed operating license to allow operation at an increased generating capacity of approximately 71 MW. The filing was placed in suspension by the Atomic Safety Licensing Board, to allow NRC staff to address concerns related to two different uprate petitions, including Monticello, raised by the Advisory Committee for Reactor Safety (ACRS) related to containment pressure associated with pump performance. The industry submitted a white paper and the NRC staff recommended that the matter be addressed through specific filings to demonstrate any potential risk and mitigation measures if necessary. In a letter to the NRC staff, the ACRS indicated that potential for modifications to the plant should be evaluated and made where practical. We are working with the NRC to supplement our filing to address the issues and we expect to complete the license proceeding in 2011.

Prairie Island Nuclear Generating Plant

Prairie Island is located within the city limits of Red Wing, Minnesota, approximately 30 miles southeast of Minneapolis/St. Paul. Prairie Island uses nuclear fuel in two two-loop pressurized water reactors to produce on average a nominal value of 550 MW of electrical power per unit. Prairie Island is a highly reliable generation resource. In 2007, Prairie Island's capacity factor was 93.85% and generated a record of nearly 9 million megawatt-hours of electricity, eclipsing its prior record set in 2003.

Unit 1 was initially granted its operating license by the NRC in August 1973, with Unit 2 receiving its initial operating license in October 1974. Unit 1 began commercial operation in December 1973, and Unit 2 began operation in December 1974. Units 1 and 2 are currently licensed by the NRC to operate until August 9, 2013 and October 29, 2014, respectively.

In April 2008, the Company filed an application with the NRC to renew the operating license for the two nuclear reactors at Prairie Island for an additional 20 years, until 2033 and 2034. The Prairie Island Indian Community (PIIC) filed contentions in the NRC's license renewal proceeding in August 2008, which were referred to the Atomic safety Licensing Board for review. The ASLB granted the PIIC hearing request and has admitted seven of the 11 contentions filed. All seven contentions that were originally admitted have been resolved and removed from the ASLB docket. After the NRC issued the final Safety Evaluation Report and the draft supplemental environmental impact statement, the PIIC filed four additional contentions. The ASLB has admitted one of the contentions and has issued a decision denying the other three. If the admitted contention is not resolved, the resulting adjudicatory process is expected to add approximately eight months to the

NRC's standard review schedule, resulting in an anticipated decision in late 2010 or early 2011.

Extending the life of Prairie Island will involve significant additional investment over the next 20 years including replacing the Unit 2 steam generators. Through an extensive inspection and maintenance program, Prairie Island has been able to operate its steam generators longer than plants of similar vintage. However, over time, the tubes and support plates of the steam generators corrode. Projections of steam generator tube degradation indicate that while the plant safety can be maintained without compromise, the continued loss of efficiency due to declining performance of the generators could make the plant uneconomical. The Unit 1 steam generators were replaced in 2004 and the Unit 2 steam generators are scheduled for replacement in 2013. The steam generators are custom order items which require significant manufacturing lead time.

Although we are investing significant capital in extending the lives of our nuclear plants, the cost of life extension is substantially lower than the capital and operating costs of alternatives to provide over 1500 MW of base load energy and capacity.

On December 19, 2009, the Commission granted a Certificate of Need for up to 35 additional dry casks to store spent nuclear fuel on-site independent spent fuel storage installation ("ISFSI") to support the additional 20 years of operation.[2] Per Minn. Stat. § 116C.83, subd. 3, the Commission's decision was stayed until June 1, 2010. Figure 6.2 shows the Prairie Island nuclear plant and the adjoining ISFSI.

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[2] The use of casks at the ISFSI is intended for temporary storage. While Xcel Energy is not relying on the DOE to begin accepting waste in the near future, eventually, we believe the DOE will honor its contractual and statutory obligations and begin removing the spent fuel from commercial nuclear generating plants. In light of this uncertainty however, we believe it is prudent to plan on storing all used fuel generated at Prairie Island through the 20 additional years of operation, until 2033/2034.

Figure 6.2
Prairie Island Plant and ISFSI

Planned Changes at Thermal Generation Facilities

Black Dog Units 3 and 4 Repowering

As noted above, Black Dog Units 3 and 4 have operated for over 50 years. In addition, pending federal regulations requiring emissions control for mercury and other hazardous air pollutants are expected by 2014. In this Resource Plan we need to make important decisions about the future of units 3 and 4.

The Black Dog Plant is located on the Minnesota River in Burnsville, Minnesota. It is surrounded by Xcel Energy's largest load area, the Minneapolis-St. Paul metro area, and lies in close proximity to both the 345 kV and 115 kV transmission systems.

In addition to the 270 MW of capacity represented by Units 3 and 4, our system needs indicate that we will require approximately 720 MW of capacity between 2015 and 2018. As a result, our Black Dog evaluation also included the examination of alternatives that would supply additional capacity and energy to meet our needs. Should we decide to retire units 3 and 4, the reduction of 270 MW of generation capability will need to be replaced, and both the unmet need and the 270 MW of reduced generation capacity will have to be made up by other new resources.

In our repowering study, we considered three options for the disposition of Black Dog. The options we studied are:

- investing in the life extension and environmental control retrofits necessary to continue to operate Units 3 and 4 on coal,
- retiring Units 3 and 4 and constructing a 680 MW combined cycle generation facility on the Black Dog site, and
- retiring Units 3 and 4 and adding necessary resources elsewhere on the NSP system

Based on our evaluation of the three alternatives, we have determined that the best available option would be to retire Units 3 and 4 and construct a new natural gas combined cycle facility in 2016.

Black Dog Project Alternatives

A number of options, scenarios, and arrangements were investigated for replacement of the existing coal fired generating capacity and an increase in overall generation capacity to meet our full resource need.[3]

Black Dog Life Extension

Long term continued operation of the existing units 3 and 4 would require significant retrofit of environmental controls. For planning purposes we assume that new federal mercury emission limits will take effect by the end of 2014, although limits and implementation dates have not been set to date. In order to achieve high levels of Mercury reduction, a combination of Activated Carbon Injection (ACI) and a Fabric Filter dust collector would be needed, similar to the approach currently being utilized at the Company's Sherco Unit 3 and King facilities. In order to be able to continue coal operations for an additional 20 years, emissions of SO_2 and NO_x will also be reduced through addition of flue gas scrubber and Selective Catalytic Reduction technology will also be installed, similar to what was recently installed at the King Station.

In addition to the environmental controls needed to bring the units into compliance with current and new regulations, to extend the life of units 3 and 4 we will also need to make investments to maintain and replace aging plant components. In this scenario, we ask Strategist to select generic generation units to place elsewhere on the NSP system, optimized to meet load and capability requirements. To supplement continuing to operate Black Dog units 3 & 4 on coal, Strategist selected nine combustion turbines, installed between 2017 and 2025, and a combined cycle generation unit, installed in 2025.

[3] When considering building or expanding a fossil fuel-fired generation facility, Xcel Energy is required to consider as an alternative a proposed facility satisfying the requirements of the Innovative Energy Project statute, Minn. Stat. § 216B.1694, subd. 2(a)(5). The Commission previously found that a proposed Innovative Energy Project was not in the public interest for Xcel Energy's ratepayers and the Minnesota Court of Appeals affirmed. At this time, no proposed facility satisfying the requirements of the statue have been proposed to Xcel Energy for consideration. Minn. Stat. § 216B.1694, subd. 1. In any case, our Resource Plan shows a need for intermediate and peaking capacity and energy, rather than the baseload capacity and energy associated with a project that satisfies the requirements of the statute.

Black Dog 3 and 4 Repowering

Under the Repowering project, unit 3 and 4 operation would be discontinued on coal some time in 2013, but would still be available to generate using natural gas as a boiler fuel. While for economic reasons the plant is unlikely to dispatch as often on natural gas as it did on coal, switching to natural gas will allow the current capacity to remain available throughout the construction period, and continue to generate energy when it is needed. A combined cycle facility would be constructed in the area reclaimed from the existing coal storage yard by the beginning of 2016.

The combined cycle facility would be based on "F" class combustion turbines, 3-pressure reheat heat recovery steam generators with supplemental duct firing for additional peak generation capability, and a single condensing steam turbine. Facility cooling would utilize the cooling water allocated to the existing coal units. Natural gas would be utilized as the fuel supply for the combustion turbines. The electrical power output will be connected directly to the 345 kV transmission lines which run adjacent to the Black Dog plant.

Development of the plant would require that a large amount of fill be brought in to raise the elevation of the land currently occupied by the coal storage area. The coal yard would be reclaimed and clean structural fill would be utilized to raise the elevation above the 100 year flood plain. The fill would be placed within flood control berms previously evaluated by Corps of Engineers and therefore would not have any impact on drainage in the Minnesota River Valley.

Emissions from the new facility would be significantly lower than from the existing coal fired units. Preliminary estimates are that NO_x, SO_2, and Hg emissions will be reduced 98 to 99% on an annual basis. This project would result in a total net increase of 410 MW in generation capacity, and its emissions could be netted against the current emissions at Black Dog.

As referenced in Table 4.1 of Chapter 4, Strategist selects seven combustion turbines installed between 2020 and 2025, and a combined cycle generation unit in 2025 to supplement the Black Dog combined cycle unit installed in 2016.

Retirement Option

Under this scenario, we converted units 3 and 4 to natural gas at the end of 2014. Between 2016 and 2018, we retired units 3 and 4 and allowed the system to select new generic resources to both replace the output of those units and meet any additional resource needs. Strategist selected 10 combustion turbines, to be installed between 2016 and 2025, and a combined cycle unit installed in 2025.

Modeling Results

We modeled these three alternatives in Strategist and evaluated their PVRRs. Our results indicate that the repowering alternative is $12 million less expensive than the Black Dog Retirement option, primarily due to the benefits of re-using an existing site, water systems, offices and other facilities. In addition, this PVRR difference does not capture additional benefits such as use of existing transmission capacity and existing natural gas pipeline infrastructure, which are not modeled as part of generic units in Strategist.

The Black Dog Repowering project is also over $600 million less expensive than the Black Dog Life Extension alternative. See Table 6.1.

Table 6.1
PVRR Comparison of Black Dog Repowering to Alternatives
($000s)

	PVRR	Difference from BD Repowering
Black Dog Repowering	$90,702,859	
Black Dog Retirement	$90,714,935	+ $12,076
Black Dog Life Extension	$91,325,767	+ $622,909

Additionally, we compared the Black Dog Repowering project against the Black Dog Life Extension project across a range of sensitivities. [4]

Table 6.2
PVRR Differences
($000s)

	Plan with BD Repowering	BD Life Ext Diff from Plan
Base	$90,702,859	$622,909
High Gas	$92,184,890	$479,969
Low Gas	$89,192,022	$763,035
High CO2	$96,328,301	$887,846
Low CO2	$88,058,510	$496,443
Late CO2	$88,445,801	$526,183
No CO2	$85,087,884	$356,878
High Load	$96,466,131	$679,173
Low Load	$86,582,937	$582,730
DSM 1.5%	$90,702,859	$622,909

As shown in table 6.2, the PVRR's of the Repowering project are much lower than those of the Life Extension project across all sensitivities.

Our modeling shows that the primary need for additional capacity and energy during the planning period is for additional intermediate and peaking resources. Strategist consistently selects combustion turbines and combined cycle generation as the least-cost generation to meet our future capacity needs. Converting Black Dog to natural gas is consistent with the identified profile of our future needs.

[4] Since the Black Dog Repowering project and Black Dog Retirement option both rely on natural gas generation, the sensitivity analyses would have affected both very similarly, and would not provide additional insight, so we did not include that comparison, or the emissions comparison, here.

Table 6.3 shows the Black Dog Repowering option to be superior to the life extension alternative for a number of critical environmental emissions. Given the abundance of federal emissions regulations that are pending over the next few years (discussed in the Environment chapter, Chapter 9 of this Plan), reducing our environmental emissions reduces the risks of compliance and operational challenges associated with providing service to our customers.

Table 6.3
Emissions Differences between the Black Dog Repowering project and the Black Dog Life Extension Alternative
(Tons Emitted 2010-2049)

	BD Life Extension	BD Repowering Difference from BD Life Ext
SOx	1,031,611	-10,423
NOx	714,375	-10,449
CO2	1,006,904,828	-36,984,356
CO	144,675	-7,382
PM10	114,791	-8,019
VOCs	20,689	252
HG	32,855	-2,583

Benefits of the Repowering Project

In addition to the cost savings and emissions reductions for repowering the Black Dog facility, there are a number of other benefits to our proposal. First, the opportunity to utilize a brownfield site and existing transmission to renew and expand our fleet avoids the proliferation of generating sites and transmission corridors in the state. The site also has substantial infrastructure available for use at the new facility, such as natural gas pipeline infrastructure, water systems, offices and other facilities.

The operating flexibility of the combined cycle facility would be significantly better than the existing coal units, which will improve the ability of NSP to manage the variability associated with significantly increased wind generation capacity on our system.

Cost and Schedule
The Black Dog repowering project is expected to cost approximately $600 million, including the demolition and salvage of the current units 3 and 4. Once units 3 and 4 are removed, there may be room on the site for one or two additional combustion turbines. Our current plan would be to have the combined cycle facility operational by the beginning of 2016, although changes in our forecasted needs could move the project to 2017 or 2018, or to be phased in over that period.

If the project is approved with an in-service date of 2016, we propose to discontinue coal firing at Units 3 and 4 in 2013, continuing to make the units available on natural gas. In order to meet this schedule, we would prepare the necessary applications for regulatory approval by early to mid-year 2011.

Sherco Environmental/Uprate Project
As part of our 2007 Resource Plan, we indicated that we were planning on upgrading the capacity of all three units at Sherco. Based on the economic conditions that occurred during the later half of 2008, we withdrew our plans for capacity upgrades at Sherco Units 1 and 2. We are still moving forward with the capacity upgrade of Unit 3 which will add 21 MW in late 2011. Our ownership share will be approximately 13MW additional capacity.

We also completed the installation of the mercury control system at Sherco Unit 3 in 2009. We filed plans for mercury controls at our wet scrubbed units, Sherco Units 1 and 2 in December 2009. Because of the uncertainties around federal requirements described in some detail in the Environment chapter, chapter 10 of this Resource Plan, our plan proposes that we continue to test technologies and install either a sorbent injection system similar to that installed at Sherco Unit 3 and being installed at

A.S. King by December 31, 2014 or one of the emerging technologies we are now testing. Our plans for Sherco Units 1 and 2 has been reviewed and approved by the Minnesota Pollution Control Agency ("MPCA"). The MPCA recommendations will be reviewed by the Commission as part of the Commission's decision making-process on the project.

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Sherco 1 and 2 Life Cycle Management Study

Our Sherco Units 1 and 2 will be 40 years old and reach the end of their book life (i.e., fully depreciated) in 2023. We propose to conduct a comprehensive life cycle management study over the next two to three years to evaluate the costs and benefits of continuing to operate the plants.

These Sherco units comprise more than 50% of our total coal generation after the retirement of Black Dog units 3 and 4. Between now and 2023, we expect greater clarity to emerge regarding the costs and regulations surrounding the operation of coal-fired generation in the future. Our life cycle management study will examine the types of investments that need to be made to increase the units' operating lives, as compared with the costs of replacing the units with alternative generating facilities. As carbon and other environmental regulations become more certain, we will incorporate those regulations into our analysis. Depending on how federal pollution control policy unfolds over the next few years, we may be faced with significant investment decisions before all of the emission and carbon policy direction has been established.

We intend to file the preliminary results of our Sherco Life Cycle Management Study with our next Resource Plan. Subsequent resource plans will contain updates of the study, eventually leading to a recommendation on what to do with these units.

Monticello Extended Power Uprate Project

The Monticello extended power uprate ("EPU") was approved by the Commission on January 8, 2009. The Monticello EPU will add 71 MW by: (1) increasing the amount of the steam produced in the reactor; and (2) improving the balance-of-plant equipment that converts the steam into electricity. To obtain the higher steam flow, the reactor will be operated at a higher thermal power level. The additional heat is achieved primarily by increasing the number of new fuel assemblies replaced in the reactor core at each refueling. This is done without increasing the operating reactor pressure and without changes to the fuel design or fuel design limits.

The goal of the Monticello EPU Project is to increase the thermal power to 120 percent of the Original Licensed Thermal Power. This power uprate would increase reactor power from the current licensed thermal power level of 1775 MW thermal ("MWt") to 2004 MWt. The corresponding increase in net generator output is estimated at 71 MW for a nominal net electrical output delivered to the grid of 656 MW electrical ("MWe").

The project was designed to be implemented in two phases corresponding with two scheduled refueling outages in 2009 and 2011. Work was performed during the 2009 refueling outage, however the NRC has not yet completed its review of our application to modify the operating license. We continue to work with the NRC on its review and expect the NRC will issue a new operating license in the second half of 2011. This will allow us to complete the implementation of the EPU in 2011 and have the full 71 MW of additional capacity available.

Prairie Island Extended Power Uprate Project

The Prairie Island EPU was approved by the Commission on December 18, 2009. The Prairie Island EPU will add 82 MW per unit or 164 MW by: (1) increasing the thermal power produced by the reactors, which will increase the amount of steam produced in the steam generators; and (2) improving the balance-of-plant equipment that converts the steam into electricity. A higher thermal power level is achieved by increasing the amount of uranium in the reactor core, which will be accomplished by using fuel assemblies that contain slightly larger uranium pellets. General operation of Prairie Island will not change after implementation of the extended power uprate. The goal of the extended power uprate at Prairie Island is to increase the thermal power for Unit 1 and Unit 2 from the current licensed thermal power level of 1650

MWt to 1805 MWt. The corresponding increase in net generator output is estimated to be 82 MW per unit, or 164 MW in total.

In general, power uprates in pressurized water reactors do not require significant modifications to the reactor or the nuclear steam supply system of the emergency core cooling system. However, the balance-of-plant systems that convert the steam produced in the steam generators to produce electricity will need significant modifications. These modifications are currently scheduled to be completed on Unit 1 during the 2014 refueling outage and on Unit 2 during the 2015 refueling outage.

Operating the plant at a higher thermal power will also require an amendment to the plant's operating license by the NRC. We intend to file an amendment for the EPU shortly after the NRC approves our request to extend the current operating license an additional 20 years.

Heat Rate update

In Docket No. E-999/CI-06-159 (*In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005*), the PUC required the Company to file information on the fossil fuel efficiency ("heat rate") of our generation units, and actions we are taking to increase the fuel efficiency of those units.

Heat Rate Data

Heat rate data for the Company's owned generating units is provided publicly in our annual Federal Energy Regulatory Commission (FERC) Financial Report, FERC Form No. 1. We include a copy of the pertinent unit heat rate data from FERC Form No. 1 for 2009 in Appendix E.

Heat Rate Testing

As the Company explained in its 2007 Resource Plan, we formed a Performance Monitoring group in 2000 to measure the heat rates of our generating units and to make specific recommendations for improving plant performance. Since that time the Company has implemented an extensive effort to conduct heat rate tests at our generation units. We have continued this testing over the past several years, as detailed in Table 6.4 below.

Table 6.4
Heat Testing 2005-2009

Plant/Unit	Type of Test	Year
Blue Lake 7 & 8	Heat Rate	2005
Riverside 6 & 7 (coal)	Heat Balance	2005
Sherco 1	Heat Balance	2005
Black Dog 5/2 (CC)	Heat Balance	2006
Inver Hills 2 & 3	Heat Rate	2006
Sherco 3	Heat Balance	2006
Inver Hills 6	Heat Rate	2007
Sherco 2	Heat Balance	2007
High Bridge CC	Acceptance & Baseline Heat Rate	2008
Sherco 1	Heat Balance	2008
King 1	Heat Rate	2009
Riverside CC	Acceptance & Baseline Heat Rate	2009
Sherco 3	Heat Balance	2009

In addition, we have completed numerous component reports on boilers, air heaters, cooling towers, and pre-outage enthalpy drop tests on steam turbines, which are not listed in this table. These component tests factor into our assessment of the condition of these components and how their respective performance levels will impact the overall efficiency of a given generating unit.

Looking forward, the Company plans to continue our cycle of heat rate testing at our generation units.

Heat Rate Improvement Projects

As part of its review, the Performance Monitoring group identifies potential heat rate improvement opportunities and validates actual performance enhancements as part of its heat rate testing and reporting protocol. The Company does not look at heat rate improvements in isolation when considering plant improvement projects, but rather, we perform a collective assessment of potential safety, efficiency, and environmental performance improvements as well as overall economics in developing our generation asset management objectives.

This more expansive, collective approach to asset management and budgeting has lead to the identification of additional opportunities to improve the management and efficiency of our generation assets, including the implementation of the Black Dog combined cycle project, MERP projects at the High Bridge, Riverside, and King plants, and the development of the proposed Sherco upgrades project. All plant uprate projects have or will improve the thermal efficiency of generation and reduce emission rates at those plant sites.

Updated Nuclear-Related Reports

Minnesota Statute 3.8851 Subd. (4) requires the three nuclear reports listed under Minn. Stat. Section 116C.772 Subdivisions 3 to 5, the worker transition plan, a nuclear phase-out plan and a TN-40 cask decommissioning plan, to be filed with the

Commission with the Company's Resource Plan. The worker transition plan has been updated and is included in Appendix C. The new plan incorporates the fact that Xcel Energy as the sole remaining NMC member, recently integrated NMC back into Xcel Energy. The integration was discussed in a filing we made with the Commission on April 14, 2008 in Docket No. E002/AI-99-1652. At this time the NRC licenses for Monticello and Prairie Island and all employees have been transferred back to the Company.

A copy of an updated TN-40 cask decommissioning plan is included in Appendix C. The updated decommissioning plan is based on the supplemental information and analysis performed in the 2008 Decommissioning Cost Study used in support of our 2009 Nuclear Plant Decommissioning Accrual filing in Docket No. E002/M-08-1201.

The nuclear phase-out plan assumes phasing out Monticello in 2030, upon the expiration of its renewed operating license and Prairie Island in 2033 and 2034 for Unit's 1 and 2 respectively. The NRC approved the extended operating license of Monticello on November 8, 2006 authorizing the plant to operate until 2030 and the Commission granted the dry casks storage necessary to support the extended operation of the plant until 2030 on October 23, 2006.

The Commission granted the additional dry cask storage necessary to support the continued operation of Prairie Island until 2033/2034 on December 18, 2009 and we are awaiting final approval on the renewed operating licenses from the NRC. The application to the NRC to renew the operating licenses was filed on April 15, 2008. The final Safety Evaluation Report was issued on October 16, 2009. The final Supplemental Environmental Impact Statement is expected to be issued in the near future. There is currently only one open contention before the Atomic Safety and Licensing Board ("ASLB"). Xcel Energy is challenging that contention. If the contention is not resolved, the resulting adjudicatory process will add approximately eight months to the NRC's standard 22 month review. The Company expects the NRC to issue a decision approving the license extension during the first half of 2011.

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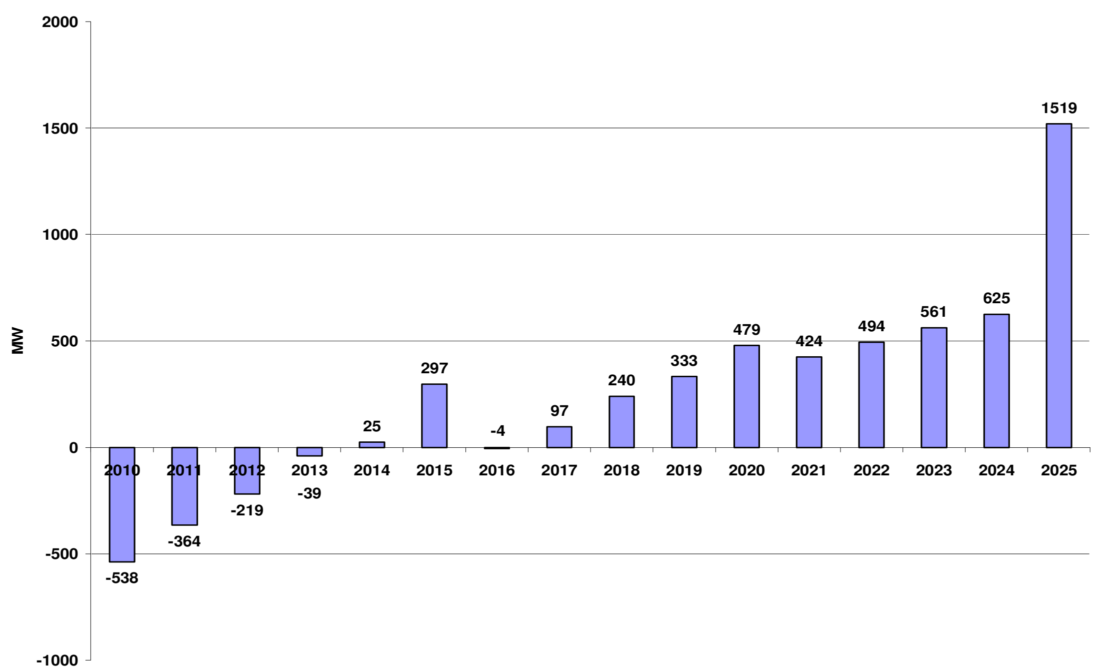
The Company has all necessary state and federal approvals to continue operating the Monticello nuclear generating plant, and has all state approvals to continued operations at Prairie Island. We are now only awaiting the final NRC approval of the Prairie Island operating license extension. Accordingly, the phase-out plan for our nuclear plants does not occur within the planning horizon of this Resource Plan. This Resource Plan assumes continued operation of the nuclear plants for the duration of the plan. As the phase-out dates of 2030 for Monticello and 2033 and 2034 for Prairie Island get closer, future Resource Plans will address the phase-out and replacement of the capacity and energy provided by the nuclear plants.

Contingency Planning/Peaking Resources

Once we have implemented our action plan items, our forecast indicates that we will require around 450 MW of additional capacity resources between 2015 and 2020. Our resource needs after we implement the nuclear upgrades, Manitoba Hydro, Black Dog and planned wind are shown in Figure 6.3

Figure 6.3
Resource Needs after Action Plan Implementation



However, as we noted in Chapter 3 of this plan, our forecast is uncertain. It is possible that the demand level predicted in this forecast will not fully materialize; on the other hand, strong economic recovery could result in higher capacity needs over that time period. In keeping with our overall approach in the Resource Plan, we believe it is best to maintain flexibility with respect to adding peaking resources to our system over the next 10 years.

Essentially, we have three options to meet our peaking needs: short-term, mid-term and long term capacity. First, we can utilize seasonal short-term capacity purchases from the market. Seasonal short-term capacity is generally lower cost than longer term capacity purchases, but typically does not cap the price of energy that may be delivered under the purchase. As such, it is risky to rely on short-term capacity for a significant portion of the Company's needs. Short-term capacity is typically used to fill gaps in resource needs in between major additions, and to respond quickly to changing market conditions.

Mid-term capacity purchases also come from the market, but these bilateral transactions typically have terms of 2-5 years and are more likely to have some provision to cap the cost of energy from the contracted facility. Mid-term capacity is typically used to defer the addition of a long-term resource for a few years to have time to develop and construct a project, or to defer investments to a later time period. In recent years there have been fewer opportunities to purchase mid-term capacity as many utilities were predicting higher growth and offering capacity resources only on a short-term basis since there was less excess capacity available in the market. However, the recent downturn has reduced most utilities' base demand and energy requirements and increased the amount of excess capacity expected to be available for longer periods of time.

Long-term capacity can be either constructed or purchased, and is used to meet ongoing capacity needs. The Company can construct and own its long-term resources, or purchase them from the market. Long-term purchases are typically more than 20 years in length and usually tied to a specific unit. Frequently Xcel Energy enters into tolling arrangements for its long-term contracts, purchasing the fuel for the facility to generate energy and paying the facility owner a conversion fee to cover variable O&M charges.

In previous resource plans, we have planned for a certain amount of short-term capacity to meet peaking needs and hard-coded it into the model. As capacity markets have changed through MISO, we adopted a different approach. Instead of relying on short term to meet some portion of identified need, we have instead offered short-term capacity in the model as an alternative to adding longer term generic resources. This allows the model to fill in with short-term capacity if the deficit in a given year is smaller than the size of a new unit, or when a short-term approach appears to be more cost effective.

In this Resource Plan, we show a deficit of 300 MW in 2015 which is largely eliminated in 2016 when the Black Dog CC is completed. Because this appears to be only a one-year deficit, we are currently proposing to fill it with short-term capacity purchases. As that need begins to grow again as early as 2017, we may need to consider adding a CT or other long-term peaking resource.

Given the uncertainty of our forecast, we are proposing to continue to monitor our deficits in 2015 and beyond as we update our forecast. If we see significant changes that call for an early implementation of long-term peaking resources, we will notify the Commission of this need and proceed with either an RFP or a proposal to construct our own resources. We will also explore all of the available options for mid-term capacity resources and acquire such resources to the extent that they offer reduced risk and cost to our customers.

To prepare for our eventual need for longer-term peaking resources, the Company is evaluating the possibility of conducting preliminary engineering and permit preparation work for adding a new combustion turbine at one or more or our existing sites. Some of these sites have adequate space, infrastructure and transmission for additional units, and could potentially be redeveloped in conjunction with retiring aging oil or small natural gas turbines on those sites. Conducting this work prior to the actual need to propose a new facility will allow us to act quickly in the event of an unexpected increase in the demand forecast.

In the longer term, the Company will be scoping the availability of new green field sites for capacity expansion. We are particularly interested in sites that have good proximity to natural gas lines and transmission lines. There are some sites in southwestern Minnesota that may be particularly good for peaking resources, as they can utilize transmission in that area when it is not being used to transmit wind energy. Longer-term development of a green field site will allow us to add facilities to replace aging units and meet growing demand in the latter part of our plan

.

Conclusion

Our existing thermal generation fleet has served the Company and our customers well over the years. Even with upgrades, environmental improvements and other life extending measures, these plants will continue to be low cost resources for our customers. Our analyses have indicated that repowering the Black Dog plant, continuing to pursue life extension and the extended power uprate projects at both the Prairie Island and Monticello nuclear power plants and completing the Sherco environmental and capacity projects are in the best interest of our customers and the environment.

414 Nicollet Mall
Minneapolis, Minnesota 55401

August 2, 2010 **-- Via Electronic Filing --**

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: 2010 RESOURCE PLAN
DOCKET NO. E002/RP-10-825

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy," "Company"), is pleased to submit our 2010 Resource Plan to the Minnesota Public Utilities Commission for consideration and approval. This Plan covers the period 2011 to 2025 and it identifies how we propose to meet our customers' needs for generation capacity and electrical energy during the planning period.

Over the last several years we have worked closely with our regulators to establish a program to modernize our generating fleet and improve environmental performance, extend the lives of our nuclear plants and increase their production, extend our purchases from Manitoba Hydro, expand our wind powered resources, expand the transmission network, and help our customers conserve more and more energy. These efforts put us in good position to provide reliable and economical service into the future. As a result, changes in resource acquisitions are minimal in this filing.

However, as we submit this Plan we recognize there are emerging issues in our economy and our industry that make it important that we maintain flexibility to adjust as we continue the course that has served us well.

Our five-year action plan consists of the following principal elements:

- Fully implement the previously established goal of 1.3% DSM by 2013 and work with stakeholders to increase DSM to 1.5%

- Issue an RFP for up to 250 MW of wind power to be developed by the end of 2012. Make or defer selections based on a thorough evaluation of cost effectiveness and other benefits of the proposals received.
- Replace the remaining 270 MW of coal fired generation capacity at Black Dog with a 680 MW natural gas, combined cycle unit in 2016.
- Develop a plan over the next several years to update or replace Sherco 1 and 2 in light of changing environmental regulations.
- Develop a contingency plan to add peaking resources if needed to respond to changing economic conditions and consumer demand.
- Continue efforts to ensure sufficient transmission is available to meet future load, maintain system reliability and effectively integrate new generation.

The Company will continue to work with stakeholders to ensure that our resource plans and accompanying costs are thoroughly understood and implemented effectively. Implementation of this Plan will allow us to meet growing customer needs, significantly reduce carbon and other emissions, and maintain reliable service at reasonable rates. We welcome dialogue with stakeholders and look forward to the Commission's consideration of our Plan.

Enclosed are the original and 15 copies of this filing. Copies have also been served on the Department of Commerce, the Office of the Attorney General – Residential Utilities Division, as well as parties to our most recent Resource Plan. We have also added those from our Renewable Energy Plan docket to this service list as well as representatives from the Commissions of neighboring states. Interested parties will soon be able to obtain copies from our web site at www.xcelenergy.com. We expect to have the filing posted on our web site early next week.

Please contact me at (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES ALDERS
DIRECTOR REGULATORY ADMINISTRATION
GOVERNMENT AND REGULATORY AFFAIRS

Enclosure
c: Service List

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

March 15, 2011

Dr. Burl W. Haar - VIA ELECTRONIC FILING -
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT
DOCKET NO. E002/CN-11-184

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") is pleased to submit to the Minnesota Public Utilities Commission ("Commission") for consideration this Application for a Certificate of Need for the Black Dog Generating Plant Repowering Project. Commission approval will allow us to increase the electrical generating capabilities of the Minnesota plant by approximately 450 MW (from a current capacity of about 250 MW to about 700 MW). The Certificate of Need application is submitted pursuant to Minn. Stat. § 216B.243 and Minn. R. 7849 and demonstrates that the project is cost-effective, provides significant environmental benefits, and adds to our ability to quickly respond to intermediate and peaking needs.

Increased capacity will be achieved through the repowering of the existing coal fired units to a larger natural gas fired combined cycle facility. On August 2, 2010 we filed our 2010 Resource Plan (Docket No. E002/RP-10-825), which indicated that even after including the demand-side management and renewable requirements of 2007 legislation, we are projecting a deficit starting in 2014. Additionally we stated a need for intermediate and peaking facilities to follow our wind generation resources. We also indicated that we would study the need for repowering our Black Dog facilities. This CON is as a result of that study. We submit this application as one element of our resource plan. Approval of this application will not only provide needed resources, it will also add environmental benefits and provide a valuable variable resource with load following capabilities.

The Company intends to file the accompanying Site and Route Permit Application in early-May.

Minn. R. 7849.0210, subp. 1 establishes an application and processing fee of $10,000 plus $50 for each megawatt of plant capacity, plus such additional fees as are reasonably necessary for completion of the evaluation of need for the proposed facility. The proposal will increase the generating capacity at the Plant site by 450 MW, resulting in an estimated total fee of $32,600. A check in that amount accompanies our application.

Information in Appendix H of this filing has been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). A separate trade secret version of Appendix H will be filed electronically and mailed to those parties that are eligible and request paper service. In particular, the cost information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Disclosure of the trade secret provisions would have a detrimental effect by providing valuable information not otherwise readily ascertainable and from which could be obtained economic value.

We are serving the Office of the Attorney General and the Office of Energy Security. A filing summary will be served on parties on the attached miscellaneous service list and to those parties to the Company's last general rate case. Copies of our Application can be obtained from the Xcel Energy web site at www.xcelenergy.com.

Please contact Sara Cardwell at sara.j.cardwell@xcelenergy.com or (612) 330-7975 if you have any questions regarding this filing.

Sincerely,

/S/

Scott M. Wilensky
Vice President
Regulatory Affairs

Enclosures

c: Service Lists

APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG REPOWERING PROJECT

PUC Docket No. E-002/CN-11-184

March 15, 2011

Submitted by
Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT

DOCKET NO. E002/CN-11-184

Petition

SUMMARY OF FILING

Please take notice that on March 15, 2011, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or "the Company"), filed with the Minnesota Public Utilities Commission ("Commission") an application for a Certificate of Need ("CON") for the Black Dog Generating Plant ("Plant") Repowering Project ("Project") and the associated transmission necessary for the direct interconnection of the Project.

The Project consists of replacing the coal-fired generating Units 3 and 4 at the Black Dog Plant site with about 700 MW of gas fired, combined cycle, generation located in what is now the coal storage yard at the Plant. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW in 2010. As part of the Project, these units will operate solely on natural gas starting in 2013 and be shut down in 2016 after the new combined cycle facility is placed in service.

This filing also initiates the Alternative Competitive Resource Acquisition process established in Docket No. E002/RP-04-1752. Prospective alternative providers must intervene in support of their own proposal in a contested case proceeding.

Application to the Minnesota Public Utilities Commission
for a Certificate of Need
Black Dog Repowering Project

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APPLICATION FOR CERTIFICATE OF NEED
Content Requirement and Completeness Checklist

Authority	Required Information	Location of Required Content
7849.0120A	Showing that denial would adversely affect adequacy, reliability and efficiency	Chapter 3
1	Demand forecast for type of energy supplied by proposed facility is accurate	Appendix A
2	Effects of applicant's conservation program and state and federal conservation programs	§ 3.1.1, § 4.3.6
3	Effects of applicant's promotional practices on energy demand	§ 3.1.1, § 4.3.6
4	Ability of current facilities and facilities not requiring certificate of need to meet future demand	Chapter 4
5	Effect of proposed facility in making efficient use of resources	Chapter 4, § 7.3
7849.0120B	A more reasonable and prudent alternative has not been demonstrated	Chapter 4
1	Appropriate size, type and timing compared to reasonable alternatives	Chapter 4
2	Cost of facility and of its energy compared to reasonable alternatives	§ 4.4, § 4.5
3	Effects on natural and socioeconomic environment vs. reasonable alternatives	Chapter 4, Chapter 6, Chapter 7
4	Expected reliability of facility compared to reasonable alternatives	Chapter 4, Appendix B

Authority	Required Information	Location of Required Content
7849.0120C	Project benefit society by protecting the natural and socioeconomic environment, including human health, considering:	Chapter 6, Chapter 7
1	Relationship of facility to overall state energy needs	Chapter 7, Chapter 8
2	Effects of facility on natural and socioeconomic environment compared to not building facility	Chapter 7
3	Effects of facility inducing future development	§ 7.7
4	Socially beneficial uses of the output of the facility, including to protect or enhance environmental quality	§ 7.5
7849.0120D	Project will comply with relevant policies and regulations of other state and federal agencies and local governments	Chapter 8
7849.0200	Application procedures and timing	Cover Letter
7849.0210	Filing fee to accompany application	Cover Letter
7849.0220	Contents of application	Table of Contents; Content Requirements Checklist
7849.0230	Draft environmental report	Not applicable to LEGF; Prepared by OES using information provided
7849.0240	Need Summary and Additional Considerations	Chapter 1
7849.0240, Subp. 1	Need summary contains major factors that justify need for facility	Chapter 1

Authority	Required Information	Location of Required Content
7849.0240, Subp. 2A	Additional considerations address socially beneficial uses of facility output, including uses to protect or enhance environmental quality	Chapter 4, Chapter 6, Chapter 8
7849.0240, Subp. 2B	Promotional activities that may have given rise to demand	§ 3.1.1, § 4.3.6
7849.0240 Subp. 2C	Effects of the facility in inducing future development	§ 7.6, § 7.7
7849.0250	Description of proposed LEGF and alternatives	Chapter 4, Chapter 5
A	Description of the facility, including:	Chapter 5
1	Nominal generating capability and economies of scale on the facility size and timing	§ 4.4, §5.5, §5.6, Table 5-3,
2	Anticipated operating cycle including expected annual capacity factor	§ 5.11, Table 5-3
3	Type of fuel used, including reason for choice of fuel, availability of fuel and alternative fuels, if any	Chapter 4, § 5.7
4	Anticipated heat rate of the facility	Appendix H
5	Anticipated areas where the proposed facility could be located	§ 5.3
B	Discuss alternatives available	Chapter 4
1	Purchased power	§ 4.3.2, § 4.3.3
2	Increased efficiency of existing facilities, including transmission lines	§ 4.3.1, § 4.3.4
3	New transmission lines	§ 4.3.4

Authority	Required Information	Location of Required Content
4	New generating facilities of a different size or using a different energy source as fuel	§ 4.3.5, § 4.3.7, § 4.3.8, § 4.4
5	Any reasonable combinations of the alternatives listed in items 1-4	§ 4.2, § 4.3, § 4.4
C	For the facility and for each alternative in B that could provide electric power at the asserted level of need, discuss:	§ 4.4
1	Capacity cost in current $/kW	Appendices B & H
2	Service life	Appendix B, Table 5-3
3	Estimated average annual availability	§ 5.11, § 5.12, § 5.13, Table 5-3, Appendix B
4	Fuel costs in current $/kWh	Appendices B & H
5	Variable operating and maintenance costs in current $/kWh	Appendices B & H
6	Total cost in current $/kWh	Appendices B & H
7	Estimated rate impact, system wide and in Minnesota, assuming a test year beginning with the proposed in-service date	§ 4.6, Table 4-5
8	Efficiency, expressed for a generating facility as the estimated heat rate, or for a transmission facility as estimated losses under maximum and average loading conditions	Appendices B & H
9	Major assumptions in providing the information in items 1-8, including projected escalation rates for fuel costs, O&M costs, and capacity factors	Appendices B & H

Authority	Required Information	Location of Required Content
D	Map showing the applicant's system	Figure 2-1
E	Such other relevant information about the proposed facility and each alternative as may be relevant to need determination	Chapter 4, Appendix B
7849.0270-0290	System load, annual consumption forecast, capacity and conservation program information	Chapter 3, Appendix A
7849.0270	Peak Demand and Annual Consumption Forecast	Appendix A
7849.0270 subpt. 1	Pertinent data concerning peak demand and annual electrical consumption	Appendix A
7849.0270 subpt. 2	Provide the following data for each forecast year:	–
A	Annual consumption by consumers within the MN service area	§ 3.1, Appendix A
B	Estimates of number of consumers and their annual electrical consumption for:	Appendix A
1	Farm, excluding irrigation and drainage pumping	Appendix A
2	Irrigation and drainage pumping	Appendix A
3	Nonfarm Residential	Appendix A
4	Commercial	Appendix A
5	Mining	Appendix A
6	Industrial	Appendix A
7	Street and highway	Appendix A
8	Electrified transportation	Appendix A

Authority	Required Information	Location of Required Content
9	Other	Appendix A
10	The sum of subitems (1) to (9)	Appendix A
C	Estimated power demand at annual peak demand, broken down as in B.	Appendix A
D	System peak demand by month	Appendix A
E	Estimated annual revenue requirement per kW-hr (in current dollars)	Appendix H
F	Estimated average system weekday load factor by month	Appendix A
7849.0270 subpt. 3	Detail of the forecast methodology employed in subpt. 2, including:	Appendix A
A	Overall methodological framework used	Appendix A
B	Specific analytical techniques used, their purpose and where used	Appendix A
C	Manner in which the specific techniques are related	Appendix A
D	Where statistical techniques have been used:	Appendix A
E	Forecast confidence levels or ranges for peak demand and consumption	Appendix A
F	A brief analysis of the methodology used, including:	Appendix A
1	Its strengths and weaknesses	Appendix A
2	Its suitability to the system	Appendix A
3	Cost considerations	Appendix A
4	Data requirements	Appendix A

Authority	Required Information	Location of Required Content
5	Past accuracy	Appendix A
6	Other factors considered significant by the applicant	Appendix A
G	Explanation of discrepancies between current and previous forecasts	Appendix A
7849.0270 subpt. 4	Discussion of the database used in current forecasting, including:	Appendix A
A	Complete list and description of all datasets used in the forecast	Appendix A
B	Clear identification of adjustments made to raw data including:	Appendix A
1	The nature of the adjustment	Appendix A
2	The reason for the adjustment	Appendix A
3	The magnitude of the adjustment	Appendix A
7849.0270 subpt. 5	Discussion of each assumption made in forecast preparation, including:	Application and Appendix A
A	Availability of alternate sources of energy	Chapter 4
B	Expected conversion from other fuels to electricity or vice versa	Chapter 4
C	Future prices and their projected impact upon system demand	Appendix A
D	Subpt. 2 data that is not available historically or internally generated	Appendix A
E	Impact of energy conservation programs upon electrical demand	Appendix C
F	Any other factor considered in preparing	Chapter 3, Appendix A

Authority	Required Information	Location of Required Content
	the forecast	
7849.0270 subpt. 6	Applicant shall provide:	Appendix A
A	Description of coordination of load forecasts with other systems	Appendix A
B	Description of the manner in which forecasts are coordinated	Appendix A
7849.0280	Description of ability of existing system to meet forecast demand	Chapter 3, Chapter 4
A	Discussion of power planning programs applied	Chapter 3, Appendix B
B	Seasonal firm purchases and sales for each utility in each forecast year	Appendix B
C	Seasonal participation purchases and sales for each utility in each forecast year	Appendix B
D	For the summer and winter season of each forecast year:	Appendix B
E	Load generation capacity for purchases, sales, and generation in years subsequent to application (see D 1-13)	Appendix B
F	Load generation capacity for projected purchases, sales and generation in years subsequent to application (see D 1-13)	Appendix B
G	List of proposed additions and retirements in generating capacity for each forecast year subsequent to application	Appendix B
H	Graph of monthly adjusted net demand and capability; plot of difference between capability and maintenance outages	Appendix B

Authority	Required Information	Location of Required Content
I	Appropriateness and method of determining system reserve margins	Appendix B
7849.0290	Application must include the following regarding conservation programs:	–
A	Party (ies) responsible for energy conservation and efficiency programs	Appendix C
B	List of energy conservation and efficiency goals and objectives	Appendix C
C	Description of programs considered, implemented and rejected	Appendix C
D	Description of major accomplishments in conservation and efficiency	Appendix C
E	Description of future plans with respect to conservation and efficiency	Appendix C
F	Quantification of the manner by which these programs impact the forecast	Appendix C
7849.0300	Consequences of indefinite delay or 1,2, or 3 year postponement	§ 3.5, § 4.4.9
7849.0310	Environmental information requested	Chapter 6, Table 6-1, Table 6-2
7849.0320	Provide data for each alternative that would involve LEGF construction	Chapter 4, Appendix B
7849.0320A	Estimated range of land requirements for the facility and a discussion of assumptions on land requirements, water storage, cooling systems, solid waste storage	§ 6.9, Table 6-4, Appendix B
B	Estimated vehicular, rail, barge traffic generated by construction and operation	§ 5.3, § 5.10, § 6.13

Authority	Required Information	Location of Required Content
	of the facility	
C	For fossil-fueled facilities:	–
1	Expected regional fuel sources for the facility	§ 1.5.1, § 5.9, Appendix B
2	Typical fuel requirement during operation at rated capacity and annual fuel requirement at expected capacity factor	Appendices B and H
3	Expected rate of heat input in Btu per hour at rated capacity	Appendices B and H
4	Typical range of heat value of the fuel (in Btu/lb, Btu/gallon or Btu/1000Cf) and typical average heat value	Appendices B and H
5	Typical ranges of sulfur, ash and moisture content of the fuel	Appendices B and H
D	For Fossil fueled facilities:	–
1	Estimated range of trace element emissions and maximum emissions of SO_2, NO_x, and PM in lbs/hour during operation at rated capacity	Table 6-1, Table 6-2
2	Estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from stack of SO_2, NO_x and PM in micrograms/cubic meter at rated capacity and assuming generalized worst-case meteorological conditions	Table 6-2, § 6.1.1
E	Water use by the facility for alternate cooling systems, including:	§ 5.2, Table 5-3
1	Estimated maximum use, including the	Table 5-3

Authority	Required Information	Location of Required Content
	groundwater pumping rate in gallons/minute and surface water appropriation in cubic feet/second	
2	Estimated ground water appropriation in million gallons/year	Table 5-3, Appendix B
3	Annual consumption in acre-feet	Table 5-3, Appendix B
F	Potential sources and types of discharges to water attributable to operation of the facility	§ 6.4, Table 6-4, Appendix B
G	Radioactive releases, including:	–
1	For nuclear facilities, typical levels	N/A
2	For fossil-fueled facilities, the estimated range of radioactivity released by the facility in curies per year	§ 6.4, Appendix B
H	Potential types and quantities of solid wastes in tons per year at expected capacity factor	§ 6.4, Table 6-4, Appendix B
I	Potential sources and types of audible noise attributable to operation	§ 6.2, Appendix B
J	Estimated work force required for construction and operation	§ 6.14, § 7.6, Appendix B
K	Minimum number and size of transmission facilities required to provide reliable outlet	§ 5.8
7849.0330	The applicant shall provide data for each alternative that would involve construction of an LHVTL.	N/A

Authority	Required Information	Location of Required Content
A	for overhead transmission facilities:	–
1	schematic diagrams that show the dimensions of the support structures and conductor configurations for each type of support structure that may be used	Figure 5-4, Appendix E
2	a discussion of the strength and distribution of the electric field attributable to the transmission facility, including the contribution of air ions if appropriate	§ 6.5
3	a discussion of ozone and nitrogen oxide emissions attributable to the transmission facility	§ 6.1.2
4	a discussion of radio and television interference attributable to the transmission facility	§ 6.8
5	a discussion of the characteristics and estimated maximum and typical levels of audible noise attributable to the transmission facilities	§ 6.2
C	the estimated width of the right-of-way required for the transmission facility	§ 5.8
D	a description of construction practices for the transmission facility	§ 5.10.2
E	a description of operation and maintenance practices for the transmission facility	§ 5.13.2
F	the estimated work force required for construction and for operation and	§ 6.14

Authority	Required Information	Location of Required Content
	maintenance of the transmission facility	
G	a narrative description of the major features of the region between the endpoints of the transmission facility. The region shall encompass the likely area for routes between the endpoints. The description should emphasize the area within three miles of the endpoints. The following information shall be described where applicable	§ 6.10
1	hydrologic features including lakes, rivers, streams, and wetlands	§ 6.10
2	natural vegetation and associated wildlife	§ 6.10
3	physiographic regions	§ 6.10
4	land-use types, including human settlement, recreation, agricultural production, forestry production, and mineral extraction	§ 6.11, § 6.12
7849.0340	Alternative of no facility	§ 4.3.9
A	Expected operation of existing and committed facilities	§ 4.3.1
B	Description of the changes in resource requirements and wastes produced	Chapter 3, § 4.3.1, § 6.4, Table 6-4,
C	Description of possible methods of reducing environmental impact	Chapter 4, Chapter 6
Minn. Stat. § 216B.243	Certificate of Need Criteria	–
Subd. 2	Certificate required for this facility	Chapter 1
Subd. 3	Showing required for construction. In	–

Authority	Required Information	Location of Required Content
	assessing need, the Commission shall evaluate:	
1	Accuracy of the long-range energy demand forecast on which need is based	Chapter 3, Appendix A
2	Effect of existing or possible conservation on long-term demand	§ 3.1.1, Appendix C
3	Relationship of proposed facility to overall state energy needs, as described in most recent state energy policy report	§ 8.1
4	Promotional activities that may have given rise to the demand for this facility	§ 3.1.1
5	Benefits of this facility, including uses to protect or enhance environmental quality, increase reliability of energy supply	Chapter 6, § 7.1
6	Possible alternatives for satisfying demand, including increased efficiency and upgrading existing generation, load-management and distributed generation	Chapter 4
7	Policies, rules and regulations of other state and federal agencies and local governments	Chapter 1, Chapter 8
8	Feasible combination of energy conservation improvements, that can replace or compete with the facility	Chapter 3, § 4.3.6
Minn. Stat. § 216B.243 subd. 3a and Minn. Stat. § 216B.2422 subd. 4	Availability of renewable energy alternatives	§ 4.3.8

Authority	Required Information	Location of Required Content
Minn. Stat. § 216B.1694, subd. 2(A)(5)	Innovative energy projects	§ 4.3.8
Minn. Stat. § 216B.2426	Opportunities for Distributed Generation	§ 4.3.7

1 Summary

1.1 Introduction

Pursuant to Minnesota Statutes Section 216BC.243 and Minnesota Rules Chapter 7849, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), is pleased to submit this Application to the Minnesota Public Utilities Commission ("Commission") for a Certificate of Need for the Black Dog Generating Plant ("Plant") Repowering Project ("Project" or "Black Dog Repowering Project") and the associated transmission necessary for the direct interconnection of the Project. The Plant is located in Burnsville, Minnesota as shown in Figure 1-1.

The Project consists of replacing the remaining coal-fired generating Units 3 and 4 at the Plant with about 700 megawatts ("MW") of natural gas-fired, combined cycle, generation located in what is now the coal storage yard. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW for the operating year 2010. As part of the Project, these units will operate solely on natural gas starting in 2013, during construction of the proposed facility, and be shut down in 2016 after the new combined cycle facility is placed in service. The Project results in a cost-effective way to meet customer load growth, removes older coal generation (and its associated emissions profile) from our portfolio, takes advantage of a unique opportunity to maximize the use of and increase capacity at an important existing generating site, and provides significant environmental and economic benefits to our customers and the region.

Repowering the Plant is the most cost-effective way to meet our customers' growing needs.

Our forecasts predict that customer demand will continue to grow at the rate of approximately 1.1% or about 110 MW per year even after consideration of our growing demand side management ("DSM") programs. To maintain reliable service to our customers, the Company needs to add approximately 470 MW of generating capacity to our system in the 2016 timeframe. After evaluating a number of options, our analysis concludes that the additional capacity from repowering Black Dog with a new combined cycle facility is the most cost-effective means to meet our customers' needs.

The Black Dog Repowering Project is a cost-effective means of modernizing our fleet.

The Project allows the Company to retire older, less efficient generation that would require significant investments to continue operating and meet pending environmental performance requirements. Black Dog Units 3 and 4 were constructed in 1955 and 1960 and have served our customers well for over 50 years. Like any aging generating facility, performance has started to decline and we face the increasing risk of major equipment failure. We expect something on the order of $200 million will be required to refurbish and maintain safe reliable operation over the next decade or two. Furthermore the U.S. Environmental Protection Agency ("EPA") is in the process of establishing new air quality performance requirements that could require approximately $200 million in new pollution control equipment on Units 3 and 4.

The Black Dog Repowering Project is the most cost effective way to address the combination of growing demand and aging infrastructure. We can provide more economical power by shutting down Units 3 and 4 and replacing the output with a new state-of-the-art, natural gas, combined cycle facility that also provides additional generating capacity to meet growing customer needs. A new combined cycle power plant operates much more efficiently and will modernize our generating fleet to serve our customers well into the future.

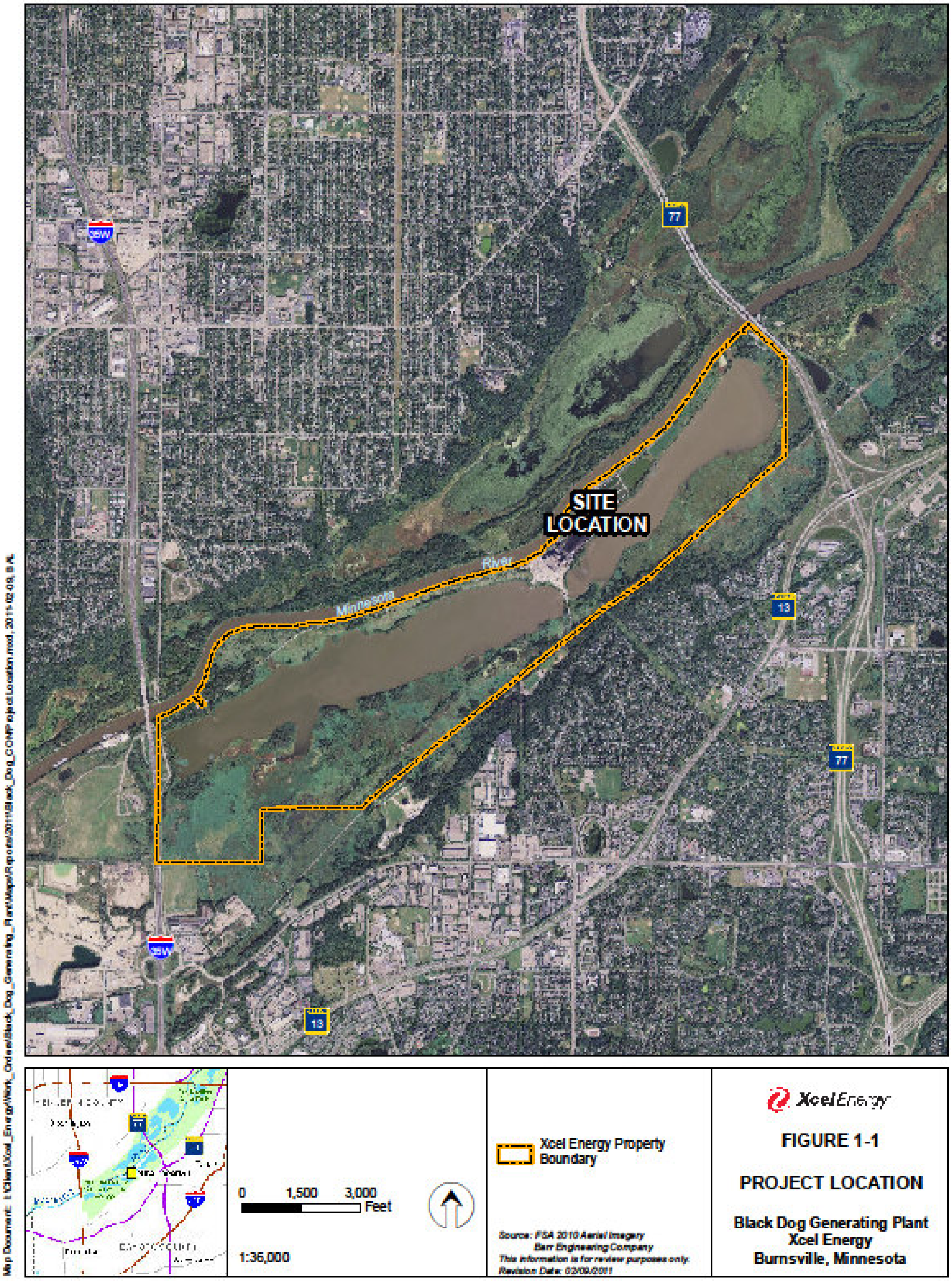
The Black Dog Repowering Project provides important system operating benefits.

Given today's mix of resources on our system, the Project provides a number of system performance and operating benefits. Because of the Plant's close proximity to the metropolitan load center, maintaining generation at this Plant site provides important system reliability and lower transmission line losses. The Project also provides additional operating flexibility to economically respond to fluctuations in customer demand and the variability of wind generation. The Project continues the Company's long and successful strategy of maintaining a diverse mix of generating resources with a variety of primary fuels including gas, coal, nuclear, wind, solar, and hydro, which reduces risks associated with overdependence on any one type of resource.

Repowering at the Black Dog Plant improves system environmental performance and provides a unique opportunity to take advantage of an existing generating site.

This Project will improve the environmental performance of our system. System carbon dioxide ("CO_2"), sulfur dioxide (SO_2"), mercury ("Hg"), nitrogen oxides ("NO_x") and particulate matter emissions will be lower by adding this Project versus any of the other alternatives we studied to meet customer needs. The existing Black Dog site already provides access to transmission lines that pass through the site. The Company holds the necessary transmission system rights to deliver power from this Project to customers upon completion of planned Midwest Independent System Operator ("Midwest ISO") Midwest Transmission Expansion Plan ("MTEP") projects. Since the Project will be developed at an existing site, there is little land use impact. Land use patterns have grown up around the Plant with its substantial buffer of nearly 1900 acres over decades. Conversely, it may be difficult to fully utilize the site in the future if the opportunity to repower the Plant is not taken advantage of today.

Figure 1-1: Project Location



1.2 Regulatory Framework

1.2.1 Certificate of Need

This application begins the Commission's review of our Project and an examination of alternatives. The Project meets the definition of a "large energy facility" as defined in Minnesota Statutes Section 216B.2421, subdivision 2(1) and a "large electric generating facility" as defined in Minnesota Rule 7849.0010(13) and thus requires a Certificate of Need from the Commission before construction can begin. Furthermore, Minnesota Statutes Section 216B.243 requires a Certificate of Need be obtained before increasing the generating capacity of a plant by more than 10% or 100 MW. Our proposal exceeds both thresholds.

To ensure that the Project is the best alternative to meet customers' needs, the Commission has developed procedures that allow other providers the opportunity to offer their alternative generating proposals as part of the Certificate of Need proceeding. *See Order Establishing Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5 and Requiring Compliance Filing*, Docket No. E-002/RP-04-1752 (May 31, 2006); *see also Order Approving Five-Year Action Plan as Modified and Setting Filing Requirements*, Docket No. E-002/RP-07-1572 (Aug. 5, 2009). Under the type of process contemplated in the Commission's prior orders, the Commission will set a deadline for developers to intervene with competing proposals, we recommend June 1st, and notice will be published. If competing proposals are tendered, the Commission's process calls for a hearing to be conducted by an Administrate Law Judge to develop a record that examines the need for generation and the merits of the alternatives. The Company supports following such a process in this instance.

1.2.2 Siting and Environmental Review

Pursuant to Minnesota Statutes Section Chapter 216E, the Project meets the definition of a large electric power generating plant ("LEPGP") and requires a Site Permit. The section of 345 kV transmission required to connect the new units to the transmission system, while entirely contained on the site, meets the definition of a high-voltage transmission line ("HVTL") and we will seek a Route Permit. The Commission must issue Site and Route Permits before construction can begin.

We plan to file a combined Site Permit and Route Permit application by early May 2011. Typically the Commission then consolidates the Certificate of

Need, siting and routing proceedings. Since we are proposing to repower at an existing site, the siting process places primary emphasis on the examination of the potential environmental and land use impacts of our Project and alternatives rather than siting options. The Department of Commerce's Office of Energy Security ("OES") will prepare an environmental review document called an Environmental Assessment as part of these regulatory proceedings.

There will be several opportunities for the public to comment on the need for the Project, alternatives to meet the need, and potential impacts of the Project. Our applications will be posted on our web site at http://www.xcelenergy.com/Minnesota/Company/Pages/Home.aspx. Any interested party can subscribe to receive notice of any documents filed in the proceeding by registering at:
https://www.edockets.state.mn.us/EFiling/security/login.do?method=show Login

1.2.3 Environmental Permits

In addition to the Certificate of Need, siting and route permitting processes, the Project must also obtain permits from the Minnesota Pollution Control Agency ("MPCA") and the Minnesota Department of Natural Resources ("MnDNR") in regards to water use and air and emissions. A more expansive discussion of other regulatory requirements is presented in Chapter 2 of this application.

1.3 Demand and Supply Need

The Black Dog Repowering Project is needed to address two developing inadequacies or needs on our system:

- *Demand:* Our forecasts predict that the demand for electrical power will continue to grow as population increases and our economy expands. Generation capacity deficits start to show up in 2014 based on a median forecast. By 2016, demand could exceed the ability of the existing system to reliably deliver power by over 470 MW, even after accounting for our aggressive DSM programs.

- *Supply:* Black Dog Units 3 and 4 are among the oldest generating plants on our system. They have served the system well for over 50 years. Our estimate of a shortfall in capacity by 2016 assumes Black Dog Units 3 and 4 will continue to operate. However, our analysis also indicates the investments necessary to extend their life and to meet pending environmental performance standards make it unlikely they can continue to operate as economically as a newer facility. We conclude that our generating system will likely be more efficient and economical if we cease to operate Black Dog Units 3 and 4 and replace the 253 MW of generation with a new facility.

Repowering at the Black Dog Plant with a new, state-of-the-art, natural gas, combined cycle facility is a very advantageous, cost effective way to address the combination of these two needs.

1.3.1 Demand

The Company has service territory in five upper Midwest states and designs, plans and operates an integrated five-state system. As a result, our forecasts address resource and customer needs for our entire service territory of Minnesota, upper Michigan, North Dakota, South Dakota and Wisconsin combined.

We currently project energy growth of 0.9% or approximately 440 GWH per year for the 2011 to 2025 forecast period. During this period, peak demand increases at an average annual growth rate of 1.1% or about 110 MW per year. These estimates incorporate the expected effects of our DSM programs.

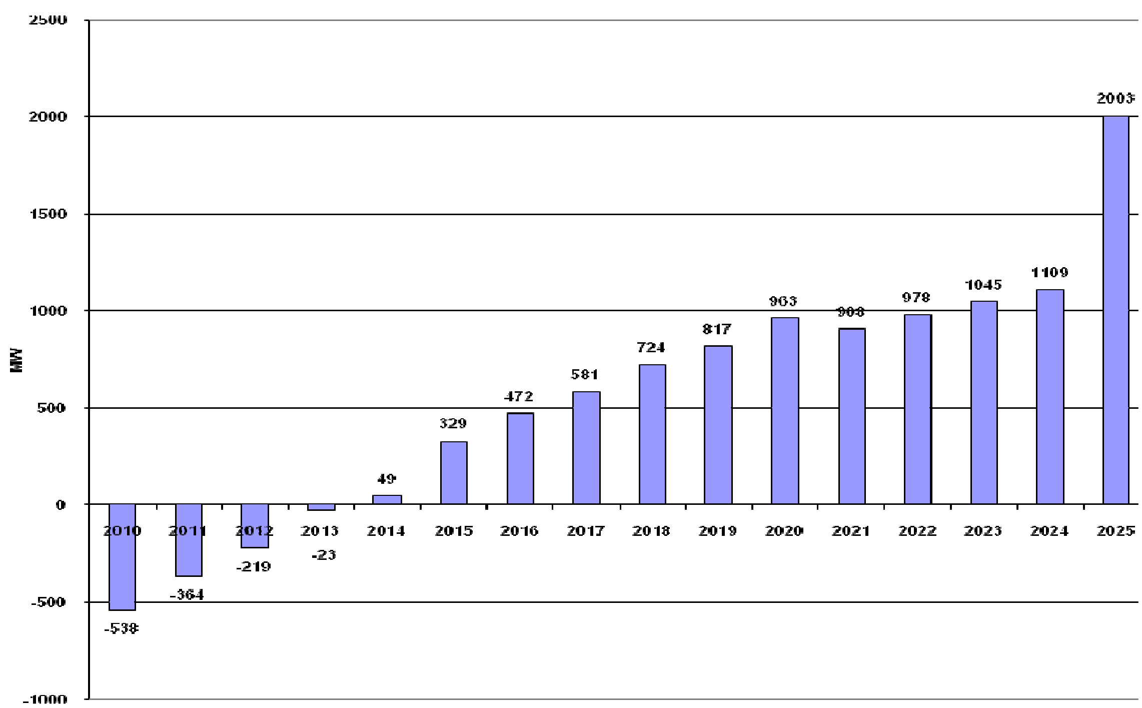
We have worked with the Commission to establish stretch goals for our DSM programs. We are committed to increasing our DSM achievements to 1.5% of sales as presented in our 2010 Resource Plan. Our DSM programs are forecast to reduce peak demands during the summer peak periods by approximately 1060 MW during each year over the planning period. The resource need we have presented in this application assumes we will continue to be successful in these efforts.

Another way in which we can manage resource requirements is by participating in regional reliability groups. By doing so, the total amount of generation necessary to ensure reliability can be minimized. Utilities together with the Midwest ISO have established a 12% reserve margin. Each utility is required to have generation resources 12% higher than peak customer demand. We add the reserve margin into our forecast after accounting for DSM.

Our forecast also includes the assumption that our contracts with Manitoba Hydro do not expire in 2015 and are extended to 2025, providing us with 725

MW of power from 2015-2021 and, potentially, going up to 850 MW in 2021. In addition, the forecast includes 230 MW of capacity increases at our nuclear power plants based on uprate projects that are underway or planned to occur during the next several years. As shown in the figure below, we will need additional generation in the 2015 to 2016 time frame in order to maintain a reliable system.

Figure 1-2: Forecasted Resource Needs by Year



Forecasts are a picture of the future based on what we know today. As a result, we use probability analysis to develop higher and lower forecasts to test the potential impacts of different futures. In Chapter 3 we discuss our forecasts in more detail.

1.3.2 Supply

Our assessment of need assumes Black Dog Units 3 and 4 will continue to be available to generate 253 MW of power throughout the next decade and beyond. However, after examining the condition and performance of the two coal fired units and the investments that will likely be necessary to keep the units operating, we have concluded our power supply may be more cost effective if we cease operating Units 3 and 4 and replace their output as part of our plan to meet growing demand.

Black Dog Units 3 and 4 are over 50 years old. The boilers, turbines and generators are essentially original pieces of equipment that have been well maintained and operated over this entire time period. However, as one would expect from 50-year-old assets, operating data shows declining availability. If the units are to be operated another 20 years, major equipment repairs and/or replacements will likely be required for the turbines, generators, boiler sections, feedwater heaters, pumps and electrical equipment. We estimate over $200 million will likely be needed to refurbish and/or replace aging equipment.

These units will also require substantial upgrades to their pollution control systems to continue to operate. The EPA is in the process of establishing major regulatory changes covering air, water and waste standards. It appears new environmental performance standards may require over $200 million in pollution control upgrades to keep Units 3 and 4 running.

In total, therefore, over $400 million would need to be invested to keep Units 3 and 4 operating on coal at their current capacity ratings. We believe that this capital would be better spent replacing these units with a significantly larger natural gas-fired, combined cycle facility that will also better serve increases in customer demand.

1.4 Analysis of Alternatives

The Black Dog Repowering Project is the most cost effective solution to meet our system need. In Chapter 4 we present the analysis of alternatives that leads us to this conclusion. After evaluating a number of alternatives qualitatively, four different approaches to meeting our system needs were studied quantitatively.

- <u>Life extension</u>: Invest to continue to operate Black Dog Units 3 and 4 and add additional new generation elsewhere on the system to meet growing demand.

- <u>Repower</u>: Cease operating Black Dog Units 3 and 4 and repower at Black Dog with about 700 MW of combined cycle generation.

- <u>Alternative Generation</u>: Cease operating Black Dog Units 3 and 4 and develop additional generation elsewhere on the system to replace it and meet growing demand.

- <u>Renewable Generation</u>: Cease operating Black Dog Units 3 and 4 and develop 700 MW of biomass fueled capacity.

Cost and performance information was developed for each of these alternatives. System cost impacts were simulated using the Strategist resource expansion model. Strategist simulates the operation of our entire generation system over the long term and adds generating resources to meet growing customer needs in the most cost effective way.

We first compared the merits of the alternatives without assigning any externality values for air emissions and without assigning values for the risk of future greenhouse gas ("GHG") regulation. The results indicate that it is in customers' best interests to repower at the Plant. This alternative is superior to developing the needed generation elsewhere. The present value of system capital and operating costs over time from the Strategist model were lowest with the proposed Black Dog Repowering Project. Even if a biomass resource could be developed as modeled, system costs were substantially higher.

We also conducted a number of tests to explore how sensitive the analyses were to the assumptions used. For example, we explored how sensitive the costs of the Project were to a range of possible values associated with GHG regulation. Higher and lower demand forecasts, varying capital cost estimates and fuel price assumptions were also tested. None of the sensitivity testing changed the ranking of the alternatives.

In order to provide further assurance that our Project is the best fit for the need, the Commission has established procedures that provide independent power producers the opportunity to intervene in the Certificate of Need process with competing power purchase proposals. If a competitor's project provides a better fit, that project will be selected over the Company's Project. It will be important then that all the potential costs to customers associated with competing proposals be included in the Commission's decision making.

For example, power purchase alternatives from independent power suppliers may result in significant indirect costs to customers that, if present, will need to be included in any project cost comparisons. Accounting standards require long term power purchase agreements associated with certain types of resources to be treated as capital leases that must be recognized as long term debt. Such accounting treatment will have significant impacts on the Company's capital structure and will increase the financing costs for the Company which in turn will increase customers' costs. Lease accounting treatment results in very real costs to our customers that need to be factored into the analysis. As discussed further in Section 4.3.2, if competing proposals are tendered in this proceeding, it will be important to evaluate the impact of lease accounting standards to make a complete and thorough analysis of alternatives.

1.5 Project Description

The Project's two combustion turbine-generator sets, two heat recovery steam generators ("HRSGs"), and one steam turbine-generator will be located within a new 425 foot by 280 foot by 140 foot tall building in the current coal yard area. Two air inlet filters will be located on the exterior of the structure and five new transformers will be located adjacent to the building. A new 345 kV substation will be constructed next to the generation block. Three water tanks and two ammonia storage tanks will also be added outside the new Plant structure. The exhaust stacks will be approximately 230 feet tall and will be located adjacent to the new structures. Two double circuit 345 kV transmission lines will connect the substation to existing transmission lines passing through the Black Dog plant site on the south side of Black Dog Lake. The new transmission structures will be between 90 and 110 feet tall. A cooling tower will be located where the current ash ponds reside. The cooling tower will be approximately 70 feet tall.

1.5.1 Fuel

The Project will be fueled entirely by natural gas with no backup fuel. We plan to secure firm natural gas supply contracts through a competitive bidding process. Any needed gas pipeline improvements and associated approvals will be the responsibility of the supplier.

1.5.2 Construction Schedule

Generation block construction will begin after approvals are obtained. Site preparation and fill to bring the Project area above the 100 year flood level is anticipated to start in 2012. Shortly thereafter we will discontinue the use of coal at Black Dog Units 3 and 4 and use natural gas. Installation of pilings and construction of foundations will start the following year. Building erection and installation of the large components would occur in 2014. Transmission construction is expected to occur in 2014. In 2015 construction completion and startup of the facility would occur. The combined cycle facility is expected to be in commercial operation by January 2016. We will cease operation of Black Dog Units 3 and 4 once the Project is operating.

1.5.3 Operation

The Project will be integrated into our remote dispatch control center. We expect to use the Project's capability without duct firing (and maximum efficiency point) for intermediate load service, dispatching it after all incrementally more economical and "must run" units have been dispatched. The additional capacity of the Project, available through supplemental firing of the HRSG, will be utilized for peak demand periods.

The Project will also serve to load follow as system load requirements change and compensate for intermittent or variable non dispatchable generation such as wind power. The Project will be able to commence start up after a 30-minute notice and will have the ability to ramp at approximately 5 to 10 MW per minute depending on the pre-existing steam turbine condition.

The Project is expected to be dispatched 5 days per week, 16 hours per day with an initial annual capacity factor of 35%. It is expected that the capacity factor will rise to higher levels as system demands increase.

1.5.4 Cost

We estimate the capital cost of the facility will be approximately $600 million. More detailed cost information has been designated as trade secret since it could be used by independent power producers to design competing power purchase proposals. Access to capital and operating cost information could conceivably result in proposals at higher rates than might otherwise be offered. Capital costs include the repowered plant costs, substation costs, interconnecting transmission line costs and the incremental costs of a cooling tower attributable to the Project. In our examination of alternatives in Chapter 4 we also describe some of the contingencies that may affect the cost of the facility.

Our cost estimates are based on the Project schedule summarized above. Delays could significantly affect the actual costs. We look forward to working with the Commission and OES staffs and interested parties to achieve the permitting milestones necessary to keep the Project on schedule.

1.6 Environmental Performance

Chapter 6 of this application provides a discussion of the environmental performance of our Project. The Black Dog Repowering Project has been designed to meet all the requirements necessary to obtain air and water permits. As the result of the Black Dog Repowering Project, emissions will be reduced in a major metropolitan area and the overall environmental performance of our system will be improved.

1.6.1 Air

Natural gas-fired combined cycle technology is among the most efficient and cleanest means of generating fossil fired utility-scale electricity. Natural gas combustion generates significantly less CO_2, particulate matter, SO_2, and toxic air emissions (including Hg) than oil or coal.

The primary constituents of concern resulting from combustion of natural gas are NO_x, carbon monoxide ("CO") and volatile organic compounds ("VOCs"). The Project will control NO_x emissions through use of dry low-NO_x burners and selective catalytic reduction systems ("SCR"). Good combustion practices and oxidation catalysts will be used to control emissions of fine particulates, CO, and VOCs.

Preliminary estimates are that NO_x, SO_2, and Hg emissions will be reduced 96 to 99% on an annual basis, and that particulate matter and carbon dioxide emissions will be reduced 50 to 65% on an annual basis as compared to current operations. The Project will result in reduced GHG emissions and contribute to our ability to implement the GHG emission reduction goals envisioned by Minnesota Statutes Section Chapter 216H.

1.6.2 Water

Water usage associated with operation of the Project will be similar to that of the existing Plant and will not have a major impact on water supplies or water quality after discharges. Surface water appropriated from the Minnesota River is currently used for cooling water and will be used to supply the cooling water for the Project as well. The total surface water appropriations for the site will be within the existing Water Appropriations Permit (#1961-0270) limitations. For once-through cooling, the withdrawal rate will be higher than recent years but similar to operations of the Plant in the late 1990's. A closed cycle operating mode with a cooling tower would result in significantly lower withdrawal volumes.

Groundwater from the existing well will supply other water needs for the Project. No increase in the groundwater appropriation rate or annual withdrawal volume will be required for the Project.

1.6.3 Noise

Noise from the generating units is not expected to have a significant impact. The generating units will be in compliance with state noise standards. The generation is located in an isolated area with the nearest residences located more than 1,500 feet away from the Plant. Noise from the operation of the Project is expected to be predominantly low frequency noise, as is noise from traffic. Noise from the generation operations will not significantly impact the acoustical environment given the noise control technology that will be employed by the new generating units. In addition, we will cease operating the existing Units 3 and 4 along with the noise associated with coal trains and other coal and ash handling processes.

1.6.4 Land Use

The Black Dog Repowering Project takes advantage of an existing site and does not create new land use impacts. The Plant is located on a 35 acre parcel which is well buffered within an approximately 1900 acre area owned by the Company. The transmission necessary to connect the Project to the transmission grid will be built on Company property and will not require easements from private landowners.

1.7 Certificate of Need Criteria

The criteria the Commission will use to evaluate our Certificate of Need request are contained in Minnesota Statutes Section 216B.243 and in Minnesota Rules Chapters 7849 and 7829. A Certificate of Need must be granted to an applicant upon determining that four principle criteria of Minnesota Rule 7849.0120 are met. They are:

A. The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states…,

The demand for electricity on our system continues to grow. Without this additional generation we anticipate inadequate generating resources to reliably and efficiently meet our obligation to serve. The Project provides about 450

MW of incremental capacity in a time frame when our forecasts show a capacity deficit.

> B. *A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record…,*

Our analysis of alternatives demonstrates that the most cost effective way to meet our resource needs is to cease operating Black Dog Units 3 and 4 and repower at the Plant site with about 700 MW of natural gas combined cycle generation. Furthermore the addition of generation at a site within the metropolitan load center provides important system benefits. The opportunity for competing proposals as part of the Certificate of Need process will help ensure the Commission's decision will be in customers' best interests.

> C. *By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health…,*

The Black Dog Repowering Project is the most cost effective solution to maintain reliable service to our customers. It provides significant socioeconomic benefits by helping to keep the cost of energy as low as reasonably possible. The Project takes advantage of an existing site to minimize impacts to the natural and man made environment. Repowering at the Black Dog Plant site at the same time we cease operation of Units 3 and 4 provides a unique opportunity that may not be available in the future.

> D. *The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.*

The Black Dog Repowering Project will be designed to meet all water use, air quality and water quality standards necessary to obtain operating permits. The Project will result in continued improvement in the overall environmental performance of our generating fleet and help us continue to make progress toward the environmental policy goals of the state.

We believe our Project best satisfies these four criteria and respectfully request the Commission grant our request for a Certificate of Need.

2 General Information and Regulatory Permits

2.1 Applicant Information

The applicant's complete name and address, telephone number, and North American Industry Classification System ("NAICS") and Standard Industrial Classification ("SIC") codes are:

Northern States Power Company, a Minnesota corporation ("Xcel Energy")
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500
NAICS: 221119
SIC: 4911, 4922

The official or agent to be contacted regarding the filing is:

Sara J. Cardwell
Manager, Regulatory Administration
Xcel Energy
414 Nicollet Mall, GO 7
Minneapolis, MN 55401
(612) 330-7975

2.2 Description of Business and Service Area

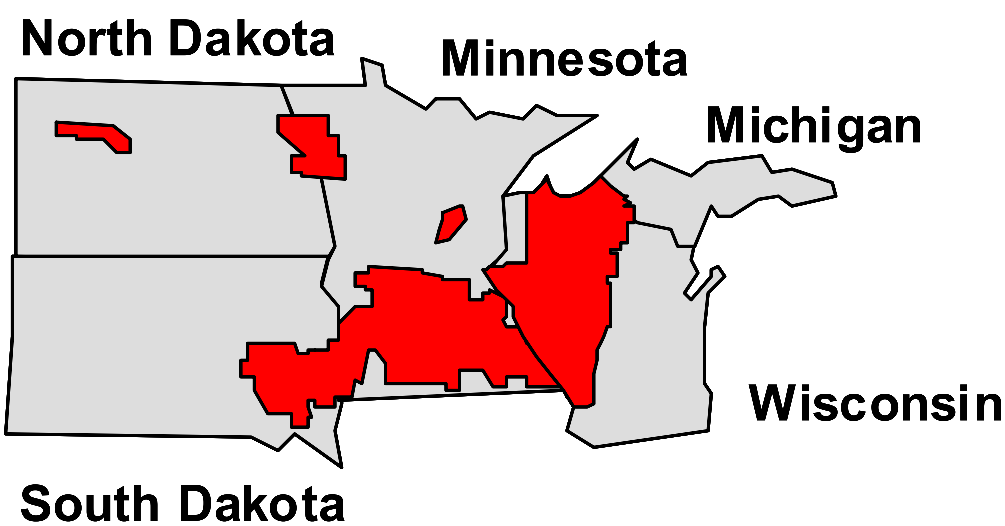
Northern States Power Company is a public utility under the laws of the state of Minnesota. The legal name of Xcel Energy is Northern States Power Company ("NSP"), a Minnesota corporation. NSP and its parent public utility holding company, Xcel Energy, are headquartered in Minneapolis, Minnesota.

Xcel Energy is a public utility that generates electrical power, and transmits, distributes, and sells it to residential and business customers on an integrated system basis within service territories assigned by state regulators in parts of Minnesota, South Dakota, and North Dakota, with our affiliate utility serving portions of Wisconsin and the upper peninsula of Michigan. The Company owns and operates a number of electric generation facilities serving this area using a variety of technologies and fuels including, wind, coal, oil, natural gas, hydro, refuse derived fuel ("RDF") and nuclear. Additional wind, landfill gas, biomass and additional hydropower are also included in our generation portfolio through purchased power agreements ("PPAs").

Xcel Energy's integrated system has 1.5 million electricity customers in the upper Midwest. Figure 2-1 shows the Company's upper Midwest service territories in the states of Minnesota, Wisconsin, Michigan, North Dakota and South Dakota.

The Black Dog Generating Plant is owned and operated by Northern States Power Company.

Figure 2-1: Xcel Energy Upper Midwest Service Territory



2.3 Certificate of Need Process and Competitive Acquisition

The Commission indicated in the Company's 2004 and 2007 Resource Plan dockets that the Company should rely on competitive processes as much as possible to meet resource requirements. Thus, the Company has conducted a number of competitive bidding processes to acquire new resources. Competitive bidding involves issuing formal Requests for Proposals, reviewing proposals received from developers, selecting the most cost effective projects, negotiating purchase agreements and requesting the Commission's review and approval of the purchase agreements. However when an opportunity to rehabilitate an existing Company-owned site such as that provided by the Black Dog Repowering Project presents itself, the competitive bidding process does not work well.

In the 2004 Resource Plan Docket, parties developed and the Commission approved an alternative process that takes some of the elements of competitive bidding and applies them when the Company proposes new generation.

This alternative process, which is referred to as the "Track Two" process, ensures that independent developers have the opportunity to offer competing generation proposals as part of a Certificate of Need proceeding. Developers that want the Commission to consider a competing proposal must intervene in the Certificate of Need proceeding. After the developer provides the information necessary to evaluate their alternative, the Commission refers the matter to the Office of Administrative Hearings for a contested case proceeding.

The purpose of a contested case proceeding is to develop a record that establishes need and evaluates and compares the merits of the alternatives. An Administrative Law Judge presides over the hearing and makes a recommendation. The Commission then makes its decision to grant the Company a Certificate of Need, which in this case would authorize the Black Dog Repowering Project or to direct the Company to negotiate a power purchase agreement with the successful competing developer.

The main steps of the Track Two process are summarized below:

A) The Company initiates the process with a Certificate of Need filing that identifies the size, type and timing of the resource need and seeks approval for the selected resource to fill this need. The filing contains the information necessary to evaluate the proposal and sufficient information to allow prospective competitors to make alternative proposals.

B) The Commission establishes a procedural schedule to provide adequate time for alternative proposals to be prepared. The Commission also approves a plan to provide notice that will encourage the submittal of alternative proposals.

C) The Company provides additional notice as directed by the Commission to facilitate the submittal of alternative proposals. Notice provides prospective competing developers the information and direction needed to provide complete alternative submissions to the Commission and the Company.

D) If competing proposals are submitted, a contested case hearing process is conducted before an independent Administrative Law Judge. The record of the proceeding, including findings and recommendations, becomes the basis for a selection decision by the Commission. To the extent that no competing proposals are submitted, the process would continue as a regular Certificate of Need proceeding, using the alternatives provided by the Company to evaluate the reasonableness of the Project.

E) If the Commission selects the Company's proposal, the Commission Order provides the requested approval.

F) If the Commission determines that one of the competitive alternatives is a better option, the Company is given a four-month period to negotiate a PPA. Following the negotiation period, the Company would file for approval of the PPA. If the parties are unable to reach an agreement, the Company must file an explanation and proposed next steps with the Commission.

G) For an approved PPA, the project would proceed to obtain any remaining permits, but a certificate of need would not be required per Minnesota Statutes Section 216B.2422, subdivision 5.

H) Upon receipt of all needed permits, the project proceeds to implementation.

2.4 Notices, Procedural Guidance and Schedule

Appendix D provides the guidance we propose to provide to prospective competitors for use in developing a proposal to submit to the Commission and the Company for consideration in this proceeding. As part of this guidance, we propose that intervening developers contact the OES with their questions. The OES provides an independent source to answer questions thereby ensuring effective communication, process transparency, and the even-handed application of requirements.

We have structured our guidance to provide flexibility to developers. Capacity amounts that differ materially from the Company's Project will be evaluated accordingly. We issued a press release commensurate with this filing on March 15, 2011 announcing the Black Dog Repowering Project.

Once the Commission establishes a deadline, we have proposed June 1, 2011, for competing submissions, we propose to distribute the supplemental notice outlined in Appendix D. The proposed supplemental notice informs potential developers that the Company has initiated the proceeding. The supplemental notice further explains the framework that will be used, the information required, and the deadline for proposals to be submitted to the Commission. Below is the list of media outlets we propose to use in our notification process.

Table 2-1: Publications List

Print News Media	**TV and Radio Media**
Megawatt Daily	Associated Press – Minneapolis
St. Paul Pioneer Press	KARE – TV
Minneapolis Star Tribune	KMSP – TV
Twin Cities Business Journal	KSTP – TV
Minnesota News Network	WCCO – TV
Dow Jones Newswires	WCCO – Radio
Platts Electric Power Newsletters	Minnesota Public Radio
Hydro Review Magazine	**Web Sites**
	Xcel Energy Web
	Dept. Of Commerce E-Dockets

2.5 Related Filings and Permits

In addition to a Certificate of Need, the Black Dog Repowering Project will require several other permits and approvals from the Commission, other state agencies and other authorities.

2.5.1 Site and Route Permits

Pursuant to Minnesota Statutes Chapter 216E, the Project meets the definition of a large electric power generating plant ("LEPGP") and requires a Site Permit. The section of 345 kV transmission required to connect the new units to the transmission system meets the definition of a HVTL and requires a Route Permit.

We plan to file the combined site and route permit application by early May 2011. There will be additional opportunities for the public to comment on the potential impacts of the Project as the OES will conduct one or more public hearings.

2.5.2 Gas Pipeline Routing Permit

The Company will issue an RFP for natural gas transportation. The selected provider will apply for a routing permit if needed in accordance with the requirements of Minnesota Statutes Section 216G.02 and Minnesota Rules Chapter 7852 as well as any other necessary permits for the gas pipeline construction and operation, such as the general National Pollutant Discharge Elimination System ("NPDES") Stormwater Permit for Construction Activity, if required by the pipeline project's estimated area of disturbance.

2.5.3 Transmission System Filings

Generator Interconnection Agreement

On September 10, 2010, Xcel Energy filed the required Generation Interconnection Agreement Request with the Midwest ISO to cover an expected capacity increase of up to 500 MW at the Black Dog Plant site. The Midwest ISO evaluates interconnection requests to determine if additional transmission system improvements will be needed to maintain reliable operation of the system. The study results could indicate additional transmission upgrades for interconnecting the Project are needed.

Transmission Service Request

On February 10, 2011, the Midwest ISO confirmed that the Company would receive firm transmission service to cover an expected capacity increase of up to 500 MW at the Black Dog Plant site, conditional on the completion of two previously planned Midwest ISO MTEP projects.

2.5.4 Environmental Permits

Air Emission Permit

We expect to file an application with the MPCA in spring 2011 for an amendment to the Plant's air emission permit, Permit No. 03700003-009, to accommodate the Project.

NPDES Discharge Permit

We will apply for an amendment to the Plant's existing NPDES discharge permit in late 2011 to modify the Plant's discharges. Modifications will entail the cooling water system and its discharges and the process water system and its discharges. The modifications will address the Project, the future operation of existing Unit 5/2[1] as well as ceasing operation of the existing Unit 3 and 4 components. In addition, an application will be filed with the Metropolitan Council Environmental Services ("MCES") for approval to direct some plant wastewater streams to sanitary sewer. Addition of an outfall structure to discharge to Black Dog Lake may also require obtaining a U.S. Army Corps of Engineers Section 10 Work in Navigable Waters and Section 404 Dredge and Fill Permit and/or a MnDNR Work in Protected Waters Permit.

NPDES Stormwater Program

The Project triggers the requirement to apply for coverage under the MPCA's NPDES Stormwater Permit Program for Construction Activities. We will prepare a Stormwater Pollution Prevention Plan ("SWPPP") and apply for coverage under a general permit prior to commencement of Project construction activities. We will require contractors to comply with the SWPPP and the stormwater permit.

For existing operations, the Plant maintains an Industrial Activity SWPPP as required by the Plant's NPDES permit. Prior to the Project's commercial operation, Xcel Energy will update the Industrial Activity SWPPP as necessary.

Section 404 Wetland Permit

Depending on extent of work in waters, some construction activities or components may require obtaining a U.S. Army Corps of Engineers Section

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[1] In 2002, the original Unit 1 boiler/turbine and the Unit 2 boiler at the Black Dog facility were repowered with a natural gas-fired, combined cycle unit (Unit 5/2). Exhaust heat from Unit 5 powers the Unit 2 steam turbine.

404 Dredge and Fill Permit and/or a MnDNR Work in Protected Waters Permit.

2.5.5 Other Permits, Approvals or Notifications

The Project may also require permits, approvals or notifications under the following programs:

- Federal Aviation Administration Notice of Proposed Construction or Alteration (for exhaust stack and potentially other structures)
- MnDNR Crossing Permits for Associated Utilities (e.g. electric transmission lines, natural gas lines, sewer lines) by Xcel Energy or by the provider
- Floodplain Work Approval through Site Permitting
- Exemption to allow burning of natural gas for power production (DOE, 10 CFR 503)
- Road Crossing Permits (Mn/DOT, Minn. R. Chapter 8810)
- Endangered Species Act Review
- Miscellaneous State Building and Construction Permits and Inspections (Minn. Stat. § 216E.10, Subd. 2)

We also plan to work closely with local governments and other officials to address any reasonable concerns they might have as we move forward with the Project in our Site and Route Permit processes.

3 Demand and Supply Need

The Commission must determine that four principal criteria are met when granting a Certificate of Need (Minn. R. 7849.0120). This Chapter addresses the first criterion (Subpart A) that:

"the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states."

The Black Dog Repowering Project, or a suitable alternative, is needed to address two developing inadequacies or needs on our system:

- *Demand:* Our forecasts predict that customers' demands will continue to grow. Generation capacity deficits start to show up in 2014 based on a median forecast. By 2016, demand could exceed the ability of the existing system to reliably deliver power by approximately 470 MW after accounting for our DSM programs.

- *Supply:* Black Dog Units 3 and 4 are among the oldest generating units on our system. They have served the system well for over 50 years. Our estimate of a shortfall in capacity by 2016 assumes Black Dog Units 3 and 4 will continue to operate. However, our analysis indicates the investments necessary to extend their life and to meet evolving environmental performance standards make it unlikely they can continue to operate as economically as a newer facility. We conclude our generating system can be made more efficient and economical if the 253 MW of generation from the existing Black Dog Units 3 and 4 is supplied by a new facility that also fulfills the need for additional capacity.

3.1 Demand and Energy Forecasts

The Company designs, plans and operates a five-state integrated system. As a result, our forecasts address resource and customer needs for our combined service territories in Minnesota, Michigan, North Dakota, South Dakota and Wisconsin. We forecast the number of customers and energy sales by customer class for each of the five state jurisdictions separately and then aggregate them. Serving our customers in this five state area on an aggregated basis reduces overall system costs and increases system reliability.

The use of a five-state system forecast is appropriate and consistent with the methodology used in our resource planning and all other generation related Certificate of Need applications we have filed. Therefore, the growth of our system depicted in this chapter is the five-state system forecast.[2]

Our forecast of peak demand in our five-state upper Midwest system is shown below in Figure 3-1. Figure 3-2 below illustrates our forecast of energy consumption. The methodology used to develop the forecast demand and other forecast details required by Minnesota Rule 7849.0270 are provided in Appendix A. The forecast in Figures 3-1 and 3-2 incorporates the DSM savings goal approved in our 2010-2012 Triennial Conservation Improvement Plan ("CIP").

We project energy growth of 0.9% or 444 GWh per year for the 2011 to 2025 forecast period. During this period, the median base peak increases at an average annual growth rate of 1.1% or approximately 110 MW per year.

[2] Minn. R. 7849.0270, subp. 2 (A) and subp.. 3 and Minn. R. 7849.0270 subp. 3(D) require the submittal of the statistical tests for the forecast used. Since Xcel Energy forecasts peak demand and energy for the five-state system by customer class for each state jurisdiction, the data is voluminous (>1,000 pages). Therefore, we have not included the information required by Minn. R. 7849.0270 subp. 3(D) with this application, but will provide it on CD upon receiving an information request from the OES or any other parties to this proceeding.

Figure 3-1: Median Base Summer Peak Demand (MW)
NSP System with 1.15% Retail Sales DSM Adjustment

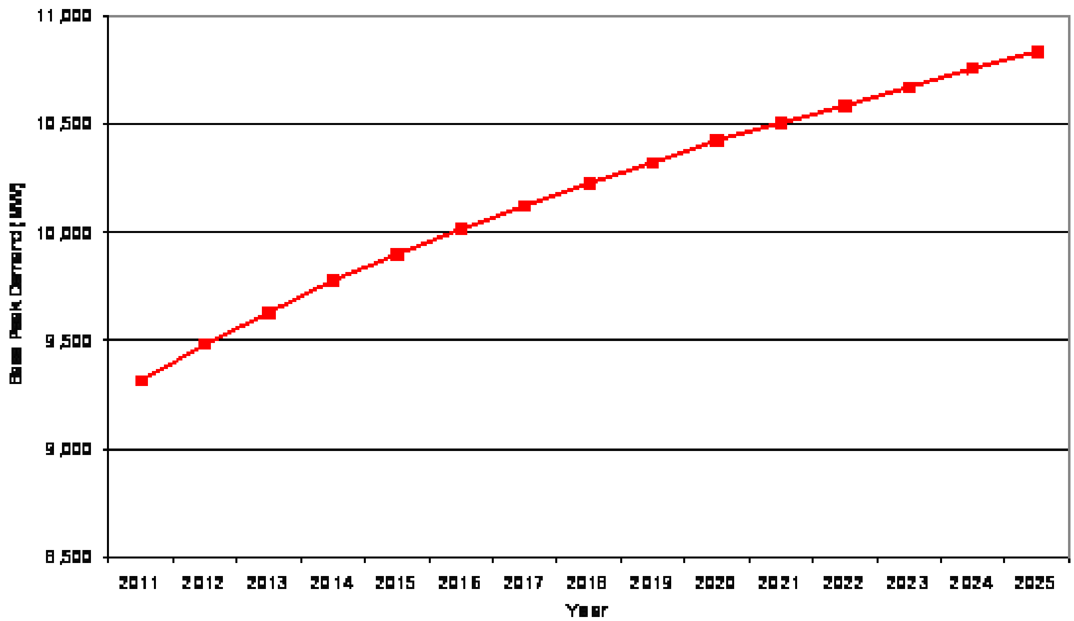
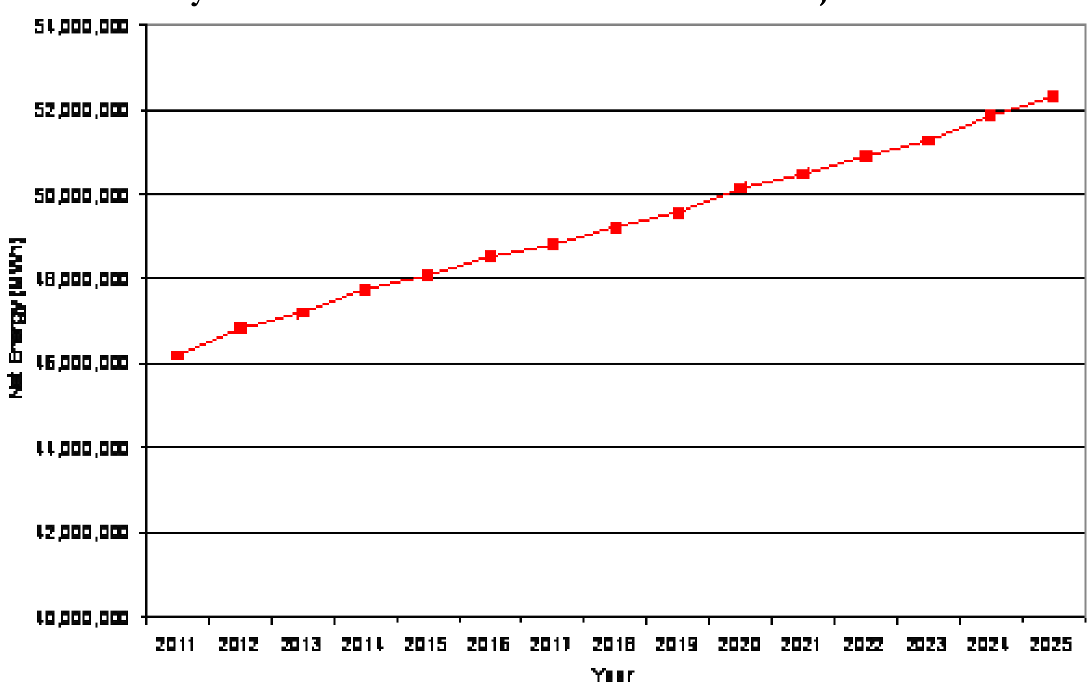


Figure 3-2: Median Net Energy (MWh)
NSP System with 1.15% Retail Sales DSM Adjustment



3.1.1 Forecasts Incorporate DSM

Our forecasted demand is not growing as a result of promotional activities to sell electricity. We do not have programs promoting the sale of electricity – we have programs that promote the conservation of electricity. Our forecast incorporates the peak demand and energy savings goals estimated in our most recent CIP Triennial Plan. Our resource need analysis in our 2010 Resource Plan assumes we achieve a 1.15% reduction in sales from DSM programs in 2010, 1.2% in 2011, and 1.3% in 2012 and thereafter. As we discuss in our 2010 Resource Plan, we propose to fully implement our 1.3% savings goal and work toward meeting the state goal of 1.5% in DSM savings over the next several years. And, in fact, our preliminary results for 2010 indicate we may achieve a 1.3% savings, or over 400 GWhs for the year.

In order to meet our DSM goals, we devote significant resources to our DSM programs. Between 1990 and 2009, Xcel Energy spent over $754 million (nominal) on Minnesota DSM efforts and saved over 5,027 GWh of energy and 2,442 MW of demand.

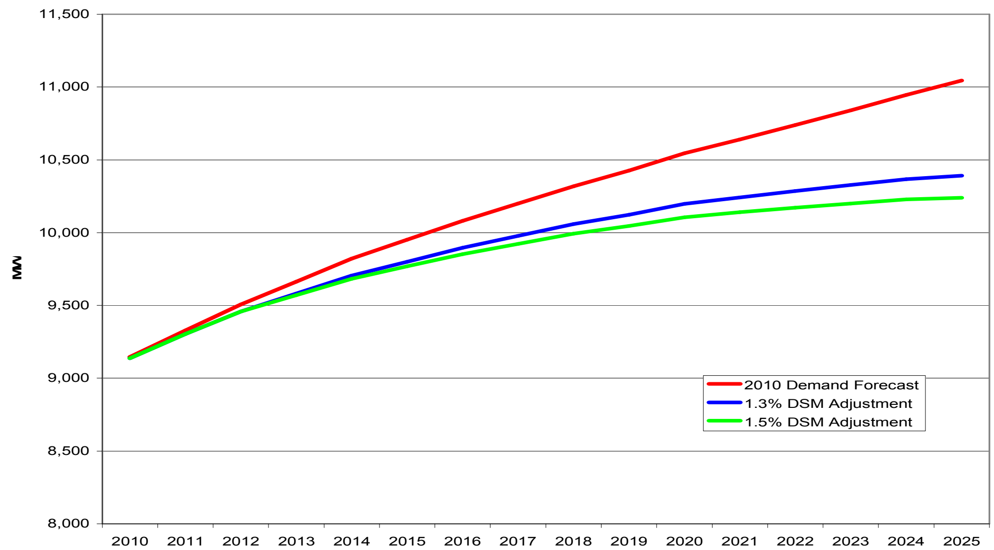
Table 3-1: DSM Goals Approved in 2010-12 CIP Triennial Plan

	2010	2011	2012	Total
Budget	$ 75,935,992	$ 81,002,168	$ 86,183,239	$243,121,399
Energy Savings (MWh)	349,653	367,263	399,220	1,116,136

Additional detail on our DSM programs is presented in Appendix C.

Figure 3-3 below illustrates the further reductions in demand we estimate can be achieved over time if we are able to sustain DSM savings of 1.3% and 1.5% of retail sales.

Figure 3-3: NSP Median Base Summer Peak Forecast Adjusted for 1.3% and 1.5% DSM Savings



While we are committed to working with stakeholders to expand our DSM programs to achieve the 1.5% level there remains considerable uncertainty in how to achieve these results, how quickly results can be achieved and how sustainable results will be. For planning purposes we have reduced our demand forecast to reflect the 1.3 % DSM savings level. The 1.5% level of DSM would not materially change our resource need in this case since it would reduce generation capacity requirements by only about 40 MW in the 2016 timeframe.

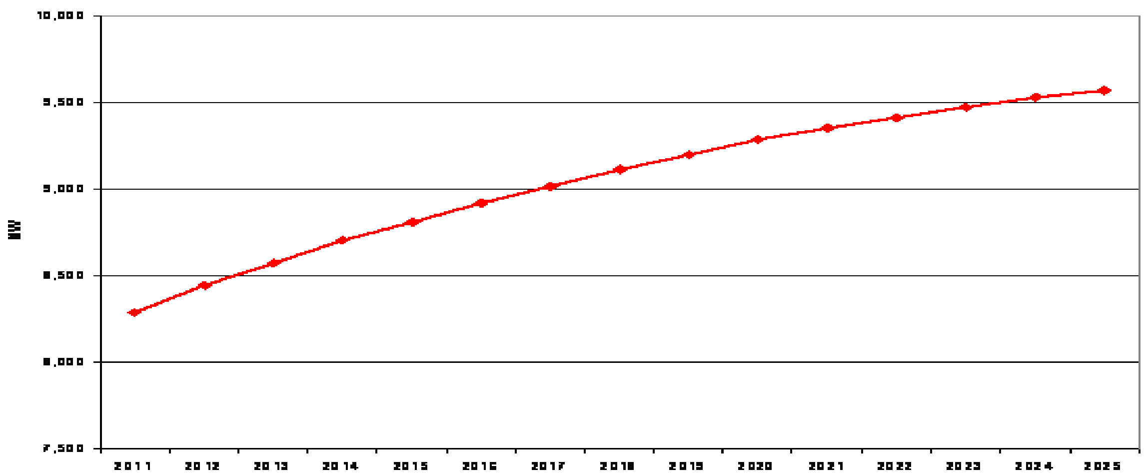
Our peak demand forecast includes the effects of our load management programs that have the ability to reduce peak demand by approximately 1060 MW during each year of the planning period. The need for additional resources is based on the forecast that includes the estimated effects of all DSM programs.

3.1.2 Reserve Requirements

The Midwest ISO establishes the Resource Adequacy Margin that each of its load-serving entities like Xcel Energy must plan for on their system to ensure adequate capacity in the region. Currently, that Reserve Adequacy Margin is 11.94% of system peak capacity. Thus, we must plan for and procure generation to meet an additional 11.94% of our system peak demand to comply with our Midwest ISO reserve requirements. Reserve margins are reevaluated by the Midwest ISO annually. The resource need analysis described in this application uses a Reserve Adequacy Margin of 12% for the planning period.

Figure 3-4 below illustrates our peak demand forecast that includes a 1.3% DSM adjustment and 12% reserve margins. We use this adjusted forecast to assess generation resource requirements.

Figure 3-4: Medium Net Summer Peak Demand with 1.3% DSM Adjustment



3.2 Generation Requirements

We meet our customers' needs for electricity with a combination of Company-owned-and-operated generating facilities, and long- and short-term power purchases. Our most recent forecast of load requirements and available resources is illustrated below in Figure 3-5. This forecast assumes that our contracts for 850 MW of power from Manitoba Hydro are extended to 2025. Our generation resource analysis also includes 230 MW of base load capacity increases at our nuclear power plants that are underway or planned to occur during the next several years.

Figure 3-5: Requirements and Resources 2011-2024

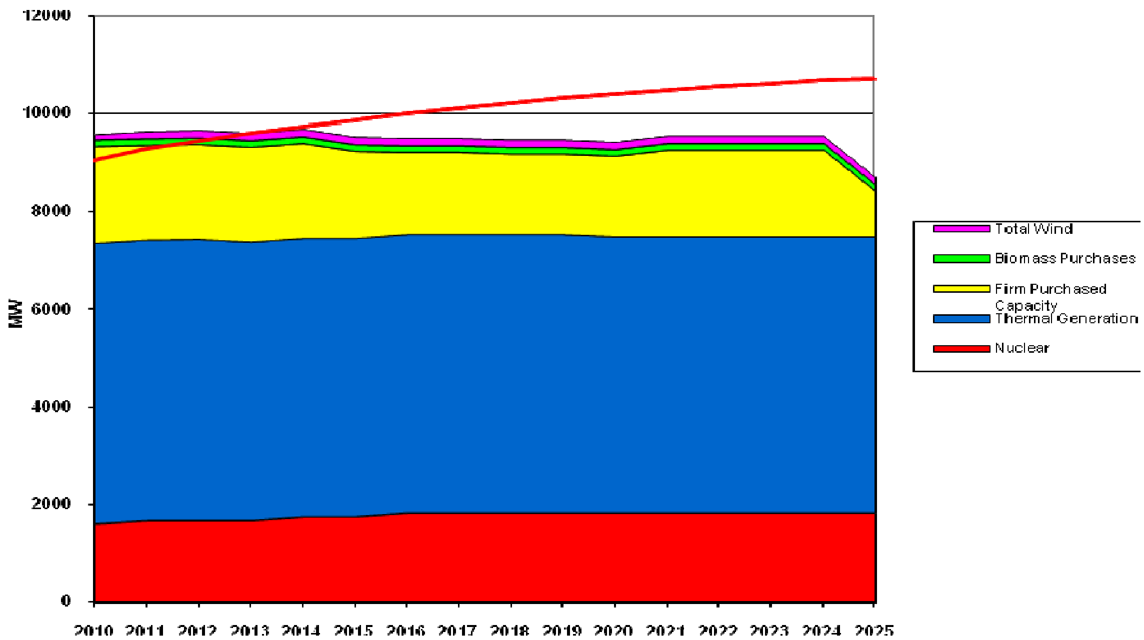
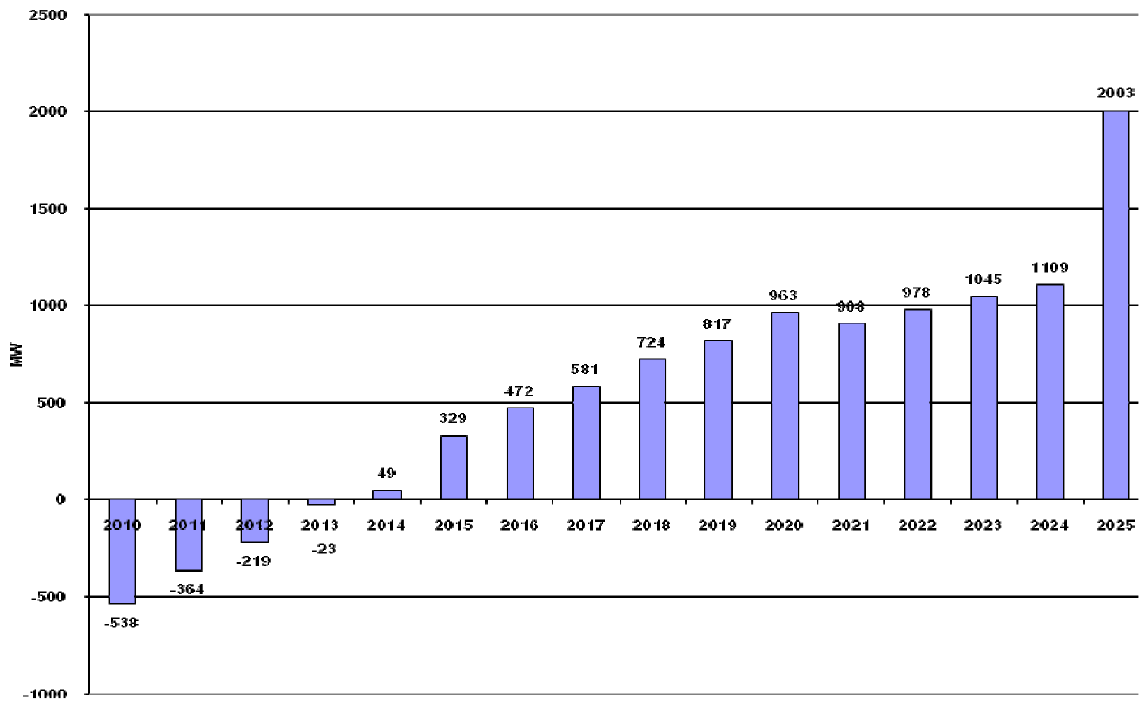


Figure 3-5 above shows that based on our forecast of customer needs, adjusted for aggressive DSM programs and Midwest ISO Resource Adequacy Requirements, we will face a significant resource capacity deficit beginning in 2015.

Figure 3-6 below shows our projected resource needs in more detail.

Figure 3-6: Forecasted Resource Needs by Year



3.3 Supply: Black Dog Units 3 and 4

Our resource assessment in Figure 3-6 assumes Black Dog Units 3 and 4 will continue to be available to generate 253 MW for another 20 years. After examining the condition and performance of the two coal fired units and the investments that will likely be necessary to keep the units operating, we have concluded our power supply will be more cost effective if we cease operating Units 3 and 4 and replace their output.

Black Dog Units 3 and 4 were put into service in 1955 and 1960. They use low sulfur, sub-bituminous coal to fuel Babcock and Wilson pulverized coal-fired boilers. Particulate matter is captured using electrostatic precipitators. The boilers, turbines and generators are essentially original equipment which has been well maintained and operated over their entire lives. However, as one would expect from 50-year-old assets, operating data shows declining availability. In order for the units to continue to operate, they will require significant investment due to aging components and systems.

If the units are to be operated another 20 years, major equipment repairs or replacements will likely be required for the turbines, generators, boiler sections, feedwater heaters, pumps and electrical equipment. The equipment would not need to be replaced all at the same time unless it became prudent to include the work as part of a larger project for cost or regulatory reasons. An investment of over $200 million in today's dollars would likely be needed over time to refurbish and/or replace aging equipment.

There are other potential risks in extending the coal-fired operation of Units 3 and 4. Many similar sized units were built during the same time period as Units 3 and 4. However, utility boilers constructed prior to Units 3 and 4 were smaller in size and most have been retired from service. This makes estimating the remaining life of high temperature and pressure components, such as steam drums, difficult due to the limited industry data and experience with similar units.

The second area of major capital investments facing Black Dog Units 3 and 4 is in the area of pollution control. The EPA is in the process of implementing major regulatory changes in air, water and waste standards. It appears these new environmental performance standards could require over $200 million in pollution control upgrades to continue to operate Black Dog Units 3 and 4.

Maintaining the status quo will not be allowed based on what we know of the expected environmental regulations summarized below.

3.3.1 Ozone NAAQS

On January 19, 2010, EPA published proposed revisions to the ozone National Ambient Air Quality Standard ("NAAQS") in the *Federal Register*. EPA's current plan is to finalize these standards in July 2011. The impact of this change depends on the numerical standard selected by EPA. The MPCA has publicly presented information on how the value selected will impact NAAQS compliance status in Minnesota and what that means to both industrial and mobile sources of NO_x emissions. Until the rule is finalized, we will not know which facilities will need what types of controls. However, the continued long-term operation of Black Dog Units 3 and 4 on coal would likely trigger a requirement for NO_x controls on theses units, including installation of a selective catalytic reduction system.

3.3.2 CAIR Caps/Proposed CAIR Replacement Rule

On August 2, 2010, the Clean Air Transport Rule ("CATR" or "Transport Rule") was proposed to replace the court-vacated Clean Air Interstate Rule ("CAIR"). Aimed primarily at the control of regional emissions to address acid rain, ground-level ozone and particulate matter precursors, the Transport Rule would set limits for states included in the rule at levels deemed necessary for the protection of downwind states' air quality. It also could allow for flexible compliance mechanisms, such as a limited form of emissions trading, similar in form to the Acid Rain Program established 20 years ago. CATR is expected to be finalized by mid-2011. Implementation dates for facilities in Minnesota would be 2012 for NO_x and 2014 for SO_2. The form and content of the final rule will dictate how this rule impacts each facility. Until the rule is finalized, we will not know which facilities will need what types of controls. However, we anticipate that Black Dog Units 3 and 4 as currently configured, would need to install NO_x and SO_2 controls, probably in the form of flue gas scrubber and bag house particulate filters, in order to comply with the rule.

3.3.3 Proposed Rule for CCBs Management

On June 21, 2010, EPA proposed rules regulating coal combustion residuals ("CCR"). The public comment period for this proposed rule ended on November 19, 2010, and EPA received a number of substantive comments concerning the various alternatives being considered. The content and timing of the final rule, which at this time remains highly uncertain, will dictate how this rule impacts Black Dog Units 3 and 4. Under one possible scenario, EPA could designate CCR's to be a "Special Waste" under the Resource Conservation and Recovery Act ("RCRA") Subtitle C, which would impose costly additional regulatory requirements for CCR handling, storage and disposal operations which might result in the need for significant upgrades to the bottom of settling ponds at the plant site.

3.3.4 CO_2 Regulation

The EPA finalized several rules regulating CO_2 in 2010. However those rules have been the subject of court challenges and Congress continues to debate the appropriateness of the Administration's approach. Due to changes in the political make-up of Congress, the possibility of further climate legislation seems less likely in the next couple of years. While legislative action is not likely to happen soon, EPA is continuing to act to regulate CO_2 from electric utility generating units. These regulatory changes will directly impact Black Dog Units 3 and 4 if major modifications are needed to continue coal operations. If a major modification were made, we would need to conduct a Best Available Control Technology ("BACT") review for CO_2 and other GHGs and implement BACT in order to make the modification. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing CO_2 emissions.

3.3.5 Hazardous Air Pollutants MACT Rule

EPA has been tasked with developing National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Electric Utility Steam Generating Units ("EUSGUs"), commonly referred to as the Utility Maximum Achievable Control Technology ("MACT") rule. Under this rule EPA will be regulating a number of hazardous air pollutants ("HAPs"), including: mercury, non-mercury metallics, acid gases, dioxin/furan organics, and non-dioxin/furan organics. EPA is under a consent decree as a result of a lawsuit to issue the new standards by no later than November 2011. We anticipate that the NESHAP will require affected facilities to demonstrate compliance within 36 months thereafter. Until the rule is proposed and finalized in 2011, we do not know which facilities will need what types of controls. However, it is likely that additional controls for mercury, non-mercury metallics, acid gases, dioxin/furan organics, and non-dioxin/furan organics will need to be installed on Black Dog Units 3 and 4 as currently configured. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing HAP emissions.

3.3.6 SO_2/NO_2 Primary NAAQS

On February 9, 2010, EPA finalized rules tightening the primary NAAQS for nitrogen dioxide ("NO_2"). The new standard is a one–hour standard at a level of 100 parts per billion that replaces the existing annual primary NO_2 standard. The new standard has the potential to force additional expenditures for Black Dog Units 3 and 4 to reduce emissions of NO_2.

On June 22, 2010, EPA finalized rules tightening the primary NAAQS for SO_2. The new standard is a one–hour standard at a level of 75 parts per billion that replaces both the existing 24-hour and annual primary SO_2 standards. The new standard has the potential to require additional expenditures for Black Dog Units 3 and 4 to reduce emissions of SO_2.

It should be noted that this rule will impact the Black Dog site regardless of whether the Project proceeds. The Repowered Plant would minimize NO_x emissions with control technology in order to address the NO_2 NAAQS. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing SO_2 emissions.

3.3.7 SO_2/NO_2 Secondary NAAQS

EPA plans to issue a proposed rule revising the secondary NAAQS for NO_2 and SO_2 by July 2011 and a final rule by March 2012. Until EPA proposes and finalizes the rules we cannot know what will be required of the Plant to comply with the rules.

It should be noted that this rule will impact the Black Dog site regardless of whether the Project proceeds. The Repowered Plant would minimize NO_x emissions with control technology in order to address the NO_2 secondary NAAQS. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing SO_2 emissions.

3.3.8 Clean Water Act 316(b) Cooling Water Intake Rule

EPA continues to develop national regulations governing the design, maintenance and operation of cooling water intake structures pursuant to Clean Water Act Section 316(b). We expect EPA to propose these rules before the end of March 2011. The draft rules are currently with the Office of Management and Budget for interagency review prior to publication. We do not know the contents of these new rules but expect that the existing Plant will be impacted by the regulations when they are promulgated. The Repowered Plant would address 316(b) requirements through the installation of a cooling tower.

3.3.9 Effluent Guidelines

On June 18, 2010, EPA forwarded an Information Collection Request ("ICR") to all coal-fired power plants and certain other plants, including nuclear. The purpose of the ICR is to collect information on waste water treatment technologies currently in use. Xcel Energy submitted our ICR responses to EPA in September 2010. EPA will now evaluate the need for changes to the effluent limit guidelines established under the Clean Water Act. The guidelines are periodically reviewed and, if warranted, changed to reflect improved water treatment technology performance. The timing for publishing revisions to the guidelines or new rules is unknown.

It should be noted that this rule will have greater impact if Units 3 and 4 are still operating on coal versus if the entire Plant is operating on natural gas. The repowered facility will be required to comply with the effluent limit guidelines but the amount of pre-treatment required prior to discharge under the NPDES permit is expected to be less than that required for coal operations.

3.3.10 Summary of Potential Emissions Control Rule Changes

Our assessments of the possible outcomes of the entire host of rule changes underway lead us to conclude that extensive additions and changes to pollution control will be needed for Black Dog Units 3 and 4 including the following:

- modern flue gas desulfurization ("FGD") scrubbers for removal of sulfur compounds and acid gases,
- selective catalytic reduction ("SCR") reactors for removal of NO_x,
- activated carbon injection ("ACI") systems for removal of Hg and organic compounds,
- fabric filter collectors for removal of particulate matter and metallic HAPs,
- installation of a cooling tower and possibly intake screen modifications for 316(b) compliance, and
- additional process water pre-treatment of ash contact water to comply with revised effluent limit guidelines.

3.4 Conclusion: Resource Needs

In Chapter 4, we describe the analysis we have done to examine the cost impacts of the possible capital investments necessary to continue to operate Black Dog Units 3 and 4. The analysis indicates that our system will be more efficient and cost effective over the long term if we cease operating Black Dog Units 3 and 4 and replace the 253 MW of generating capacity with a new resource as part of our plan to meet growing customer needs.

It is the combined need associated with continued growth in the customer demand in the range of 470 MW and the need to replace 253 MW of aging infrastructure that must be addressed to maintain a reliable, efficient, cost effective power supply for our customers.

3.5 Consequences of Project Delay

As shown above in Figures 3-5 and 3-6, significant resource capacity is needed on our system beginning in 2015. As we discuss in Chapter 4, the Project is the most cost effective alternative available to us, and will reduce exposure to the costs of future environmental regulations.

If this Project is delayed, we will likely need to purchase capacity and energy from short-term markets to bridge the delay. This will expose our customers to additional costs, as well as additional pricing volatility and reliability risk. If construction cannot begin in the spring of 2012, we will also see cost increases due to our estimates being dated. Obviously, the longer the Project is delayed, the greater the negative impact to our customers.

4 An Examination of Alternatives: Project is Most Reasonable and Prudent Alternative

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minn. R. 7849.0120). This section addresses the second criterion which provides that:

"a more reasonable and prudent alternative to the proposed facility has not been demonstrated by preponderance of the evidence on the record."

The Project results in a number of benefits for our customers. First, it adds about 450 MW of new capacity to our system to meet increased demand. It also replaces over 250 MW of aging resources that will otherwise require significant life extension investments and environmental upgrades in order to continue operating. The use of an existing site provides access to existing gas, transmission and other infrastructure that will result in reduced costs and enhanced reliability for our customers. The flexibility of the natural gas combined cycle technology will allow us to better integrate wind resources with dispatchable power supplies. Finally, the Project provides a significant hedge against future environmental costs and regulations. As a result, the Project is more reliable, more economic and more environmentally acceptable than other alternatives.

4.1 Alternative Evaluation Criteria and Project Objectives

To evaluate the reasonableness of the Project, we compared the Project to alternatives using multiple criteria. The results of this comparison demonstrate that the Project is the best alternative to meet the need identified in our 2010 Resource Plan.

The criteria considered in the development of the Project objectives and for evaluation of Project alternatives include the following:

- Cost

  Cost is an important factor in determining the reasonableness of any proposal. The Project has the lowest total system costs of the alternatives considered. In addition, the costs for the Project are more certain and involve less risk than other alternatives.

- Reliability

  It is critical that any generation resource we add to our system enables us to continue to provide our customers with reliable electric service. The existing Plant has a good reliability record, and our proposed Project in the same location will continue that record. In addition, the location within the metropolitan area provides additional reliability benefits. The transmission system that serves the metropolitan area around the Twin Cities has grown up around the Plant. Generation at this site supports the transmission grid for the entire metropolitan area.

- Environmental Impacts

  As we described in Chapter 3, we are in a period of unprecedented regulatory flux regarding continued operation of these coal fired units. In order to mitigate the risk posed by these potential environmental regulations, we have been working to reduce environmental impacts on our system. This Project will continue that trend by replacing 253 MW of coal generation with about 700 MW of efficient natural gas-fired generation resulting in lower emissions and lower risk for our customers.

- Appropriateness

  The Project results in meeting the appropriate size, type and timing of our resource need. We have system needs of 472 MW in 2016 (as shown in Figure 3-6), of which the Project can satisfy about 450 MW (the rest can be easily obtained through short-term capacity purchases). In addition, the Project will be able to operate in a flexible intermediate service mode that will allow us to better integrate the high level of wind resources on our system. Finally, the Project can be completed by January 1, 2016, in time to meet our customers' needs.

These criteria can be further explored in this proceeding as needed.

4.2 Alternatives Evaluation Approach

Minnesota Statutes Section 216B.243 and Minnesota Rule 7849.0250 set out a number of alternatives that must be discussed when considering the construction of a Large Energy Facility. Based on this direction, we have evaluated the following options as potential alternatives to the Project:

- Increased Efficiency of Existing Facilities, including transmission lines
- Purchased Power
- New Transmission Lines
- New generating facilities of a different size or type
- Increased Efficiency and DSM Efforts
- Distributed Generation
- Renewable Energy

Our evaluation of alternatives followed a multi-step process. First, we performed a qualitative screening to identify alternatives that have similar energy and capacity characteristics to the Project. Alternatives that were not reasonably applicable to the need or that were deemed to be excessively risky or costly were screened from further consideration. We then modeled the remaining alternatives in Strategist, comparing the system costs and environmental emissions from these options to those of the Project. Our findings confirm that the Project is the most cost effective project to implement at this time.

4.3 Qualitative Screening of Alternatives

4.3.1 Increased Efficiency of Existing Facilities

This Project continues our efforts to increase the efficiency of our generation fleet. Over the past several years, the Company has identified and implemented a number of efficiency upgrade projects. Our King, Riverside, and High Bridge facilities, which were all part of our Metropolitan Emission Reduction Program ("MERP"), were upgraded to increase efficiency and generation capacity. In addition, we are pursuing uprate/upgrade projects for our Prairie Island, Monticello and Sherco 3 generating units. Our aggressive pursuit of efficiency upgrades leaves few additional opportunities beyond this Project. For this reason, increased efficiencies at existing plants are not feasible to satisfy the intended need and we did not do further analysis.

4.3.2 Long-Term PPAs

Long-term PPAs are an important part of our resource mix. While we have not identified specific long-term PPAs that could potentially fill the need required by the Project, it is possible that competing proposals may be offered in this proceeding in the form of PPAs from independent power producers/developers. As part of this Certificate of Need process, it is expected that developers will be able to offer and advocate for competing proposals.

For an alternative to be considered, the developer must submit the alternative as part of this proceeding and include all information necessary to evaluate the alternative against the Company's Project. If a developer successfully demonstrates its alternative is superior, the Commission can direct the Company to negotiate a PPA with the developer instead of pursuing the Project. This process helps ensure the best value resource is selected.

Depending on the nature of the competing proposal, the PPA may have to be treated as a lease, either an "operating lease" or as a "capital lease" by Xcel Energy. Accounting guidance currently requires capital leases to be treated as long-term debt with a corresponding asset on the Company's balance sheet. Therefore, a PPA that must be treated as a capital lease can have a significant impact on the Company's capital structure. The result would likely be a higher debt to equity ratio and an impact to the cost of capital. Additionally, the impact to Generally Accepted Accounting Principles ("GAAP") recognized expenses resulting from accounting for either an operating lease or a capital lease may be different than the timing of cost recovery currently allowed which would make it necessary to seek to align our GAAP expense recognition with the allowed regulated cost of service to avoid material income statement impacts.

As part of the consideration in determining whether a specific PPA is a lease for financial reporting purposes, preparers and auditors look to the rights conveyed in an agreement from the owner of the assets to the party contracting to use the assets. If a purchase is determined to be a lease, the analysis turns to classifying the lease as an operating lease or a capital lease. In general, the more control and more risk conveyed to the purchaser, the more likely that the agreement will be considered a lease. Current accounting guidance under Accounting Standards Codification ("ASC") 840 requires that the facts and circumstance surrounding the transaction be reviewed to determine if lease treatment is applicable. Additionally, there are new proposed accounting rules that might require all leases to be recognized in a manner similarly to the capital lease treatment. These rules have been proposed by the Financial Accounting Standards Board ("FASB") in an Exposure Draft which may be finalized during 2011. Evaluating PPAs from a technical perspective is complex and can be challenging especially when key relevant facts are not available for consideration prior to negotiation of a written PPA.

In the case of a capital lease, the Company's balance sheet would have to show the capital lease as a fixed asset and an associated obligation that would be treated as long term debt. By recognizing a capital lease as a long term liability on the Company's balance sheet, the long term debt ratio in our capital structure increases adding the potential that equity infusions would be necessary to maintain the same economic capital structure. As previously mentioned, the timing and level of expense recognition associated with a lease will likely differ from the actual lease payments. Cost recovery should consider the higher expenses in the earlier years to reflect such a power purchase.

We identify these issues in this application to ensure that the Commission and interested parties are aware of the accounting issues and the impact they could have on customer rates. This impact will need to be incorporated into the evaluation of any PPA alternative in order to fairly compare it to the Project. If a competing PPA is offered, we look forward to working with parties toward this end.

4.3.3 Short-Term Purchased Power

Short-term purchases provide for flexibility in our resource portfolio. We typically acquire short-term power to meet unexpected increases in our load and to optimize the timing and cost of adding long-term resources. The price for short term resources varies with the market and can only be fixed for short periods of time. In addition, contracts for short term capacity do not always guarantee that energy will be delivered when it is needed.

Using short-term contracts to serve a substantial part of our long-term resource need would expose our customers to unacceptable levels of cost risk. In order to balance the benefits and risks of using short-term resources in our portfolio we work to limit our dependence on short-term purchases to something on the order of 300 MW annually. While we have some concerns about firm transmission service for these purchases, we believe this level of short-term power purchases provides the best level of benefits to our customers.

The resource need addressed by the Project is significantly greater than 300 MW. Thus, our assessment is that it would be too risky to rely on the short-term market to satisfy this resource need. Short-term purchases are not a prudent resource option to meet the long term need met by the Project.

4.3.4 New Transmission Lines

While additions to the electric transmission system could potentially provide access to additional generation resources to satisfy our resource need, new transmission is not a viable alternative for this Project. The underlying assumption with this alternative is that additional transmission infrastructure would provide access to new or existing capacity resources. We are currently unaware of additional generation resources that, with the construction of new transmission, could cost effectively provide our customers with the needed energy and capacity. Timing is also an issue when considering transmission as a viable alternative. Transmission capacity of any size can take several years to plan, permit, site and construct and would likely not be available in time to meet the customer need.

4.3.5 New Generating Facilities of a Different Size or Type

We considered a number of other potential generation projects. Most of those were discarded as not viable, at least within the timeframe when the resource is needed. Among a number of other issues, new nuclear, coal or hydro facilities cannot be constructed by 2016. Based on our screening of new generation facilities, however, we selected two major alternatives for further evaluation. The first would be to upgrade the existing Units 3 and 4 to allow for continued operation of these units and add additional new natural gas generation to meet the balance of the needed resources. The second option would be to construct new natural gas-fired generation at various sites to meet the full need, including the capacity currently provided by the existing

Units 3 and 4. As discussed below, to meet our requirements with respect to renewable energy sources, we also included a biomass generation alternative in our quantitative analysis.

4.3.6 Demand-Side Management

Our DSM programs are presented in more detail in Appendix C. Over the last few years, we have approximately doubled the amount of DSM we plan to obtain and as discussed in our 2010 Resource Plan, we have committed to achieving a 1.15% reduction in sales from DSM in 2010, 1.2% in 2011 and 1.3% in 2012 and continuing to ramp up to the statutory savings goal of 1.5%.

Meeting these goals each and every year will be very challenging. We will continue to launch new programs as well as expand existing programs in our efforts to attempt to meet the targets. We believe this aggressive expansion of DSM programs pushes the limits of achievable potential in our service territory and creates significant uncertainty regarding the size and timing of actual savings. As a result, it is unreasonably risky to rely on even more DSM in order to replace the energy and capacity from this Project. If DSM were to be selected as an alternative to the Project and the Company failed to achieve the necessary savings, we would be forced to buy replacement capacity and energy from the market, to the extent accessible, exposing our customers to higher costs, greater volatility and reduced reliability.

Therefore, the Company concluded that additional DSM saving beyond our current targets is not a feasible alternative.

4.3.7 Distributed Generation

Pursuant to Minnesota Statutes Section 216B.2426, we also considered the use of distributed generation to meet the need. In Minnesota, distributed generation ("DG") is defined generally as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, with a total capacity of no more than 10 MW.[3]

[3] In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212, Docket No. E-999/CI-01-1023, ORDER ESTABLISHING STANDARDS (September 28, 2004). Minnesota defines renewable projects between 10 and 40 megawatts as "dispersed" renewable generation (DRG). See Laws of Minnesota 2007, chapter 136, article 4, section 17.

Additionally, the capacity of the DG installation must be lower than the minimum load of the distribution system to which it would be interconnected, so that the energy generated by the DG facility is used locally.[4]

As discussed in Chapter 8 of our 2010 Resource Plan, we have undertaken a number of programs to promote the development of distributed generation on our system, and will continue to pursue and promote these technologies. However, we are not aware of available distributed generation resources in the quantities that would be necessary to replace about 700 MW that would be provided by the Project. In addition, based on available cost estimates for distributed generation resources, these resources would not be cost-effective. We therefore excluded this option from further consideration.

4.3.8 Renewable Energy Alternatives

There are four statutes that require the Company to look at various renewable energy options. The options we are required to address are: Community-Based Energy Development ("C-BED"), the impact of the Project on the Company's ability to meet the Renewable Energy Standard ("RES"), the availability of innovative energy alternatives and if there is a renewable resource that can meet our needs. We discuss each of these options below.

C-BED

Minnesota Statutes Section 216B.1612, subdivision 5 requires the Company to "take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements." We do not believe there are one or more C-BED projects available that would meet our needs. As discussed in Chapter 2 of this application, we are filing this application as a Track Two process. Thus, if there are any C-BED projects that believe they could meet the need required, we welcome their participation in this process. However, because we have conducted a number of RFPs to obtain C-BED proposals and continue to see C-BED projects miss in-service date requirements, we do not believe this is an option that could fulfill this need. Additionally, we have a need for a resource that can fill in the gaps when renewable energy projects are either not producing or are ramping up or down in their production. Thus, adding additional renewable

[4] See "Potential for and Barriers to State Jurisdiction Over Interconnecting Dispersed Generation Projects," Minnesota Office of Energy Security, June 6, 2008; and Phase II Report of the Technical Standards Workgroup Regarding Distributed Generation, MPUC Docket No. E999/CI-01-1023, Attachment 1, page 1.

energy that is variable in its production timing and availability will not fill the gap that is needed at this time.

RES

Minnesota Statutes Section 216B.243, subdivision 3(10) states that the Commission shall evaluate whether the applicant is in compliance with the applicable provisions of Minnesota Statutes Section 216B.1691 (the RES statue) and 216B.2425, subdivision 7. The RES requires the Company to obtain renewable resources such that 30 percent of retail electric sales are met by renewables by 2025. The Commission issued a letter on July 8, 2010 in Docket No. E999-PR-10-267 confirming that the Company was in compliance with the RES for 2009. Our compliance filing for 2010 is due on June 1, 2011. We will report compliance for 2010 in that filing. The Black Dog Repowering Project will not interfere with our ability to meet the RES requirements. If anything, this Project will help us better incorporate renewable resources because of their variable generation patterns.

Innovative Energy Alternatives

Minnesota Statutes Section 216B.1694 requires consideration of an innovative energy alternative as a supply option. There is no Innovative Energy Project currently being proposed. Thus we believe this Statute and its companion Clean Energy Technology Statute (Minn. Stat. § 216B.1693) do not limit this application. Nevertheless, as discussed in Chapter 2 of this application, we are filing this application as a Track Two process. Thus, if there are any innovative energy alternative projects available that could meet the need required, we welcome their participation in this process.

Meeting Need with Renewable Resource

Minnesota Statutes Section 216B.243, subdivision 3a requires the Company to evaluate renewable resources and show that the renewable resource is more expensive than the alternative selected. For this analysis, we have selected a biomass-powered facility as the best option available to us to meet the capacity and energy need in 2016. We selected this alternative to be modeled in the quantitative phase of the alternative analysis, despite significant concerns about the availability of adequate biomass resources, the potential costs of such resources and whether 700 MW of biomass generation could be permitted and constructed in time to meet the need.

4.3.9 No Facility

Minnesota Rule 7849.0340 also requires the Company to evaluate whether or not the alternative of no facility would be available to meet the needs of our customers. If the Project were not to be undertaken, we would experience a deficit starting in 2015. This deficit will grow to about 2,000 MW by 2024. Due to our requirement to provide safe, adequate and reasonable electric service pursuant to Minnesota Statutes Section 216B.04, "no facility" is not an option as we would experience a deficit in 2015 and beyond if the Project or an alternative is not undertaken.

4.4 Economic and Environmental Analysis

Based on the discussion in Section 4.3 above, we selected four alternatives for quantitative comparison using the Strategist model. These alternatives are:

- Life Extension

  Investing in the life extension and environmental control retrofits necessary to continue to operate Units 3 and 4 on coal while fulfilling the remaining need with new generation facilities;

- Repowering Project

  Cease operation of Units 3 and 4 and construct about 700 MW of combined cycle generation at the Black Dog Generating Plant site;

- Alternative Generation Model

  Cease operation of Units 3 and 4 and add necessary resources elsewhere on the NSP system to fulfill about 700 MW of need; and

- Biomass Alternative

  Cease Operation of Units 3 and 4 and fulfill the need with about 700 MW of biomass-fueled generation.

4.4.1 Strategist Modeling Tool

We use the Strategist resource expansion model[5] to analyze the impacts of various long-range electric supply and demand alternatives on our system. Strategist:

- Develops and ranks resource expansion plans that can meet our needs, given the input assumptions.
- Calculates the Present Value of Revenue Requirements ("PVRR") to measure the economic impacts of various planning scenarios.
- Calculates environmental impacts of the plan, using forecasted emission rates and externality values as applicable.

Strategist is useful as a planning tool in two ways. First, given a set of assumptions about the forecasted demand for electricity and the resources available to meet that demand, Strategist will optimize the operation of existing resources and add new resources to develop the expansion plan with the lowest PVRR possible.

We also use Strategist as a tool to determine the PVRRs of alternative cases. In this case, we insert a particular resource or an entire expansion plan into the model and the resulting PVRRs can be compared to other options to analyze the effects of different resource choices.

The Strategist model has some limitations. It is not a chronological dispatch model; that is, it does not simulate the operation of the system from hour to hour. The model is not able to simulate the ramp rate of units and other order-dependent variables that may affect the operation of the system. Instead, Strategist simulates system dispatch for each hour independently of what occurs before or after that hour. Overall, we have found Strategist to be a valuable tool for evaluating the impacts of long-term resource choices.

We have used the Strategist model to perform analyses presented in all of our Resource Plans since 2000, and in multiple other dockets since that time, including:

- Certificate of Need for the Blue Lake Generating Plant Expansion Project (Docket No. E002/CN-04-76);

[5] "Strategist" is a registered trademark of Ventyx. Ventyx developed and maintains the Strategist model.

- Certificates of Need for the Monticello Nuclear Generating Plant, to Establish an Independent Spent Fuel Storage Installation (Docket No. E-002/CN-05-123) and for Extended Power Uprate (Docket No. E002/CN-08-185;

- Certificates of Need for the Prairie Island Nuclear Generating Plant, for Extended Power Uprate (Docket No. E002/CN-08-509) and Additional Dry Cask Storage (Docket No. E002/CN-08-5100; and

- Petition for Approval of Power Purchase and Diversity Exchange Agreements with Manitoba Hydro (Docket No. E002/M-10-633).

4.4.2 Base Case Assumptions and Load Forecasts

The Strategist inputs used in this analysis are based on the assumptions used in the Company's 2010 Resource Plan. In order to ensure that the Commission has the best information available to make its decision, we have updated or refreshed the cost estimates for various resources as well as our fuel price forecasts and other assumptions.

We model our entire generation fleet in Strategist. Inputs for each unit include: maximum dependable capacity, firm capacity, heat rate profiles, emission profiles, maintenance schedules, forced outage rates, fuel cost, variable O&M, and fixed O&M.

Wind resources are modeled using representative hourly generation profiles. The nameplate capacity is multiplied by the hourly profile to estimate the units' generation. This enables Strategist to simulate the variability of wind and to predict the dispatch of thermal units needed to support these resources. Biomass plants are modeled much like other thermal plants and are dispatched on economic merit. Hydropower is modeled either as run-of-river where energy is provided at a constant rate, or as a dispatchable resource for hydro resources with pooling capabilities.

4.4.3 Black Dog Generating Plant Life Extension

Under this alternative, the 253 MW (2010 summer rating) of existing coal-fired generation at Black Dog Generating Plant Units 3 and 4 would be retrofitted to allow for 20 years of additional continued operation. This would require major equipment repairs or replacements for the turbines, generators, environmental control, boiler sections, feedwater heaters, pumps and electrical equipment. The equipment would not all be replaced at the same time unless it became prudent to include the work as part of a larger project for cost or regulatory reasons. However, we estimate that an investment of over $200 million in today's dollars would likely be needed to replace aging equipment.

The cost of complying with pending environmental regulations would also require new investments. For planning purposes we assumed that the EPA's Hazardous Air Pollutants MACT Rule will take effect by the end of 2014, although limits and implementation dates have not been set to date. In order to achieve high levels of HAPs reduction we envision the rule will require, a combination of ACI and a fabric filter dust collector would be needed. In order to be able to continue coal operations for an additional 20 years, emissions of SO_2 and NO_x would be reduced through the addition of a flue gas scrubber and SCR technology. Based on current information, the environmental investments would be in excess of $200 million needed in addition to the $200 million to replace aging equipment in today's dollars.

Because the capacity need in 2016 is greater than what would be provided by Units 3 and 4 in this scenario, Strategist selected two simple cycle combustion turbine units to be installed in 2016 to supplement the extended operations of Black Dog Units 3 and 4.

4.4.4 Black Dog Repowering Project

As part of this Project, we will discontinue coal operations at Units 3 and 4 in 2013, but the Units will still be available to generate using natural gas as a boiler fuel. While for economic reasons the Units would be unlikely to dispatch as often on natural gas as they did on coal, switching to natural gas will allow the current capacity to remain available throughout the construction period, and continue to generate energy when it is needed. About 700 MWs of combined cycle generation will be constructed in the area reclaimed from the existing coal storage yard and will be in commercial operation by January 2016.

The combined cycle facility is based on "F" class combustion turbines, heat recovery steam generators with supplemental duct firing for additional peak generation capability, and a single condensing steam turbine. Facility cooling will utilize the cooling water currently allocated to the existing Plant. The combustion turbines will be fueled by natural gas. The output will be stepped up to 345 kV at a new substation and transported over a short distance of new 345 kV lines to the existing 345 kV transmission lines which run through the Black Dog Generating Plant site property.

4.4.5 Alternative Generation Option

Under this scenario, we ceased operating Units 3 and 4 at the end of 2014. We allowed Strategist to select new generic resources to replace the output of these units and to meet any additional resource needs. Strategist selected three combustion turbines to be installed between 2015 and 2017 to satisfy the capacity need for this period, including the retirement of Black Dog Units 3 and 4.

4.4.6 Biomass Alternative

Under this alternative, 700 MW of biomass-fueled generation would be added in 2015 and 2016. We used available engineering data to estimate the cost of these units. As shown in Table 4-1 below, the Biomass Alternative was approximately $2.5 billion more expensive on a PVRR basis than its closest alternative.

Notwithstanding the cost of a biomass option, it is unlikely that we would be able to procure sufficient biomass to fuel this amount of capacity. The availability of biomass as a fuel for generation has been a technical and economic challenge for much smaller generation projects than those contemplated under this option, and has been a very contentious issue relative to alternative uses of biomass.

4.4.7 Modeling Results

Our Strategist results indicate that the Black Dog Repowering Project alternative is the most cost effective option we evaluated and is on a PVRR basis $146 million less than the Alternative Generation Option (its closest competitor). This cost differential is primarily due to the Project benefits that include re-using an existing site, water systems and other facilities. Further, this PVRR difference does not capture other benefits such as use of existing transmission capacity, which are not modeled as part of generic units in Strategist.

The Black Dog Repowering Project PVRR is also about $485 million lower than the Black Dog Generating Plant Life Extension alternative (see Table 4-1 below).

Table 4-1: Cost Comparison of the Strategist System Expansion Plan with the Black Dog Repowering Project as Compared to Plans with Alternatives ($000s)

	PVRR	Difference from BD Repowering
Black Dog Repowering Project	$99,940,255	---
Alternative Generation	$100,086,164	$145,908
Black Dog Life Extension	$100,425,262	$485,007
Biomass Alternative	$102,944,542	$3,004,287

We also compared the Black Dog Repowering Project against the Alternative Generation and Life Extension options across a range of sensitivities. As shown below in Table 4-2, the PVRR's of the Black Dog Repowering Project are much lower than those of the other options across all sensitivities.

Table 4-2: Cost Sensitivity Analysis – PVRR Comparison

	Plan with Black Dog Repowering Project ($000)	Alternative Generation Diff from Plan ($000)	BD Life Ext Diff from Plan ($000)
Base ($0 CO_2)	$99,940,255	$145,908	$485,007
High Gas (+20%)	$101,310,664	$160,236	$346,408
Low Gas (-20%)	$98,559,307	$126,683	$617,448
High Load (80th Percentile	$105,222,853	$181,340	$509,419
Low Load (20th Percentile)	$96,401,192	$51,512	$392,089
High CO_2 ($34/2012)	$110,865,165	$216,190	$977,875
Mid CO_2($17/2012)	$105,403,747	$171,709	$721,338
Low CO_2($9/2012)	$102,826,842	$161,287	$609,578
Very High Capital Expenditures(+20%)	$100,074,311	$11,853	$350,952

	Plan with Black Dog Repowering Project ($000)	Alternative Generation Diff from Plan ($000)	BD Life Ext Diff from Plan ($000)
High Capital Expenditures(+10%)	$100,007,283	$78,880	$417,979
Low Capital Expenditures(-10%)	$99,873,228	$212,936	$552,035
No MISO Market	$99,991,181	$175,762	$484,403
High Externalities	$100,276,105	$142,517	$517,172
Low Externalities	$100,069,066	$143,490	$507,332

We also reviewed the differences in the fuel mix for the life extension versus the Black Dog Repowering Project as there has been a concern in the past that by adding more natural gas units we would be disproportionally expanding the amount of gas used on the system. As shown in the figures below, this is not the case.

Figure 4-1: Fuel Use with

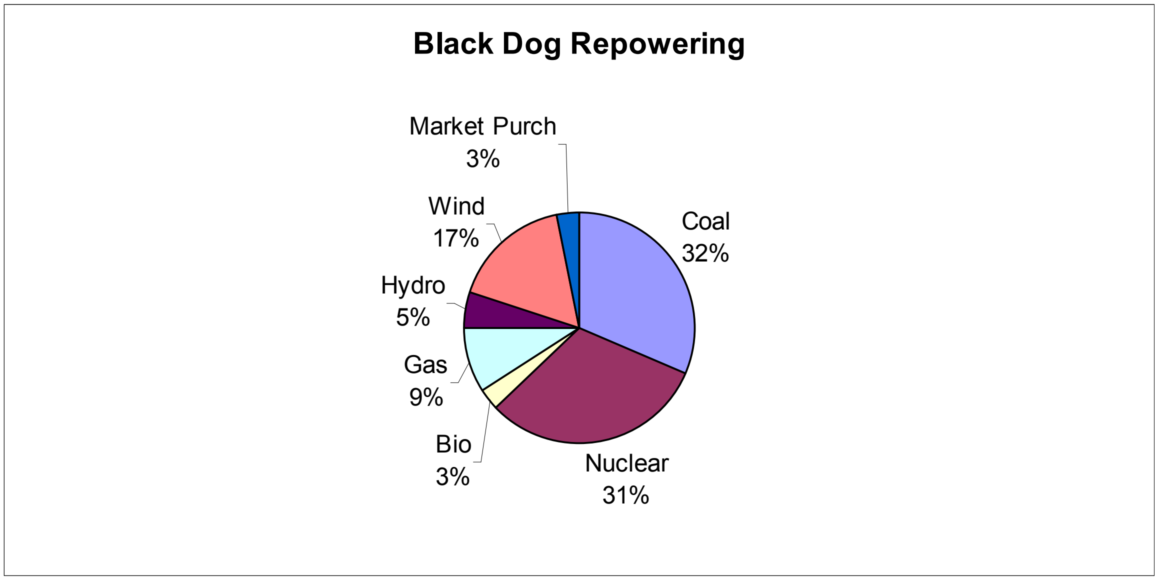
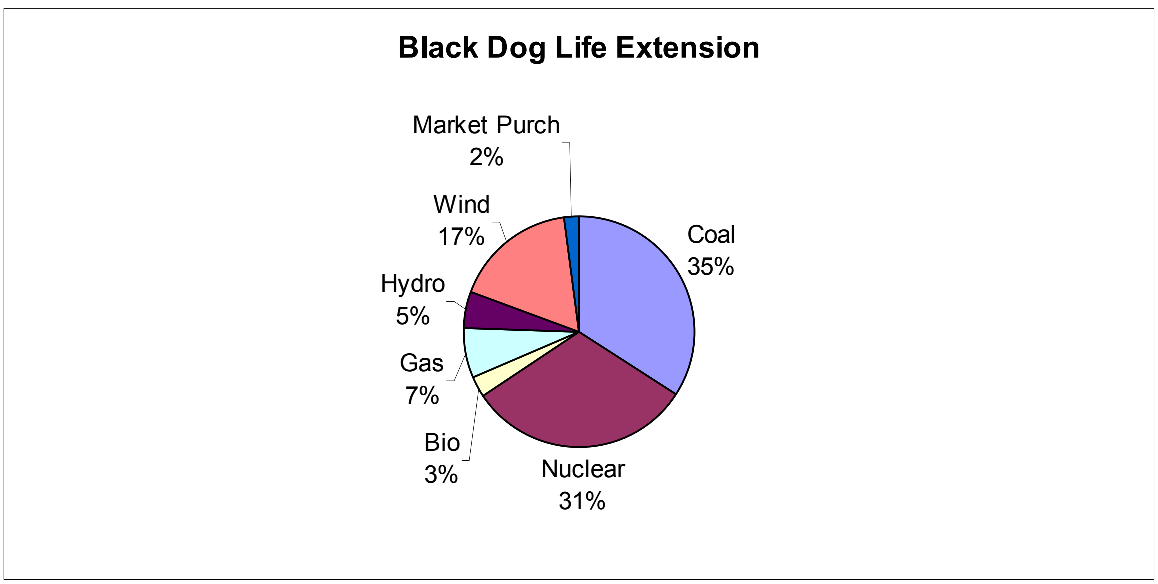


Figure 4-2: Fuel Use with



4.4.8 Cooling Tower Sensitivity

As part of the Project base costs, we include $22 million for a cooling tower. This is the incremental portion of the full cost of a cooling tower that would be assigned to the Project. We also tested a scenario where the entire cost of a cooling tower would be allocated to the Project. This case could arise in the event that it is conservatively assumed that a cooling tower would not be required for Unit 5/2 absent the Project. The entire cost of a cooling tower would be approximately $70 million. Our analysis of this sensitivity is shown in Table 4-3 below which demonstrates that except under extreme circumstances, the Project would continue to be more cost-effective than the other options.

Table 4-3: Cooling Tower Sensitivity
PVRR Comparison of Project to Alternatives

	Black Dog Repowering Project ($000)	Alternative Generation Diff from Project ($000)	Life Ext Diff from Project ($000)
Base Case ($0 CO_2)	$99,994,913	$91,251	$430,350
High Gas (+20%)	$101,365,322	$105,579	$291,751
Low Gas (-20%)	$98,613,964	$72,026	$562,791
High Load (80th Percentile)	$105,277,510	$126,682	$454,761
Low Load (20th Percentile)	$96,455,849	($3,145)	$337,431
High CO_2 ($34/2012)	$110,919,822	$161,533	$923,218
Mid CO_2 ($17/2012)	$105,458,404	$117,052	$666,681
Low CO_2 ($9/2012)	$102,881,500	$106,630	$554,921
Very High Capital Expenditures (+20%)	$100,128,968	($42,804)	$296,294
High Capital Expenditures (+10%)	$100,061,940	$24,223	$363,322
Low Capital Expenditures (-10%)	$99,927,885	$158,279	$497,377
No MISO Market	$100,045,838	$121,104	$429,746

	Black Dog Repowering Project ($000)	Alternative Generation Diff from Project ($000)	Life Ext Diff from Project ($000)
High Externalities	$100,330,762	$87,860	$462,514
Low Externalities	$100,123,724	$88,832	$452,674

4.4.9 Delay Scenario

The timing of the investments in the life extension scenario depend in part on the implementation dates of the Hazardous Air Pollutants MACT Rule, with compliance dates currently expected to be 2014. To examine the effect of a delay in those requirements, we also evaluated a scenario where we pushed out the implementation of the Black Dog Repowering Project until 2018. Under this scenario, we would discontinue coal operations in 2015 and construct the combined cycle to be in service by January 1, 2018.

The delay scenario did not show that there would be any benefits to delaying the implementation of the Black Dog Repowering Project to 2018, even if compliance date for the Hazardous Air Pollutants MACT Rule was delayed for two years. This is because the Company still requires new capacity in 2016 to meet customer demand, and the delay of the Project would necessitate the implementation of at least two combustion turbines in 2016. The result of the delay would be a swap between the Black Dog Repowering Project and Combustion Turbines that currently show up as additions in our 2010 Resource Plan in 2018 and 2019.

4.4.10 Emissions

Table 4-4 below shows the system emissions are significantly lower with the Project than the system emissions assuming the alternative scenarios for a number of critical types of emissions. Given the abundance of federal emissions regulations that are pending over the next few years as discussed in Chapter 3, reducing our emissions increases our ability to meet compliance requirements and reduces the operational challenges associated with providing service to customers while at the same time implementing compliance programs. It should be noted that our estimates of system emissions did not attempt to account for emission reductions that may be necessary at other plants on our system as time passes. Actual system emissions under each scenario will probably be lower but the comparisons are still valid.

Table 4-4: Emissions Differences between the Black Dog Repowering Project and the Alternatives (Total System Tons Emitted 2010-2049)

	Black Dog Repowering System Total	Alternative Generation	Black Dog Life Extension
		Diff from Repowering (+/-)	
SO_2	1,094,300	+ 27,136	-2,128
NO_x	753,436	+ 17,370	+3,851
CO_2	948,195,698	+ 5,296,874	+ 36,391,168
CO	129,064	+ 3,660	+ 9,335
PM10	109,084	+ 211	+ 7,000
VOCs	20,535	- 1,312	- 647
Mercury	15.4	+ 0	+ 1

4.5 Alternatives Evaluation: Project is the Best Option

Based on the alternatives that were considered above, the Project is the best option to meet our resource needs beginning in 2016. In addition to meeting the capacity requirements, the Project reduces potential cost by using highly efficient combined cycle combustion turbine technology at an existing site with access to existing natural gas and transmission infrastructure. It improves both the flexibility of our generating fleet and the environmental profile of our system. On a life-cycle basis, the Project cost is estimated to be substantially lower than options that propose new generation elsewhere on our system.

4.5.1 Best for Service Need

The Project is the best option for addressing the need for more flexible resources on our system. As our wind portfolio continues to grow, our greatest need is for resources that can adjust load quickly to meet unserved demand as the wind waxes and wanes. The combined cycle technology is well-suited to meet our load-following objectives because of its ability to be brought into service quickly and operate efficiently at a range of outputs for variable durations. The coal-fired life extension option and simple cycle technology-based generation that could otherwise be used to meet our needs cannot be operated as cleanly, efficiently and economically as this combined cycle Project.

4.5.2 Best for System Reliability

The Project is the best option for enhancing the reliability of the bulk electric system. Locating the Project at an existing site within the metropolitan Twin Cities' transmission beltway furthers system reliability because the resource is close to the load, thereby reducing strain on an already taxed regional transmission system and system losses. Additional reliability is provided through use of the combined cycle technology which is among the most reliable generation technologies. The Project will include firm gas supply contracts to address fuel reliability without the need for a backup fuel oil supply.

4.5.3 Best for Environment

This Project also provides the lowest environmental impacts of the options studied. This Project allows the Company to leverage existing generation infrastructure while at the same time employing proven, efficient and environmentally-friendly technology. The air emissions are significantly lower than the existing coal-fired units as well as the other alternatives studied. All other options studied would likely result in the need for new greenfield sites to construct new simple cycle generation and transmission lines elsewhere. Retiring Black Dog Units 3 and 4 presents an important opportunity and moment in time to modernize our generating fleet and take advantage of a unique location and the infrastructure that has developed there over the years. If the site is not redeveloped now we may loose the chance to realize the site's benefits in the future as land use patterns change.

4.5.4 Most Cost Effective

The Project is the best option to enhance customer value and reduce risk by leveraging existing generation, transmission and natural gas pipeline capacity contracts and renewing aging facilities. The economic analysis developed in the Strategist modeling indicates the Project has the lowest total system cost of the available alternatives under nearly every scenario considered. In addition, the costs for the Project are more certain and involve less risk than other alternatives. The Project further protects Xcel Energy customers from short-term energy price volatility and provides a hedge against the cost of future environmental regulations.

4.6 Rate Impact

The rate impact differences between the alternatives are relatively small, especially over time, but the Project has the lowest rate impact over the next 10 years as shown in Table 4-5 below.

Table 4-5: Percent Increase in Rates for the Black Dog Repowering Project and Alternatives

Rate Impacts over Time	Percent increase in rates for each alternative over the selected time frame		
	2010-2020	2010-2030	2010-2049
BD Repowering Project	2.98%	2.78%	1.60%
Alternative Generation Option	3.01%	2.78%	1.61%
Black Dog Life Extension	3.07%	2.79%	1.62%

We are also required to provide a first year rate impact of the Project. The effect of this Project in 2016 would increase customer prices by $0.002221 per kWh. We believe that the price increase when combined with the flexibility, reliability and environmental benefits provides a reasonable impact to customers. Furthermore, there is no more reasonable and prudent alternative to the Project.

5 Project Description

This chapter provides a description of the existing Black Dog Generating Plant, the changes necessary to repower Units 3 and 4, the new 345 kV substation, modifications to a section of existing lines and the new 345 kV transmission lines that will encompass the entire Project. Table 5-1 contains the operational information on the existing units as required in the Commission's application content rules, Minnesota Rule 7849.0250(A), Minnesota Rule 7849.0320(C) and Minnesota Rule 7849.0320(E).

5.1 Existing Plant Information

The Black Dog Generating Plant is a coal- and gas-fired generating station, located on the Minnesota River just south of the Twin Cities.

The original Unit 1 boiler/turbine and the Unit 2 boiler, installed in the 1950s and fired on coal, were repowered with a natural gas combined-cycle unit (Unit 5), which includes a natural gas combustion turbine-generator combined with a HRSG. Exhaust heat from Unit 5 powers the Unit 2 steam turbine. The repowering project, completed in summer 2002, increased output from the two original units by more than 100 MW, and resulted in greater operating efficiency and cleaner power production.

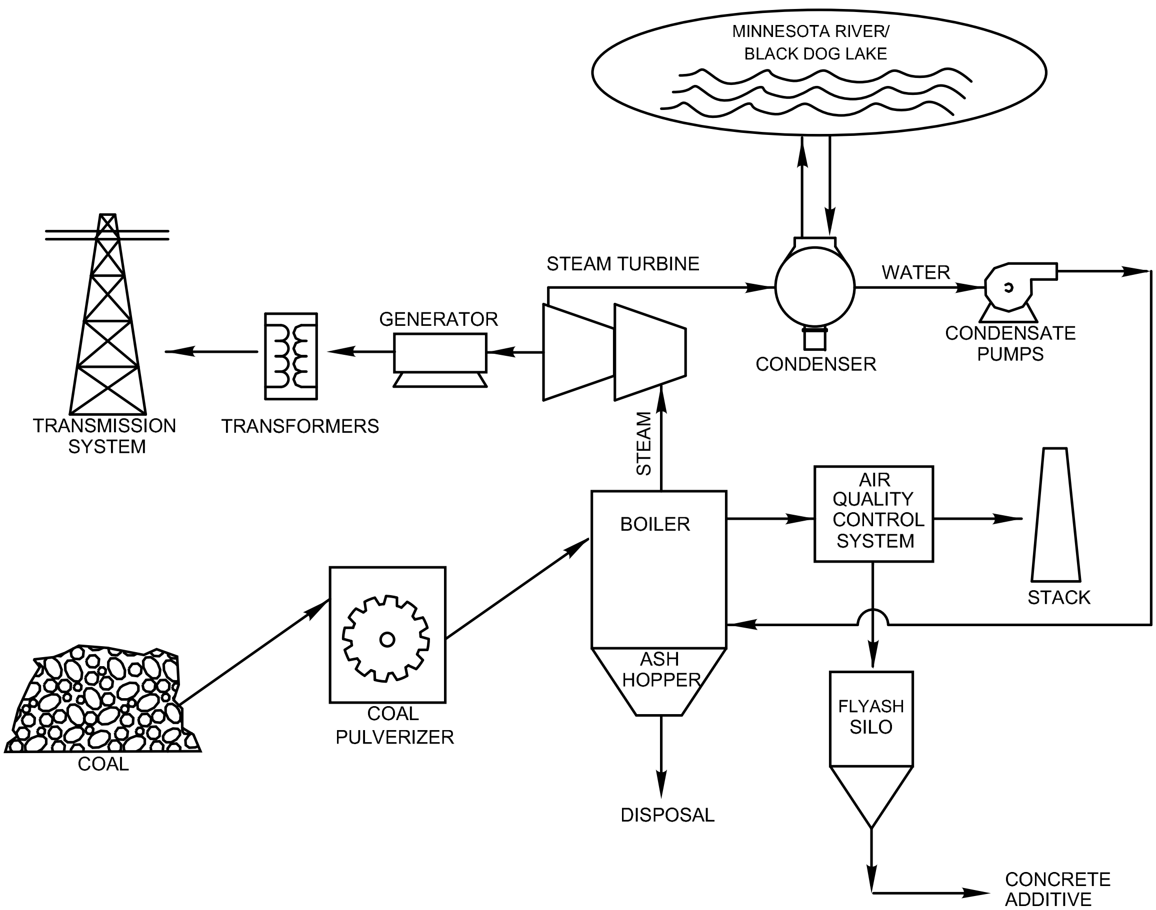
Black Dog Units 3 and 4 were put into service in 1955 and 1960, respectively. Units 3 and 4 are dual-fuel boilers with steam turbines that utilize coal as the primary fuel. Natural gas is the backup fuel that can be used to obtain maximum generation from both units. The boilers, turbines and generators are essentially original equipment which have been well maintained and operated over their entire lives. However, operating data shows a declining availability as the units continue to age. They were originally designed for a 35 year life and have recently exceeded 50 years of operation. At the proposed time of retirement in 2016, Unit 3 will have operated for 60 years and Unit 4 for 55 years.

If the units continue to operate beyond the proposed 2016 retirement date, they will require significant investments due to aging equipment and pending regulatory changes.

In our 2007 Resource Plan, we indicated we would be studying options for Units 3 and 4. The submittal of this Certificate of Need filing is the result of the evaluation process that we have completed and discuss in our 2010 Resource Plan.

The process by which Units 3 and 4 convert the energy in coal (or natural gas) to electrical energy for customers is shown schematically below in Figure 5-1.

Figure 5-1: Coal Fired Plant Schematic Diagram



The process begins with the conveyance of coal into the Plant where it is pulverized and then blown into the boiler and combusted. The exhaust from the boiler passes through an electrostatic precipitator that removes fly ash in the exhaust stream before going up the Plant stack. The heat generated by the boiler is used to convert water to steam that then passes through a turbine to turn the turbine rotors. The turbine shaft is connected to a generator that converts the rotational mechanical energy from the turbine shaft to electrical energy. After transferring its usable energy in the turbine, the steam is cooled further in a condenser and then returned to the boiler to repeat the cycle.

Table 5-1: Existing Black Dog Generating Plant Units 3 and 4 Operational Information

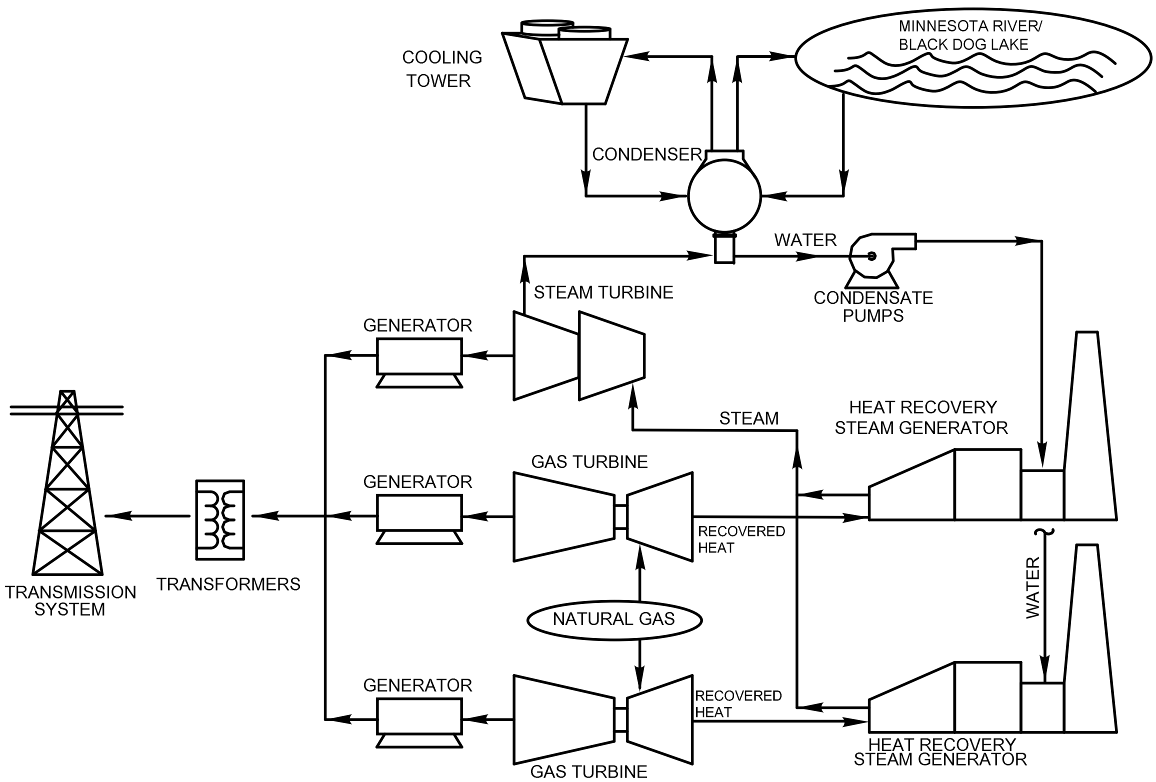
Description	Unit 3	Unit 4
General Data		
Nominal Generating Capability	89 MW Net	164 MW Net
Operating Cycle	Steam Rankine	Steam Rankine
Annual Capacity Factor	< 60 percent	< 70 percent
Actual Efficiency	30.3% (net)	32.5% (net)
Annual Availability	78%	90% (Apr – Oct)
Land Requirement	< 1 acre for each Unit, total Plant site is approximately 35 acres out of a 1,900 acre site	
Fuel Data		
Fuel Source	Low-sulfur western coal Natural Gas – CenterPoint	Low-sulfur western coal Natural Gas – CenterPoint
Fuel Requirement Primary - Coal Secondary – Natural Gas	49.9 tons/hr coal with 0.16 million SCF/hr natural gas	94.5 tons/hr coal with 0.13 million SCF/hr natural gas
Heat Input (HHV)	1001 MMBTU/hr	1,724 MMBTU/hr
Fuel (Coal) Heat Value (HHV)	8,450 BTU/lb	8,450 BTU/lb
Fuel (Coal) Content:		
Sulfur	0.21%	0.21%
Ash	5.2%	5.2%
Moisture Content	27.5%	27.5%
Water Use	**Entire Plant Use Shown Below**	
Maximum Groundwater Pumping Rate	250 GPM peak, 200 GPM daily average	
Average Annual Groundwater Use	37 million gallons or 114 acre-feet (past 5 year annual average)	
Annual Surface Water Consumption	104,000 million gallons or 319,000 acre-feet (past 5 year annual average)	

Units 3 and 4 are currently used as intermediate to base load facilities.

5.2 Description of Proposed Fuel and Operating Cycle

Combined cycle is an electric generating technology in which electricity is produced from otherwise lost heat exiting from one or more combustion turbines. The heat exiting the combustion turbine(s) is routed to a HRSG to generate steam for utilization by a steam turbine-generator set. This process increases the efficiency of the electric generating unit. The steam from the steam turbine generator is exhausted to the condenser to be converted back to water for reuse in the HRSG. The condenser requires cooling water to cool the steam and convert it back to water. In the cooling process heat is transferred to the cooling source. The Project is expected to use a combination of the Minnesota River and a cooling tower for cooling as shown below in Figure 5-2.

Figure 5-2: Schematic Diagram of a 2 on 1 Combined Cycle Facility



Major components of the Project include:

- Combustion Turbine-generators
- HRSGs and exhaust stacks
- Steam turbine generator, condenser and cooling tower
- Transformers

Combustion Turbine-generators
The design capacity of the Project is based on the performance characteristics of an F class combustion turbine (similar to the existing Unit 5) with supplemental firing to increase steam generation to the steam turbine. In a typical unfired combined cycle plant, the combustion turbine capacity is approximately double the steam turbine capacity.

Each combustion turbine-generator consists of the following equipment in series:

Inlet Air Filter

Compressor, where air is drawn in and compressed

Combustor, where the air/fuel mixture is ignited

Power Turbine, where the combusted gases expand to rotate a turbine

Generator set

HRSG and Exhaust Stacks
The Project includes two HRSGs – one matched with each combustion turbine. The exhaust gases exit each combustion turbine and flow directly into the HRSG. Inside the HRSG, the hot exhaust gases are directed across the heat transfer tube surfaces causing the water in the tubes to boil and change into steam. The HRSGs are also equipped with natural gas-fired duct burners that can be used to input additional heat to increase the steam generating capacity of the HRSGs. Each HRSG will be approximately 95 feet tall, 40 feet wide, and 140 feet long.

After passing through the HRSG, exhaust gases from each combustion turbine generator will discharge through a steel stack. Each stack will be approximately 19 feet in (inside) diameter.

The two combustion turbines will provide exhaust heat to produce sufficient steam to generate approximately 50 percent more output with the steam turbine. Supplemental duct firing of the HRSGs to increase their steaming rate will allow the Project to capture the full load capability of the steam turbine during periods when peak output is desired.

Steam Turbine Generator, Condenser and Cooling Tower
A single steam turbine will receive steam produced by the two HRSGs. Steam received from the HRSGs will be expanded through a reheat steam turbine and will rotate the turbine shaft. The energy produced by the expanding steam will rotate the turbine shaft, which drives a generator to produce electrical power.

Exhaust steam from the steam turbine will be condensed within a water-cooled steam surface condenser. The condensed steam collects in the bottom of the condenser from which it is pumped back to the HRSGs to be reused to generate steam. Cycle heat removed from the condensing steam in the condenser is absorbed by circulating water flowing through the condenser tubes. Heat absorbed by the circulating water will be rejected to the river, or to the cooling tower. Circulating water pumps will pump circulating water from the river intake or the cooling tower through the condenser to Black Dog Lake or the cooling tower.

Transformers
The three generator stepup transformers will be located next to the generation block. The transformers increase the output voltage of the three generators to the 345 kV substation voltage. Auxiliary transformers will be used to convert some of the output power to lower voltages for use in the Project's auxiliary equipment.

5.3 Location and Land Use

The Project will be located on 35 acres within the exiting Plant site. The Plant site is located in Burnsville, Minnesota and is approximately 15 miles south of Minneapolis and east of the City of Eagan (see Figure 1-1).

The Plant is located in Township 27N, Range 24W, Sections 23 and 24 in Dakota County. The Plant for the most part is separated from commercial and residential areas by Black Dog Lake, the Union Pacific Railroad and the Company's railroad spur, Black Dog Park and the Minnesota River. There is forest land along each side of the Union Pacific Railroad and open and scattered forest south of Black Dog Lake where the two proposed double circuit 345 kV transmission lines will connect with the existing 345 kV transmission lines.

Current USGS Landuse/Landcover database information characterizes the Plant site as consisting of primarily Developed and Barren land with a small segment of Open Water overlaying the Plant ponds and intermittent strips of deciduous forest outlying the Plant's southern boundary and along the Xcel Energy railroad spur.

The Plant property covers about 1,900 acres south of the Minnesota River in Burnsville. The total acreage includes the Plant site covering about 80 acres, which entails the powerhouse, coal yard, substation, settling ponds, and Black Dog Lake (used for cooling) covering about 500 acres. The majority of the remaining property (1,250 acres) is managed as part of the Minnesota Valley National Wildlife Refuge under a 1982 lease and agreement with the U.S. Fish and Wildlife Service.

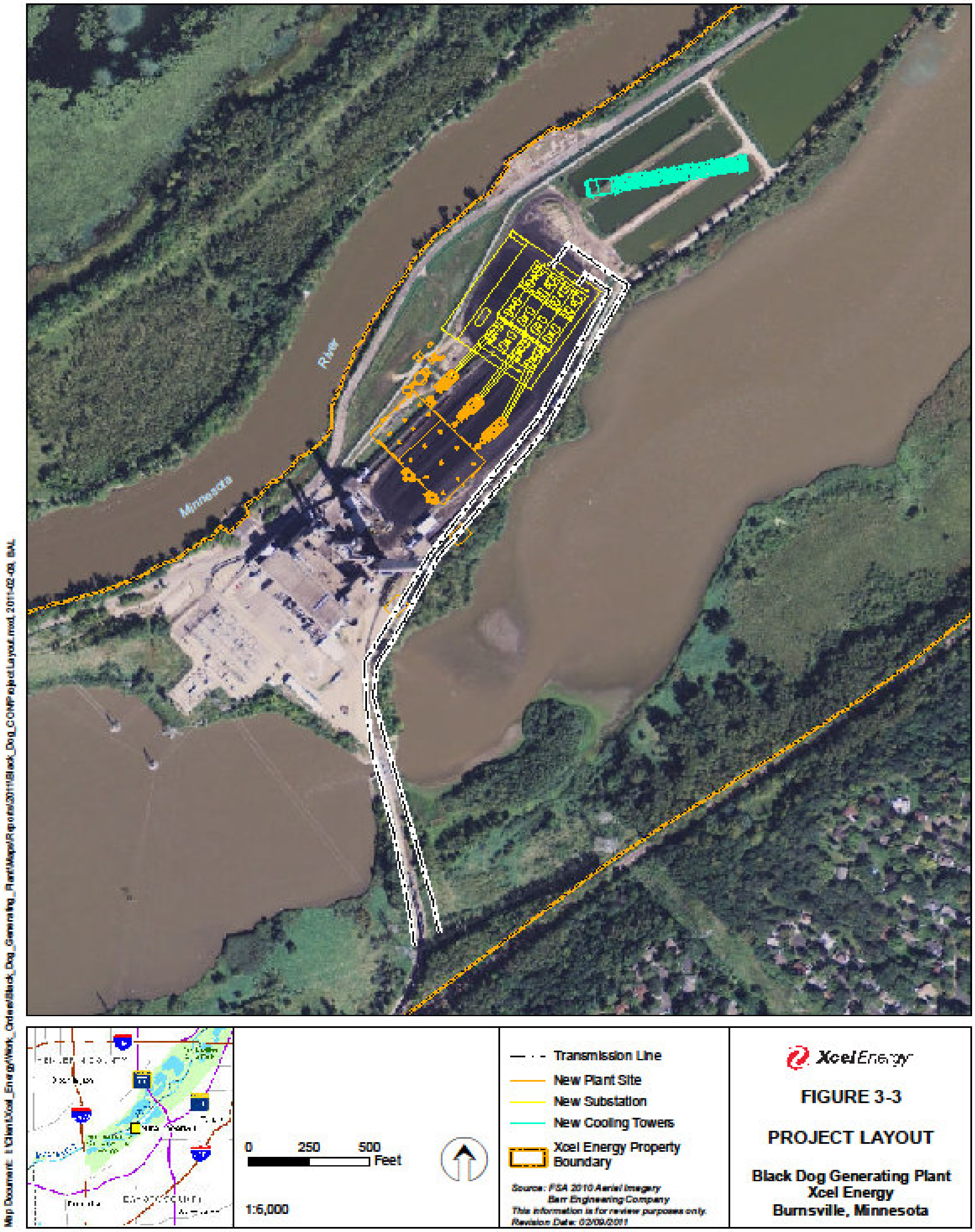
Established in 1976, the Minnesota Valley National Wildlife Refuge stretches over 50 miles between Fort Snelling State Park and Belle Plain, Minnesota, and provides habitat for a large number of migratory waterfowl, fish, and other wildlife species (FWS, 2010; http://www.fws.gov/Midwest/MinnesotaValley/intro.html). The Refuge offers a variety of year-long and free outdoor recreational activities, and has two education and visitors centers, which are located over 5 and 40 miles, respectively, from the Plant site. The Minnesota Valley National Wildlife Refuge is well known for bird watching, which is available year-round. Other recreational opportunities include wildlife observation, wildlife photography, hunting, fishing, environmental education, and interpretation. According to the FWS' website (2010; http://www.fws.gov/Midwest/MinnesotaValley/intro.html), overall management of the Refuge involves "restoring wetlands, grasslands, and oak savannas, enhancing aquatic plant diversity through water level management, grassland management, exotic species control, and water quality monitoring."

We began a cooling lake drawdown program in 1989 in cooperation with the U.S. Fish and Wildlife Service to enhance wetland vegetation growth in Black Dog Lake and thereby increase migratory bird use. The cooling ponds allow some birds such as the American woodcock to remain in the area longer in winter. The Plant site and proposed Project layout is shown in Figure 5-3.

About 350 feet south of the Project area is Black Dog Park, a 38-acre park that includes softball/baseball fields, a football field, walking trails and natural areas (http://www.ci.burnsville.mn.us/index.aspx?NID=269). The closest park-related facilities to the Project include a softball/baseball field, which is located about 750 feet west and primarily used during the spring, summer, and autumn months. About 200 feet south of the Project area is a walking trail along the south side of Lyndale basin of Black Dog Cooling Lake. The Project is not expected to impact Black Dog Park or walking trails.

In addition to the previously discussed Minnesota Valley National Wildlife Refuge, the primary tourism activities in the region include camping, recreational use of the regions lakes for fishing and boating, bicycling, hiking, bird or wildlife viewing, or cross country skiing.

Figure 5-3: Project Layout



5.4 Structures and Structure Height

The Project components will be located primarily within the existing Plant coal yard area. A new 425 foot by 280 foot by 140 foot tall structure will be built in the current coal yard area. New components that will be located in the new enclosed structure are two combustion turbine-generator sets, two HRSGs, and one steam turbine-generator. Two air inlet filters will be located on the exterior of the structure and five new transformers will be located adjacent to the new facility structure. A new 345 kV substation will be constructed next to the generation block. Three water tanks and two ammonia storage tanks will also be added outside the new Plant structure. The exhaust stacks will be approximately 230 feet tall and will be located adjacent to the new structures. The new transmission towers will be between 90 and 110 feet tall. The transmission infrastructure associated with the Project is described in Section 5.8. A cooling tower will likely be located where the current ash ponds reside. The height of the cooling tower will be approximately 70 feet tall.

5.5 Project Output

The output of the Project depends on ambient weather conditions (primarily temperature and humidity) and the operating mode of the HRSG (with or without duct-firing). For purposes of this application, nominal generating capacity is considered to be about 700 MW. The Project will operate at maximum efficiency without duct firing. Therefore, it is a competitive unit to meet intermediate load needs.

5.6 Project Sizing

The design capacity of the Project is based on the current performance characteristics of an F class combustion turbine (similar to the existing Unit 5) with supplemental firing to increase steam generation to the steam turbine. In a typical unfired combined cycle plant, the combustion turbine capacity is approximately double the steam turbine capacity. The two combustion turbines will provide exhaust heat to produce sufficient steam to generate approximately 50% more output with the steam turbine. Supplemental firing of the HRSGs to increase their steaming rate will allow the Project to capture the full load capability of the steam turbine during periods when peak output is desired.

5.7 Fuel Use

The Project will be fueled entirely by natural gas with no backup fuel. We expect to secure firm natural gas supply contracts.

5.8 Transmission

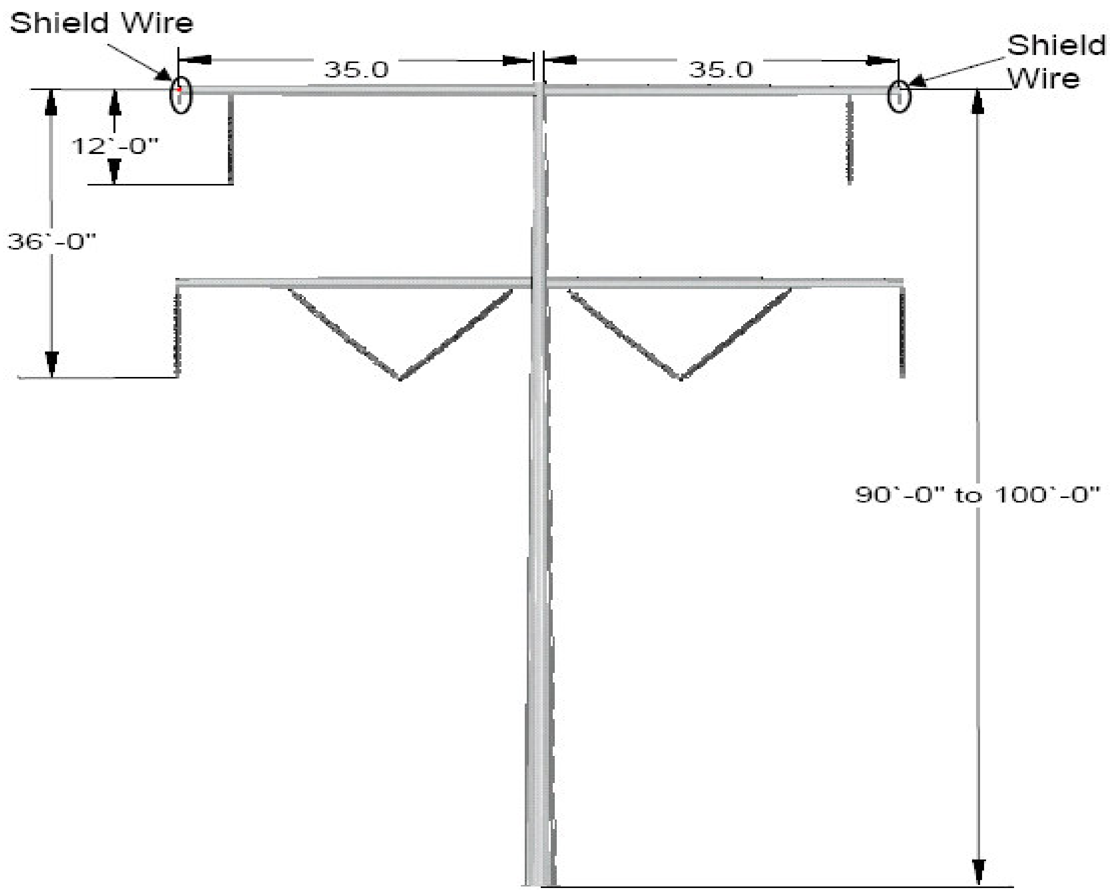
The Project will be connected to the bulk transmission system through a new 345 kV substation. The electric transmission components of the Project consists of building two double circuited, 345 kV transmission lines that will be approximately 4,000 feet long and reconfiguring a 1,000 to 1,500 foot-long section of existing transmission line. The reconfiguring stems from the need for the new lines to cross over two existing 115 kV lines, precipitating the need to adjust the height of the 115 kV lines for this purpose. The proposed location of the substation and the proposed route of the 345 kV lines are shown above on Figure 5-3. The new lines will connect the new 345 kV substation to the existing Blue Lake to Prairie Island 345 kV transmission line and the Blue Lake to Inver Hills 345 kV transmission line. Both of these lines currently run through the Plant site so all transmission work will be done within existing Xcel Energy property.

The proposed structures (see Table 5-2 and Figure 5-4 below) for the 345 kV double circuit lines will be about 90 to 110 feet tall and will have an average span between 300 and 500 feet. The finish of the proposed poles will be galvanized steel. The existing transmission line structures in this area are wood poles of H-frame construction, and galvanized steel lattice design. The proposed steel poles will give the new transmission line a somewhat cleaner and more modern appearance. The conductor will be bundled, 795 KCmil 26/7 ACSR. Conductor Specifications are presented in Appendix E.

Table 5-2: Structure Design Summary

Line Type	Structure Type	Structure Material	Right-of-Way Width (feet)	Structure Height (feet)	Foundation	Foundation Diameter (feet)	Span Between Structures (feet)
345 kV Double Circuit	Single pole,	Galvanized steel	150	90-110	Concrete	8 to 10 foot concrete	300 to 500

Figure 5-4: Double Circuit Transmission Line Structure



5.9 Natural Gas Pipeline

CenterPoint Energy currently serves the Plant site. We will be securing additional natural gas supply through a competitive process beginning in early 2012. We anticipate that the successful bidder will file for a route permit and other necessary permits to replace the existing pipeline serving the Plant with a new higher pressure natural gas line.

5.10 Construction

5.10.1 Generation Block

Generation block construction will begin after approvals are obtained. Site preparation and fill to bring the Project area above the 100 year flood level is anticipated to start in 2012. Installation of pilings and construction of foundations will start the following year. Building erection and installation of the large components would occur in 2014. In 2015, construction completion and startup of the facility would occur.

The Project is expected to be in commercial operation by January 2016. Below we describe the sequence of activities that occur during transmission line construction and some of the measures that can be taken to mitigate potential impacts during construction.

5.10.2 Transmission

Line Construction
The transmission line construction will begin after regulatory approvals are obtained, soil conditions are established and final design is complete. The precise timing of the construction will take into account various requirements that may be in place due to permit conditions, system loading issues and available workforce.

The actual construction will follow standard construction and mitigation practices that have been developed based on past project construction experience. These best practices address right-of-way clearance, staging, erecting transmission line structures and stringing transmission lines. Construction and mitigation practices to minimize impacts will be developed based on the proposed schedule for activities, permit requirements, prohibitions, maintenance guidelines, inspection procedures, terrain, and other practices.

Environmentally sensitive areas may require special construction techniques. These may include additional erosion control measures to protect steep slopes, matting to minimize soil disturbance/compaction, and/or remediation associated with unanticipated contaminated soils.

Up to 15 to 25 construction workers will be used at any one time to construct the double circuit overhead transmission line.

Right-of-Way Restoration and Clean Up
During the construction of the transmission line, crews will attempt to limit ground disturbance wherever possible. However, areas are disturbed during the normal course of work, which can take several weeks in any one location. After construction, disturbed areas are restored to their original condition to the maximum extent practicable. Vegetation that is disturbed or removed during transmission line construction will naturally reestablish to pre-disturbance conditions. Areas with significant soil compaction and disturbance from construction activities along the proposed transmission line corridor may require assistance in reestablishing the vegetation stratum and controlling soil erosion. Commonly used methods to control soil erosion and assist in reestablishing vegetation include, but are not limited to:

- erosion control blankets with embedded seeds
- silt fences
- matting

These erosion control and vegetation establishment practices are regularly used in construction projects and long-term impacts are minimized by utilizing these construction techniques.

Substation Construction
Substation construction will begin after approvals are obtained, soil conditions are determined and the design is completed. The precise timing of construction will take into account various requirements that may be in place due to permit conditions, available workforce, and materials. Construction and mitigation practices to minimize impacts will be developed based on the proposed schedule for activities, permit requirements, prohibitions, maintenance guidelines, inspection procedures, terrain, and other practices.

5.11 Project Operation

5.11.1 Project Dispatch

The Project will be integrated into our remote dispatch control center. We expect to use the Project's unfired capability (and maximum efficiency point) for intermediate load service, dispatching it after all incrementally cheaper and "must run" units have been dispatched. The additional capacity of the Project, available through supplemental firing of the HRSG, will be utilized for peak demand periods.

5.11.2 Load Following

The Project will also serve to load follow as system load requirements change. The Project will be able to commence start up after a 30-minute notice and will have the ability to ramp at approximately 5 to 10 MW per minute depending on the pre-existing steam turbine condition.

5.11.3 Capacity Factor

The Project is expected to be dispatched 5 days per week, 16 hours per day with an initial annual capacity factor of 35%. It is expected that the capacity factor can rise to higher levels after operating for a few years.

We modeled the financial and operating impact of the Project using the Strategist computer model. Among other outcomes, the model illustrates the dispatch characteristics for the modeled system. The model shows the Project initially being utilized to support the system at a 35% capacity factor, because of the operating economics of the System and the Project's load following capability.

5.12 Project Operational Data

Operational data requirements are presented below in Table 5-3.

Table 5-3: Project Operational Information

Rule Reference	Description	Project Data
7849.0250, A(1)	Nominal Generating Capability	about 700 MW
7849.0250, A(2)	Operating Cycle	Combined Cycle
7849.0250, A(2)	Expected Annual Capacity Factor	35 percent
7849.0250, C(2)	Service Life	35 Years
7849.0250, C(3)	Estimated Average Annual Availability	> 90 percent
7849.0320, A	Estimated Land Requirements	35 acres on existing site
7849.0320, E (1)	Estimated Maximum Groundwater Pumping Rate for Site Surface Water Appropriation	250 GPM peak, 200 GPM daily average, no change from current plant 447 cfs for Project, 633 cfs for Site
7849.0320, E (2)	Estimated Annual Project Groundwater Appropriation (assuming RO purification process)	17 million gallons/year or 51 acre-feet/year (34% of site appropriation)
7849.0320, E (3)	Annual Project Surface Water Consumption	215,100 acre-feet (50% of site appropriation)

Below is Figure 5-5 that provides a preliminary artist's rendition of what the repowered facility will look like.

Figure: 5-5: Preliminary Rendering Diagram

5.13 Maintenance Requirements

5.13.1 Generation

The scope and frequency of maintenance work on the Project's combustion turbine, steam turbine, HRSG, and the balance of Plant equipment will be in accordance with power industry standards and equipment manufacturer recommendations.

The frequency of maintenance for major combustion turbine components is based on the number of unit start-ups and firing hours and falls into three categories:

- Combustor inspections typically occur every 450 starts or 12,500 firing hours and require a 6-7 day outage,
- Hot gas path inspection and component replacement occurs about every 900 starts or 25,000 firing hours requiring an 11 to 13-day outage, and

- Major overhauls are scheduled about every 1800 starts or 50,000 firing hours and require a 23 to 25 day outage.

The HRSG should require only periodic inspection and minor maintenance that can be scheduled to coincide with outages of the combustion turbine. Major overhaul of the steam turbine-generator, condenser and associated equipment will be necessary every six to eight years. Balance of plant and cooling tower equipment should only require routine maintenance.

5.13.2 Transmission

Periodic inspections, maintenance and damage repair will be performed during the life of the transmission facilities to ensure their continued integrity. Personnel on foot, snowmobile, ATV, or pick-up truck will typically perform annual inspections. If problems are found during inspection, repairs will be performed. Aerial inspections are conducted more frequently.

The right-of-way will be managed to remove vegetation that interferes with the operation and maintenance of the lines. Current practice provides for the inspection of major transmission line right of ways every five years to determine if clearing is required. Right-of-way clearing practices include a combination of mechanical and hand clearing, along with herbicide application where allowed to remove or control vegetation.

The estimated service life of the proposed transmission lines for accounting purposes is approximately 40 years. However, practically speaking, high voltage transmission lines are seldom completely retired. Transmission infrastructure has very few mechanical elements and is built to withstand weather extremes that are not normally encountered. With the exception of severe weather such as tornadoes and heavy ice storms, transmission lines rarely experience structural and/or electrical failures. Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is sensed on the system. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99%.

The principal operating and maintenance cost for transmission facilities is the cost of inspections, done every other year by ground inspection in metro areas. Annual operating and maintenance costs for transmission lines in

Minnesota and the surrounding states vary. Actual line-specific maintenance costs depend on the setting, the amount of vegetation management necessary, storm damage occurrences, structure types, materials used, and the age of the line.

Substations require a certain amount of maintenance to keep them functioning in accordance with accepted operating parameters and the National Electric Safety Code ("NESC") and North American Electric Reliability Corporation ("NERC") requirements. Transformers, circuit breakers, batteries, protective relays, and other equipment need to be serviced periodically in accordance with the manufacturer's recommendations. The substation site must be kept free of vegetation and adequate drainage must be maintained. The estimated service life of the proposed substation facilities for accounting purposes is 38 years.

5.14 Project Cost Evaluation

In our 2010 Resource Plan analysis we estimated the capital cost of the proposed facility to be approximately $600 million. Updated and more detailed cost estimates have been made and are presented in the format requested by Minnesota Rule 7849.0250 in Appendix H. These costs include the repowered plant costs, the substation, interconnecting transmission line costs and the incremental costs of a cooling tower. The Project's economic impact on the System was also evaluated using the Strategist model as described in Chapter 4. The model compared the Project to retiring the units and using simple cycle generating resources to meet demand (Alternative Generation), extending the life of the units such that they can continue to operate on coal, and replacing with a new biomass plant. The model shows the Project with the lowest overall cost of the alternatives modeled (see Table 4-1). In Chapter 4 we have included a sensitivity analysis table that demonstrates the effect of including the complete cost of a cooling tower for the entire plant site including existing Unit 5/2.

6 Environmental Information

The Project provides numerous environmental benefits as it allows for retiring aging coal-fired generation technology and replacing it with flexible, clean and efficient natural gas-fired combined cycle technology. These benefits include:

- Enabling Xcel Energy's system to operate reliably with increased wind generating capacity;
- Utilizing an established site and existing transmission to renew and expand our fleet thereby avoiding new generating sites and transmission corridors in the state;
- Taking advantage of substantial existing infrastructure available for use at the plant site, such as transmission lines, natural gas pipeline corridors, water and wastewater systems, transportation infrastructure and other facilities; and
- Reducing GHGs and other air emissions.

This section discusses the environmental impacts of the proposed Project, and provides the environmental data required under Minnesota Rule 7849.0310, 7849.0320 and 7849.0330. The environmental impacts of the alternatives to the Project are discussed in Chapter 4.

6.1 Air Impacts

6.1.1 Air Emissions

This subsection addresses the requirements of Minnesota Rule 7849.0320(D) that states an applicant shall provide "*for fossil fueled facilities:*

(1) the estimated range of trace element emissions and the maximum emissions of sulfur dioxide, nitrogen oxides, and particulates in pounds per hour during operation at rated capacity; and

(2) the estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from the stack of sulfur dioxide, nitrogen oxides, and particulates in micrograms per cubic meter during operation at rated capacity and assuming generalized worst-case meteorological conditions;"

and Minnesota Rule 7849.0330(A) states an applicant shall provide "*for overhead transmission facilities:*

(3) a discussion of ozone and nitrogen oxide emissions attributable to the transmission facility;"

Natural gas-fired combined cycle technology is among the most efficient and cleanest means of generating utility-scale electricity. Natural gas combustion generates significantly less carbon dioxide, particulate matter, sulfur dioxide, and toxic air emissions (including mercury) than oil or coal.

The primary constituents of concern resulting from combustion of natural gas are NO_x, CO and VOCs. The Project will control NO_x emissions through use of dry low-NO_x burners and SCR. Good combustion practices and oxidation catalysts will be used to control emissions of fine particulates, CO, and VOCs.

Quantities of most types of air emissions from the Project will be significantly lower than from the existing coal fired units. VOCs will be higher on an annual basis than from the coal fired units because of emissions during startup of the combined cycle units. During startup, combustion turbines must be held at a low load until the HRSG and steam turbine reach manufacturer-specified temperatures, to avoid equipment damage. Additionally, SCRs and oxidation catalysts do not control emissions efficiently until combustion gases reach a certain temperature not achieved at low loads. Preliminary estimates are that NO_x, SO_2, and Hg emissions will be reduced 96 to 99% on an annual basis, and that particulate matter and carbon dioxide emissions will be reduced 50 to 65% on an annual basis from the current units' operations. To calculate these reductions we used an annual average from a 24 month period during 2008-2010.

Emissions categories regulated by the federal Prevention of Significant Deterioration ("PSD") program will be netted against the current emissions from Units 3 and 4. Preliminary results of the netting indicate that PSD regulations will be in effect for VOCs. The main outcome of PSD will be VOC emission limits in the air emissions permit, based on a Best Available Control Technology analysis.

Table 6-1 presents the estimated air emissions from the new combined cycle units. Estimated impacts to ambient air quality summarized in Table 6-2 are based on preliminary modeling using an EPA approved dispersion model (AERMOD).

Table 6-1: Estimated Project Air Emissions

EPA Criteria Pollutants		
Pollutant	**Emission Rate** Two Units Without Duct Firing, at Rated Capacity (average ambient conditions, base load) (lbs/hour)	**Emissions**[1] Two Units With Duct Firing, at Projected Annual Operating Hours (tons/year)
SO_2	4	6
NO_X	66	132-157
PM_{10}	41	67
CO	16	85-209
VOCs	19	104

Hazardous Air Pollutants (HAPs)			
Pollutant	**Emissions**[2] Two units at Projected Annual Operating Hours (tons/year)	Pollutant	**Emissions**[2] Two units at Projected Annual Operating Hours (tons/year)
1,3-Butadiene	0.00	Hexane	0.55
1,4 Dichlorobenzene	0.00	Lead	0.00
Acetaldehyde	0.24	Manganese	0.00
Acrolein	0.04	Mercury	0.00
Arsenic	0.00	Naphthalene	0.01
Benzene	0.07	Nickel	0.00
Beryllium	0.00	Polycyclic Aromatic Hydrocarbons	0.01
Cadmium	0.00	Polycyclic Organic Matter	0.00
Chromium	0.00	Propylene Oxide	0.18
Cobalt	0.00	Selenium	0.00
Dioxins	0.00	Toluene	0.80
Ethylbenzene	0.20	Xylenes	0.39
Formaldehyde	4.43		

[1]Annual emissions from two combustion turbines, with startup and shutdown periods, at 3,066 operating hours each and HRSG duct firing at 438 hours each.
[2]Annual emissions from two combustion turbines at 3,066 operating hours each and HRSG duct firing at 438 hours each. Emissions numbers do not account for reduction in organic HAPs achieved with oxidation catalyst.

Table 6-2: Estimated Maximum Contributions to Ambient Air Quality

Pollutant	Units 3 and 4 Repowering Project Contribution to Ground-level Concentrations (µg/m^3)	National and Minnesota Ambient Standards (µg/m^3)
SO_2 (24-hour)	0.8	365
NO_2 (24-hour)	14.1	--
PM_{10} (24-hour)	6.3	150

Note: Based on two combustion turbines and duct burners, 100% loaded.

6.1.2 Transmission Air Emissions

The potential air emissions associated with the Project transmission lines are negligible. However, there is potential for ozone and nitrogen oxide due to corona. Corona consists of the breakdown or ionization of air within a few centimeters of conductors which can produce ozone and oxides of nitrogen in the air surrounding the conductor. Typically, some imperfection such as a scratch on the conductor or a water droplet is necessary to cause corona. Ozone is not only produced by corona, but also forms naturally in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus humidity or moisture, the same factors that increase corona discharges from transmission lines, inhibit the production of ozone. Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short lived. For a 345 kV transmission line, the conductor gradient surface is usually below the air breakdown level.

Currently, both state and federal governments have regulations regarding permissible concentrations of ozone and NO_2. The applicable standards for these compounds in parts per million ("ppm") are presented in Table 6-3.

Table 6-3: Applicable Ambient Air Quality Standards for Transmission Projects

Pollutant	Level	Averaging Time	National or Minnesota Standard
Nitrogen Dioxide	0.100 ppm	1-hour	National
Nitrogen Dioxide	0.053 ppm	Annual	National
Nitrogen Dioxide	0.05 ppm	Annual	Minnesota
Ozone	0.075 ppm	8-hour	National
Ozone	0.08 ppm	8-hour	Minnesota

For the overhead 345 kV/345 kV double circuit design with both circuits in service on the proposed route, the predicted ozone concentration is 0.0007 ppm in foul weather (worst case) conditions. The corona loss estimate is 0.1 W/m. These calculations were obtained from the Software Applications for the EPRI AC Transmission Line Reference Book, 200kV and Above, Third Edition.

The result is well below both federal and state standards. Most calculations of the production and concentration of ozone assume high humidity or rain, with no reduction in the amount of ozone due to oxidation or air movement.

6.1.3 Fugitive Dust

Site preparation and construction activities to include construction of the transmission lines will produce small amounts of fugitive dust from earth-moving, construction and right-of-way clearing. Fugitive emissions from earth-moving and construction will be controlled by watering or applying dust suppressants to exposed soil surfaces as necessary. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the overall emissions and dust-producing earth-moving, construction and right-of way clearing processes.

Fugitive dust emissions will not be generated in any significant amounts during operation of the Plant and will be reduced with the elimination of coal as a fuel. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the emission and dust-producing construction phases.

6.2 Noise Impacts

This subsection addresses the requirements of Minnesota Rule 7849.0320(I) which requires an applicant to provide:

"the potential sources and types of audible noise attributable to operation of the facility;"

and Minnesota Rule 7849.0330 subpart A (5) that states an applicant shall provide:

"a discussion of the characteristics and estimated maximum and typical levels of audible noise attributable to the transmission facilities;"

Generation Noise

Noise from the generating units is not expected to have a significant impact. The generating units will be in compliance with state and local noise standards. The generation is located in an isolated area with the nearest residences located more than 1,500 feet away from the Plant. Noise from the operation of the repowered units is expected to be predominantly low frequency noise, as is noise from traffic. Noise from the generation operations will not significantly impact the acoustical environment given the noise control technology that will be employed by the new generating units. In addition, existing Units 3 and 4 will be retired along with the noise associated with coal trains and other coal and ash handling processes.

To control potential generation noise impacts and meet applicable standards, the Company will potentially employ several noise mitigation measures including:

1. Totally enclosed generation building containing the major generation equipment including the combustion turbines, HRSGs, feedwater pumps and steam turbine
2. HRSG flue gas stack silencers
3. Low noise transformer packages
4. Generation Building acoustical louvers
5. Generation Building roof fan noise reduction packages
6. Combustion turbine generator air inlet silencer
7. Generation Building wall and ceiling insulation
8. Steam vent silencers
9. Diesel engine silencers

Thus, generation operation is expected to be 50 dBA at the nearest residence which meets the state noise standards established by the MPCA. Noise will be generated by the construction of the Project. Construction noise will be predominantly from intermittent sources originating from diesel engine driven construction equipment. Potential noise impacts will be mitigated by proper muffling equipment fitted to construction equipment, as well as restricting activities if necessary. Additional noise will be generated by pile driving activities. Pile driving activities are expected to last three months and to occur in the first half of 2013.

Transmission Noise

Overhead transmission conductors produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. Generally, activity-related noise levels during the operation and maintenance of substations and transmission lines are minimal.

Noise emission from a transmission line occurs during certain weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling sound due to the small amount of electricity ionizing the moist air near the wires. During heavy rain the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines can produce noise.

However, noise levels produced by a 345 kV transmission line are generally less than outdoor background levels and are therefore not typically audible. The noise generated from the transmission lines is not expected to exceed the background noise levels and would therefore not be audible at any receptor location.

6.3 Water Needs

Water usage associated with operation of the Project will be similar to that of the existing Plant, so the Project will not have a major incremental impact on water supplies. Details of expected water usage required by Minnesota Rule 7849.0320(E) are provided in Table 5-3.

Surface water appropriated from the Minnesota River is currently used for cooling water and that source will be used to supply the cooling water for the Project as well. The total surface water appropriations for the site will be within the existing MnDNR Water Appropriations Permit (#1961-0270) limitations. For once-through cooling, the withdrawal rate will be higher than in recent years but similar to operations with four steam turbines in the late 1990's. An option for closed cycle mode with a cooling tower will result in significantly lower withdrawal volumes when operating in such a mode. Moreover, when in closed cycle mode, the evaporative losses through a cooling tower are expected to be higher than through the cooling lake ponds while in the once-through mode.

The closed cycle mode is anticipated to help address the fish protection requirements of EPA's Clean Water Act Section 316(b) for existing facilities. Additionally, the use of recycled water for cooling tower makeup is under consideration. The requirements and details of implementation of the cooling water needs for the Project will be part of the NPDES Permit amendment/approval (refer to section 2.5.4). The existing Plant is currently operated with once-through cooling. As EPA is currently updating for the Section 316(b) rule, the Plant site is planning that a cooling tower will be needed to satisfy the expected rule update.

Groundwater from an existing site well will supply other water needs for the Project. No increase in the groundwater appropriation rate or annual withdrawal volume will be required for the Project. The annual withdrawal volumes for future site operations (new and existing units) are expected to be within the range of existing plant operations.

6.4 Waste Generation

Wastewater generation associated with operation of the Project will be similar to or reduced from that of the existing plant. The solid waste generation will be reduced because there will no longer be coal ash generated at the Plant.

Estimates of discharges to water and solid wastes attributable to operation of the Project, required by Minnesota Rules 7849.0320(F, G, and H), are provided in Table 6-4. All waste management activities will be conducted in accordance with applicable rules, regulations and permits.

The most significant discharge to water will be the continued discharge of cooling water to the Minnesota River. As part of the Project, a new cooling water structure for the combined cycle equipment will be constructed for discharge into Black Dog Lake.

Cooling tower operation will create the addition of cooling tower blowdown as a new discharge to surface waters or to the sanitary sewer depending on NPDES and MCES permitting. Other liquid or solid waste streams that could result from the addition of a cooling tower would be wastewater resulting from the treatment process for cooling tower make up water.

Sanitary wastewater will continue to be discharged to the existing sanitary sewer system. Other liquid wastes will stem from routine maintenance activities. No radioactive releases will occur as a result of the Project.

The Project will eliminate the annual generation of approximately 33,000 tons of coal combustion residue (coal ash) currently being generated from the operation of the existing coal-fired Units 3 and 4. Please note that approximately 78% of this material is being beneficially used as a Portland cement replacement in concrete.

As EPA is currently in the process of updating 316(b) regulations, the water discharges shown in Table 6-4 covers both once-through cooling and cooling tower surface water discharges.

Table 6-4: Liquid and Solid Wastes

Waste	Phase	Description	Generation Rate	Disposition Method
Project Cooling Water Discharge	Liquid	Once through cooling water discharge	70,000 MGPY (once through mode all year operation)	Discharge to Minnesota River via the cooling lake (Black Dog Lake) under NPDES permit
Cooling Tower Blowdown	Liquid	Cooling Tower Blowdown	521 MGPY (closed cycle mode all year operation)	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Process Water Blowdown	Liquid	HRSG Blowdown	3.6 MGPY	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Process Water Blowdown	Liquid	Evaporator Cooler Blowdown (Spring through Fall only)	0.4 MGPY at 20% capacity factor	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Roof/Yard Drain	Liquid	Surface / Building Runoff (quantity assumes complete runoff)	28.5 MGPY for 35 acres at 30 inches precipitation per year.	Discharge to surface waters under NPDES permit via settling pond.
RO Reject Water	Liquid	Water containing dissolved solids	3 MGPY	Discharge to surface waters under NPDES permit or

Waste	Phase	Description	Generation Rate	Disposition Method
		present in the raw water source except at a greater concentration.	20 gpm (max.) <0.14 mgy	discharge to sanitary sewer
Service Water	Liquid	Equipment wash water.	5.3 MGPY similar to present except during construction	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Sanitary Wastewater	Liquid	Domestic wastewater.	0.2 MGPY similar to present	Existing sewer system
Oil/Grease	Solid	Lubricants, hydraulic fluid, etc.	<20 barrels/yr	Manage used oil with a contract firm
Maintenance Materials	Solid	Oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, cleaning solvents.	<10 tons/yr	Dispose of properly as specially regulated, solid or hazardous waste and/or recycle as feasible and allowable
Cooling Tower Filter Waste	Solid	Residue from filtering cooling tower makeup water from Minnesota River	1230 tons/yr	Dispose of properly as specially regulated or solid waste or with dredge spoils
Settling Pond Accumulation	Solid	Maintenance cleaning of settled solids	500 tons/year	Dispose of properly as specially regulated or solid waste or with dredge spoils

6.5 Electric and Magnetic Fields

This subsection addresses the requirements of Minnesota Rule 7849.0330(A)(2) that states an applicant shall provide:

"a discussion of the strength and distribution of the electric field attributable to the transmission facility, including the contribution of air ions if appropriate;"

No adverse impacts from electric and magnetic fields associated with the Project transmission lines are expected.

The term electromagnetic field ("EMF") refers to electric and magnetic fields that are coupled together such as in high frequency radiating fields. For the lower frequencies associated with power lines (referred to as "extremely low frequencies" ("ELF")), EMF should be separated into electric fields ("EFs") and magnetic fields ("MFs"), measured in kilovolts per meter ("kV/m") and milligauss ("mG"), respectively. These fields are dependent on the voltage of a transmission line (EFs) and current carried by a transmission line (MFs). The intensity of the EF is proportional to the voltage of the line, and the intensity of the MF is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 hertz (cycles per second).

6.5.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/meter measured at one meter above the ground. *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota,* Docket No. ET-2/TL-08-1474, Order Granting Route Permit (*adopting* ALJ Findings of Fact, Conclusions and Recommendation at Finding 194 (April 22, 2010 and amended April 30, 2010)) (September 14, 2010).

The maximum EF, measured at one meter above ground, associated with the Project is calculated to be 4.32 kV/m. The calculated EFs for the Project are provided in Table 6-5.

Table 6-5: Calculated Electric Fields (KV/M) For Proposed 345 KV Transmission Line Designs (One meter above ground)

Structure Type	Maximum Operating Voltage (kV)	Distance to Proposed Centerline										
		-300'	-200'	-100'	-50'	-25	0'	25	50'	100'	200'	300'
345Kv Steel Pole Double Circuit Suspension Type	362	0.09	0.20	0.76	3.60	4.02	4.32	4.02	3.60	0.76	0.20	0.09

6.5.2 Magnetic Fields

There are presently no Minnesota regulations pertaining to MF exposure. The MF profiles around the proposed transmission line structures and conductor configuration proposed for the Project are shown in Table 6-6. MFs are calculated for the Project under two system conditions: the expected peak and average current flows as projected for the year 2015. The peak MF values are calculated at a point directly under the transmission line and where the conductor is closest to the ground. The same method is used to calculate the MF at the edge of the right-of-way. The calculated MFs show that fields decrease rapidly as the distance from the centerline increases (proportional to the inverse square of the distance from source).

The MF produced by the transmission line is dependent on the current flowing on its conductors. Therefore, the actual MFs when the Project is placed in service are typically less than shown in Table 6-6. This is because the table represents the MF with current flow at expected normal peak based on projected regional load growth through 2015, the maximum load projection timeline available. Actual current flow on the line will vary with system conditions, so MFs would be less than peak levels during most hours of the year.

Table 6-6: Calculated Magnetic Flux density (milligauss) for Proposed 345 kV Transmission Line Design (One meter above ground)

Segment	System Condition	Current (Amps)	Distance to Proposed Centerline										
			-300'	-200'	-100'	-50'	-25	0'	25	50'	100'	200'	300'
345kV Steel Pole Double Circuit Suspension Type BDS-IVH& BDS-BLL	Peak	787/336	1.83	4.03	14.59	40.42	68.23	96.62	109.96	76.27	24.10	5.70	2.46
	Average	472/202	1.10	2.42	8.76	24.28	40.97	57.98	65.96	45.75	14.46	3.42	1.48

Considerable research has been conducted throughout the past three decades to determine whether exposure to power-frequency (60 hertz) MFs causes biological responses and health effects. Epidemiological and toxicological studies have shown no statistically significant association or weak associations between MF exposure and health risks. The possible impact of exposure to EMFs upon human health has also been investigated by public health professionals for the past several decades. While the general consensus is that EFs pose no risk to humans, the question of whether exposure to MFs can cause biological responses or health effects continues to be debated.

In 1999, the National Institute of Environmental Health Sciences ("NIEHS") issued its final report on "Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields" in response to the Energy Policy Act of 1992. The NIEHS concluded that the scientific evidence linking MF exposure with health risks is weak and that this finding does not warrant aggressive regulatory concern. However, because of the weak scientific evidence that supports some association between MFs and health effects, passive regulatory action, such as providing public education on reducing exposures, is warranted.

In 2007, the World Health Organization ("WHO") concluded a review of the health implications of electromagnetic fields. In this report, WHO stated:

> Uncertainties in the hazard assessment [of epidemiological studies] include the role that control selection bias and exposure misclassification might have on the observed relationship between magnetic fields and childhood leukemia. In addition, virtually all of the laboratory evidence and the mechanistic evidence fail to support a relationship between low-level [extremely low frequency] magnetic fields and changes in biological function or disease status. Thus, on balance, the evidence is not strong enough to be considered causal, but sufficiently strong to remain a concern. (WHO, 2007 at p. 12).

Also, regarding disease outcomes, aside from childhood leukemia, WHO stated:

> A number of other diseases have been investigated for possible association with ELF magnetic field exposure. These include cancers in children and adults, depression suicide, reproductive dysfunction, developmental disorders, immunological modifications and neurological disease. The scientific evidence supporting a linkage between ELF magnetic fields and any of these diseases is much weaker than for childhood leukemia and in some cases (for example, for cardiovascular disease or breast cancer) the evidence is sufficient to give confidence that magnetic fields do not cause the disease. (*Id.* at p. 12.)

Furthermore, in its "Summary and Recommendations for Further Study" WHO emphasized that: "The limit values in [ELF-MF] exposure guidelines [should not] be reduced to some arbitrary level in the name of precaution. Such practice undermines the scientific foundation on which the limits are based and is likely to be an expensive and not necessarily effective way of providing protection." (*Id.* at p. 12).

Although WHO recognized epidemiological studies indicate an association on the range of three to four mG, WHO did not recommend these levels as an exposure limit but instead provided: "The best source of guidance for both exposure levels and the principles of scientific review are international guidelines." *Id.* at pp. 12- 13. The international guidelines referred to by WHO are the International Commission on Non-Ionizing Radiation Protection ("ICNIRP") and the Institute of Electrical and Electronic Engineers ("IEEE") exposure limit guidelines to protect against acute effects. *Id.* at p. 12. The ICNIRP-1998 continuous general public exposure guideline is 833 mG and the IEEE continuous general public exposure guideline in 9,040 mG. In addition, WHO determined that "the evidence for a casual relationship [between ELF-MF and childhood leukemia] is limited, therefore exposure limits based on epidemiological evidence is not recommended, but some precautionary measures are warranted." *Id.* at 355-56.

WHO concluded that:

> given the weakness of the evidence for a link between exposure to ELF magnetic fields and childhood leukemia, and the limited impact on public health, the benefits of exposure reduction on health are unclear and thus, the costs of precautionary measures should be very low… Provided that the health, social and economic benefits of electric power are not compromised, implementing very low-cost precautionary procedures to reduce exposure is reasonable and warranted. (*Id.* at p. 372).

Wisconsin, Minnesota, and California have all conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group ("Working Group") to evaluate the body of research and develop policy recommendations to protect the public health from any potential problems resulting from HVTL EMF effects. The Working Group consisted of staff from various state agencies and published its findings in a

White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options in September 2002, (Minnesota Department of Health, 2002). The report summarized the findings of the Working Group as follows:

> Research on the health effects of [MF] has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to [MF] and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between [MF] and health effects; however, many of them also concluded that there is insufficient evidence to prove that [MF] exposure is safe. (*Id.* at p. 1.)

The Public Service Commission of Wisconsin ("PSCW") has periodically reviewed the science on MFs since 1989 and held hearings to consider the topic of MF and human health effects. The most recent hearings on MF were held in July 1998. In January 2008, the PSC published a fact sheet regarding MFs. In this fact sheet the PSC noted that:

> Many scientists believe the potential for health risks for exposure to [MFs] is very small. This is supported, in part, by weak epidemiological evidence and the lack of a plausible biological mechanism that explains how exposure to [MFs] could cause disease. The [MFs] produced by electricity are weak and do not have enough energy to break chemical bonds or to cause mutations in DNA. Without a mechanism, scientists have no idea what kind of exposure, if any, might be harmful. In addition, whole animal studies investigating long-term exposure to power frequency [MF] have shown no connection between exposure and cancer of any kind. (PSC, 2008).

The Commission, based on the Working Group and World Health Organization findings, has repeatedly found that "there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects." *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E-002/TL-07-1407, Findings of Fact, Conclusions of Law and Order Issuing a Route Permit to Xcel Energy for the Lake Yankton to Marshall Transmission Project at p. 7-8 (Aug. 29, 2008); *See also*, *In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET-2, E015/TL-06-1624, Findings of Fact, Conclusions of Law and Order Issuing a Route Permit to Minnesota Power and Great River Energy for the Tower Transmission Line Project and Associated Facilities at p. 23 (Aug. 1, 2007)("Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.").

The Commission again confirmed its conclusion regarding health effects and MFs in the Brookings County – Hampton 345 kV Route Permit proceeding ("Brookings Project"). In the Brookings Project Route Permit proceeding, Applicants Great River Energy and Xcel Energy and one of the intervening parties provided expert evidence on the potential impacts of electric and magnetic fields on human health. The Administrative Law Judge in that proceeding evaluated written submissions and a day-and-half of testimony from these two expert witnesses. The Administrative Law Judge concluded: "there is no demonstrated impact on human health and safety that is not adequately addressed by the existing State standards for [EF or MF] exposure." *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08-1474, ALJ Findings of Fact, Conclusions and Recommendation at Finding 216 (April 22, 2010 and amended April 30, 2010).

The Commission adopted this finding on July 15, 2010. *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08- 1474, Order Granting Route Permit (September 14, 2010).

6.6 Stray Voltage

"Stray voltage" is a condition that can occur on the electric service entrances to structures from distribution lines, not transmission lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors.

Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. Transmission lines, however, can induce stray voltage on a distribution circuit that is parallel to and immediately under the transmission line. Stray voltage issues are not anticipated for the Project.

If stray voltage issues arise as a result of the construction of the Project, the Project will take appropriate measures to address potential stray voltage issues on a case-by-case basis.

6.7 Vehicle Use and Metal Buildings Near Power Lines

Passenger vehicles and trucks may be safely used under and near power lines. Due to the location of these lines, there will be minimal vehicle traffic near the lines. However, as with all power lines built by the Company, these lines will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields and grazing lands specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

Buildings are permitted near transmission lines but are generally discouraged within the right-of-way itself because a structure under a line may interfere with safe operation of the transmission facilities. Due to the location of the lines, we do not anticipate any buildings other than the Plant will be located near the transmission lines.

6.8 Radio and Television Interference

This subsection addresses the requirements of Minnesota Rule 7849.0330(A)(4) that states an applicant shall provide:

"a discussion of radio and television interference attributable to the transmission facility;"

The Project is not expected to cause radio and television interference. Corona from transmission line conductors can generate electromagnetic "noise" at the same frequencies that radio and television signals are transmitted. This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio and television signal. Tightening loose hardware on the transmission line usually resolves the problem.

If radio interference from transmission line corona does occur, satisfactory reception from AM radio stations previously providing good reception can be restored by appropriate modification of (or addition to) the receiving antenna system. AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly within the right-of-way to either side.

FM radio receivers usually do not pick up interference from transmission lines because corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz) and the excellent interference rejection properties inherent in FM radio systems make them virtually immune to amplitude type disturbances.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure (such as a steel tower) may experience interference because of signal-blocking effects. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by the mobile unit adjacent to a metallic tower.

Television interference is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect. Loose and/or damaged hardware may also cause television interference. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception is presently obtained, the Company will inspect and repair any loose or damaged hardware in the transmission line, or take other necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

6.9 Land Requirements

This subsection addresses the requirements of Minnesota Rule 7849.0320(A) that states an applicant shall provide:

"the estimated range of land requirements for the facility with a discussion of assumptions on land requirements for water storage, cooling systems, and solid waste storage;"

Total land area required for the Project, including the cooling tower, substation and transmission interconnection is approximately 35 acres (see Figure 5-3). The Project will be entirely on land already used for electric power production. Most of the site will be protected to the 100 year flood elevation level and additional protection will be provided by final grades and equipment elevations. Although protected, the area has a floodplain designation which will be addressed in the Site Permit application based on previous modeling (HEC/RAZ) work. The Black Dog Repowering Project and new switch yard will be located in areas at the Plant site currently used for coal storage and ash ponds. The proposed transmission line taps will be located on either side of the existing Xcel Energy railroad spur and service road that enters into the Black Dog Plant from the south. The transmission lines will then turn east following the north shoreline of Black Dog Lake into the new Project substation.

On site water storage will include three tanks for storage of raw and treated water for use in the HRSG's, evaporative cooling and other processes. Aqueous ammonia storage tank(s) will be added to the site for air emission NO_x reduction. No solid waste will be permanently stored on site. Temporary storage of minor quantities of oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, industrial wastes, universal wastes and hazardous wastes will occur during operation of the Project. As is the case with other similar facilities, the Project is expected to be a very small quantity generator ("VSQG") of hazardous waste.

6.10 Vegetation and Wildlife

The Project is located within the Minnesota and Northeast Iowa Morainal Section (222M), a section within the biogeographic province known as the Eastern Broadleaf Forest Province under the Ecological Classification System ("ECS") developed by the MnDNR and the U.S. Forest Service (MnDNR, 2009). The Project is further located on the border of the Anoka Sand Plain and the St. Paul Baldwin Plains and Moraines subsections of the Minnesota and Northeast Iowa Morainal Section. The Project site is primarily surrounded by wetland and riparian habitat and provides habitat for many species of plants and animals.

6.10.1 Wildlife

Wildlife commonly found near the Plant site includes a variety of small to medium sized mammals, reptiles and amphibians, birds, and fish. The largest mammal typically found in the area is the white-tailed deer. Other mammals include coyotes, fox, raccoons, beaver, opossum, woodchucks, squirrels, and muskrats. Reptiles near the Plant site include Snapping turtles, Map turtles, Softshell turtles, Painted turtles, gopher snakes, fox snakes, and northern water snakes. Amphibians include leopard frogs, pickerel frogs, spring peeper, and American toads. Fish species vary depending on the type of water body. The most commonly distributed fish species in the area include largemouth bass, sunfish, crappies, northern pike and multiple species of rough fish such as carp and suckers. Bird species include eagles, turkeys, hawks, pheasants, ducks, herons, and multiple species of song birds.

Because the Plant is located within an urban area, the fauna generally present are adapted to high levels of anthropogenic disturbance. Further, the existing Black Dog Plant provides little to no habitat for wildlife species. Therefore, it is unlikely that the construction, operation, and maintenance of the Project would have an effect on fauna present in the area. Wildlife that inhabit trees that may be removed for the transmission lines will likely be temporarily displaced. Comparable habitat is near the route, and it is likely that these organisms would only be displaced a short distance.

Raptors, waterfowl, and other bird species may be affected by the construction and placement of the transmission lines. Avian collisions are a possibility after the completion of the transmission line in areas where there are wetlands and open water. The nearest open water is Black Dog Lake, which is part of the overall Plant site.

Additionally, the electrocution of large birds, such as raptors, can be a concern with transmission lines. Electrocution occurs when birds with large wingspans come in contact with two conductors or a conductor and a grounding device. The conductors on the proposed transmission lines will be designed to be located in a horizontal configuration instead of a vertical configuration. This design will help mitigate potential avian collisions with the conductors. Additional mitigation measures will be designed in the placement of the transmission lines. Instead of crossing Black Dog Lake directly south of the proposed substation, the lines will be placed along the road between the protective cover of trees. Swan Flight Diverters ("SFDs") will be placed on the overhead static lines of the transmission line.

6.10.2 Vegetation Cover

Historically, this area was primarily floodplain and terrace forests of silver maple, cottonwood, box-elder, green ash and elm within and along the terrace forests river valley (MnDNR, 2011). Wetland complexes associated with the Minnesota River Valley system are present throughout the area. Many of the native species remain although many wetlands are dominated by invasive species such as reed canary grass or purple loose-strife.

Because the Project will be constructed within the existing Plant footprint and adjacent to an existing, active railroad line, as well as within an area populated by transmission lines and structures, the Project impacts to vegetation will be minor. The only impact will be a number of trees that will be removed along the proposed transmission line route.

6.10.3 Threatened and Endangered Species

U.S. Fish and Wildlife Service
The U.S. Fish and Wildlife Service's ("FWS's") website was reviewed for a list of species covered under the Endangered Species Act ("ESA") that may be present within Dakota County. According to the website, the following two federally listed species are known to occur within the county: Higgins eye pearlymussel (*Lampsilis higginsii*) and prairie bush-clover (*Lespedeza leptostachya*).

The Higgins eye pearlymussel is listed as endangered and occurs only within the Mississippi River and the lower portion of some of its larger tributaries. The Project will not be located at the Mississippi River. Therefore, it was determined that the Project will have no effect on the Higgins eye pearly mussel or its habitats.

The prairie bush-clover is listed as threatened and occurs within native dry mesic-prairies where the soils are well-drained with high sand or gravel content. The Project is confined to an existing Plant site and along an existing active railroad corridor that is surrounded by a very large wetland complex where only poorly-drained soils exist. Therefore, it has been determined the Project will have no effect on the prairie bush-clover or its habitat.

State of Minnesota
A request for a MnDNR Natural Heritage Information System ("NHIS") search and comments regarding rare species and natural communities for the Project Area was submitted to the MnDNR on January 11, 2011. The MnDNR responded in a letter dated March 8, 2011. The results of the MnDNR Natural Heritage Database search and MnDNR response letter are included in Appendix F.

6.11 Human Settlement

In prehistoric and the early historic periods, the bluffs above the river were the preferred location for settlement. Human groups utilized the resources in the bottomlands and wetlands, but they did not spend significant time or routinely leave behind evidence of their presence there (Merjent, Inc. 2010. Phase 1a Literature Review for the Xcel Energy Proposed Black Dog Repower Project, Dakota County, Minnesota. December 30, 2010). Today, the study area is almost entirely limited to industrial infrastructure.

The closest structure to the proposed transmission line's termination and connection with the existing 345 kV transmission lines is a residence 750 feet south of this point.

According to U.S. Census Bureau data and as shown in Table 6-7, minority groups in the area constitute only a small percentage of the total population, averaging 11.8%. Per capita incomes within the county and nearest cities to the Plant site are higher than the State of Minnesota. The percentage of persons living below the poverty level in the area is approximately 50% less than the State average. The area does not contain disproportionately high minority populations, low-income populations, or high percentages of persons living below the poverty level.

Table 6-7: Population and Economic Characteristics

Location	Population	Minority Population (Percent)	Caucasian Population (Percent)	Per Capita Income	Percentage of Individuals Below Poverty Level
State of Minnesota	5,303,925[a] (2010)	11.4 (2009)[b]	88.6 (2009)[b]	$23,198 (1999)[b]	9.6 (2008)[b]
Dakota County [c]	396,500 (2009)	11.4 (2009)	88.6 (2009)	$27,008 (1999)	4.6 (2008)
City of Burnsville	59,135 (2009)[d]	12.5 (2000)[e]	87.5 (2000)[e]	$27,098 (1999)[e]	5.1 (1999)[e]
City of Eagan	64,186 (2009)[f]	12.0 (2000)[g]	88.0 (2000)[g]	$30,167 (1999)[g]	2.9 (1999)[g]

Sources:

a U.S. Census Bureau. 2010 U.S. Census, Resident Population Data, Population Density. http://2010.census.gov/2010census/data/apportionment-dens-text.php

b U.S. Census Bureau. State and County QuickFacts. Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27000.html. Accessed December 2010.

c U.S. Census Bureau. State and County QuickFacts. Dakota County, Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27/27037.html. Accessed December 2010.

e U.S. Census Bureau. State and County QuickFacts. City of Burnsville. Available online at http://quickfacts.census.gov/qfd/states/27/2708794.html. Accessed December 2010.

d U.S. Census Bureau. Population Finder. Burnsville City, Minnesota. Available online at http://factfinder.census.gov/servlet/SAFFPopulation?_event=Search&geo_id=05000US27037&_geoContext=01000US%7C04000US27%7C05000US27037&_street=&_county=Burnsville&_cityTown=Burnsville&_state=04000US27&_zip=&_lang=en&_sse=on&ActiveGeoDiv=geoSelect&_useEV=&pctxt=fph&pgsl=050&_submenuId=population_0&ds_name=null&_ci_nbr=null&qr_name=null&reg=null%3Anull&_keyword=&_industry=. Accessed December 2010.

f U.S. Census Bureau. Population Finder. Eagan City, Minnesota. Available online at http://factfinder.census.gov/servlet/SAFFPopulation?_event=Search&geo_id=16000US2708794&_geoContext=01000US%7C04000US27%7C16000US2708794&_street=&_county=Eagan&_cityTown=Eagan&_state=04000US27&_zip=&_lang=en&_sse=on&ActiveGeoDiv=geoSelect&_useEV=&pctxt=fph&pgsl=160&_submenuId=population_0&ds_name=null&_ci_nbr=null&qr_name=null&reg=null%3Anull&_keyword=&_industry=. Accessed December 2010.

g U.S. Census Bureau. State and County QuickFacts. City of Eagan. Available online at http://quickfacts.census.gov/qfd/states/27/2717288.html. Accessed December 2010.

The Project is not located in an agricultural area. Based on recent aerial photographs, the nearest significant tracts of land with evidence of agriculture are south of the City of Apple Valley, approximately 6 miles from the Project.

There are no forested areas where species are harvested within the Plant boundaries. The primary tree cover in the area is associated with waterways and along the Xcel Energy railroad spur. No economically significant forestry resources are located along the proposed new transmission lines route.

The Minneapolis – St. Paul International Airport ("MSP") is located approximately 3.3 miles north of the property boundaries. According to the Standards for Determining Obstructions, proposed structures within the three mile radius of an airfield cannot exceed 200 feet in height. The proposed transmission lines will not be located within three linear miles of the MSP and are therefore not subject to Federal Aviation Administration ("FAA") requirements defining airfield obstructions (14 C.F.R. 77).

According to the Minnesota Department of Transportation, county pit map for Dakota County and USGS topographic maps, there are no gravel pits, rock quarries, or commercial aggregate sources in the vicinity of the Plant boundaries.
http://www.dot.state.mn.us/materials/maps/copitmaps/dakota.pdf.
Because no existing gravel and rock resources are being utilized within the area, no impacts are anticipated. Unknown resources that may exist in the area would be situated in close proximity to existing utility and roadway rights-of-way, making development unlikely.

6.12 Archeological and Historic Resources

In December 2010, a review of records at the Minnesota State Historic Preservation Office ("SHPO") identified two archaeological sites and one inventoried historic architectural property located within one mile of the Plant site. A summary of the inventoried cultural resource sites is provided in Table 6-8.

Table 6-8: Previously Identified Historic Properties Near the Plant Site

Type of Historic Property	Inventory Number	Description	NRHP Status
Archaeological	21HE0012	Contact Period mound site	unevaluated
Archaeological	21DK0041	Prehistoric Arvilla Complex mound site (destroyed)	N/A
Architectural	N/A	Union Pacific Railroad	Potentially eligible

Both of the archaeological sites are mound sites, confirmed as burials by excavation. Site 21DK0041, which was dated to the prehistoric Arvilla Complex (AD 500-900), was completely destroyed by development in the 1960s. Site 21HE0012 was first recorded in the 1890s as a mound site containing 36 mounds. In the 1930s a University of Minnesota student excavated Mound 21 of the site and discovered historic burials dating to the well documented period of Dakota occupation of the Minnesota River Valley. The current condition of this site is unknown. As an unplatted burial, this site is subject to the Minnesota Private Cemeteries Act (Minnesota Statutes Chapter 307), and comes under the jurisdiction of the Office of the State Archaeologist. As a Native American burial ground, the site would also come under the jurisdiction of the Minnesota Indian Affairs Council.

Site 21DK0041 has been destroyed. Site 21HE0012 is located on the river bluff more than one-half mile north of the Plant boundaries. Since both sites are located outside the construction footprint and outside the 150-feet-wide transmission line rights-of-way, they will not experience direct impacts resulting from the construction of this Project.

The only historic architectural property within one mile of the Plant boundaries is the Union Pacific Railroad, which runs along the southern edge of the Minnesota River Valley. This rail line between St. Paul and Mankato, first built in 1864, represents the early expansion of Minnesota and the transportation network that helped bring the state's agricultural products to the marketplace. A Multiple Property Nomination to the NRHP for Railroads in Minnesota 1862-56 (Schmidt et al., 2002) establishes the criteria for NRHP eligibility for railroad properties. Although the Union Pacific Railroad is not specified as eligible for listing on the NRHP, it does meet the criteria and should be considered potentially eligible.

The Union Pacific Railroad is on the southern edge of the transmission line construction footprint, but will not be directly impacted by proposed construction. Further, the Project will be constructed within the existing plant boundaries and the transmission line construction will occur along an artificial berm built to support the railroad spur from the Union Pacific line to the Plant. The proposed construction is in keeping with the industrial use and development of the location. The proposed construction will constitute an in-kind expansion of the existing built environment and will not create new indirect visual impacts.

On behalf of Xcel Energy, Merjent, Inc. provided a copy of the Phase 1a literature review report discussing its findings and recommendation that no archaeological or historic resources would be affected by construction or operation of the new facility and transmission lines on January 15, 2011. In its letter dated February 15, 2011, the Minnesota SHPO concluded that, based on its review of the Project information, there are no properties listed on the State or NRHP and no known or suspected archaeological properties in the area that would be affected by the Project (see Appendix G).

6.13 Traffic and Transportation Infrastructure

This subsection addresses the requirements of Minnesota Rule 7849.0320(B) that states an applicant shall provide:

"the estimated amount of vehicular, rail, and barge traffic generated by construction and operation of the facility;"

During construction of the Project, there will be an increase in traffic on the roadways into the Plant. Site fill activities will require approximately 30,000 trucks for delivery of material. Minor temporary road upgrades may be necessary to facilitate delivery of equipment and materials for the Project. Some equipment and materials for construction of the Project will be delivered by rail. During construction, barge delivery is also an option but is not anticipated to be significant. Operation of the Project will result in a decrease in traffic from current traffic levels. The existing roads and rail yard will meet the Project access needs during future operations. The delivery of coal to the Plant, which has historical been by rail, will cease as a result of the Project.

6.14 Work Force Requirements

This subsection addresses the requirements of Minnesota Rule 7849.0320(J) which required an applicant to provide:

"the estimated work force required for construction and operation of the facility;"

An estimated 300 construction jobs will be created during the equipment installation phase of the Project, adding over $30 million of payroll into the economy. Operation of the repowered units after the Project construction will require approximately 15 full-time positions.

7 Project Benefits Society

This Project benefits society by allowing the Company to meet our customers' energy needs in an economically and environmentally responsible manner, thereby supporting future development in Minnesota and the region.

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minn. R. 7849.0120). This section addresses the third criterion which states that:

"by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a matter compatible with protecting the natural and socioeconomic environments, including human health."

7.1 Society Benefits from Reliable and Low Cost Electricity Sources

Minnesota law establishes parameters to ensure that utilities select and implement resources that provide reliable energy at reasonable prices and with minimal impact on the environment. Our peak demand and energy requirements are growing at an average of 1.1% and 0.9%, respectively per year.[6] We have a statutory obligation under Minnesota Statutes Section 216B.04 to plan our system to reliably serve our customers.

A cost effective, reliable energy supply is an economic driver for our customers as well as state and regional economies. Our diverse energy portfolio provides customers with a reliable and economical electrical energy supply. This Project will complement our electric generation resources by providing needed intermediate and peaking capacity and utilizes existing facilities to provide reliable, cost effective energy to meet our customers' needs in a more environmentally sound manner.

We will be adding significant amounts of additional wind generation to our system to meet the renewable targets of the jurisdictions in which we operate. The addition of wind resources requires other resources that can ramp quickly to meet customers' needs when the wind resources are unavailable due to the lack of appropriate wind speeds. Having quick ramp rate resources will help

[6] These estimates are based on 50 percentile energy forecast and 90 percentile net demand forecast.

the Company better integrate wind generation into our system due to the variability in wind generation.

This Project also increases system reliability due to its close proximity to a large load center, the Twin Cities Metropolitan area. This Project provides additional capacity close to load that can economically generate more energy for the load center with less energy lost during transmission.

The Project also adds a basically new natural gas resource to our generation portfolio. Natural gas-fired generation is among the most reliable technologies to meet intermediate and peaking needs. While natural gas based generating capacity is increased, actual use of natural gas to produce electric energy increases only modestly. The addition of the Project allows us to better utilize base load resources elsewhere on the system.

7.2 Provides Value to Customers

This Project is a cost-effective means of providing needed capacity on short notice. The Project increases system efficiencies by being able to meet both increasing intermediate and peaking needs at an existing generation facility site. The use of an existing Plant site also allows for better utilization of existing off-site transmission infrastructure. This Project is a cost-effective, lower GHG emitting resource than alternatives. Additionally, this Project helps offset the intermittency of the significant amount of new wind resources that are being added to our system. Lastly, the Project provides a hedge against future environmental regulations. Considered together, this cost-effective lower emissions resource provides great value – economic and environmental – to customers.

7.3 Efficiently Uses Existing Plant Site

This Plant site already contains existing gas-fired generation and the space necessary to add additional gas-fired generation. The site footprint will not be expanded and no greenfields will be affected by the Project. The Project requires only minimum additional transmission facilities to transport electricity from the Plant to the electrical grid. The Project will also take advantage of existing gas pipelines into the Twin Cities area, rail and road transportation, water supply and wastewater infrastructure. It is also possible that some of the new high-pressure gas pipeline can be sited within the current pipeline right of way.

7.4 Best Fit to Existing Transmission Facilities

Only short new transmission line interconnections to the existing metropolitan Twin Cities beltway transmission system are required to accommodate the increase in generating capacity at the Plant site. Based upon preliminary analysis, bulk system reliability is maintained (adequacy and security) without major degradation in transmission system performance, thereby rendering this a highly preferred site. The Black Dog Plant has the transmission rights necessary to deliver the combined output of the Plant to customers.

7.5 Results in Lower Emissions

The Project will generate the least air emissions and the least impact to air quality of all feasible alternatives to meet the Project objectives. The Project will result in significantly less CO_2 being emitted to the atmosphere as compared to the alternatives. The specific comparisons of emissions of the alternatives are shown in Table 4-4 and as discussed in Section 4.4.9, demonstrate that the Project has lower air emissions when compared directly to alternatives.

7.6 Creates Jobs

The Project will employ an estimated 300 construction workers over the Project construction period. These high-skilled, high-paying positions will add payroll dollars into the local economy. When complete, the Project will employ a highly skilled and dedicated work force to operate and maintain the new units. This work force not only benefits the Plant but also the entire community as active, involved, tax paying citizens participating and contributing to the greater social fabric of the community.

7.7 Supports Future Economic Development

Historically, we have maintained low electric rates relative to utilities in other regions of the United States. As a result, Minnesota and the region have been able to attract industrial concerns and maintain steady economic growth. This Project will allow us to continue to reliably serve our customers' energy needs while maintaining favorable rates to support future economic development in Minnesota and the surrounding states. The Project was the most cost-effective alternative—even when a wide variety of sensitivities were considered.

7.8 Provides Tax Benefits

It is anticipated that the Project will continue to provide local, state and federal tax benefits. It is estimated that the local property tax benefits due to the Project will result in an additional $2 million annually.

8 Project Complies with Rules and Policies

This Project serves the overall state energy needs, fosters state energy policy, and complies with all applicable rules and regulations.

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minn. R. 7849.0120). This section addresses the fourth criterion, which provides that:

"the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments."

8.1 Project is Consistent with Minnesota Energy Policy

8.1.1 Legislative Preference

The Minnesota legislature has determined that:

"The following energy sources for generating electric power distributed in the state, listed in their descending order of preference, based on minimizing long-term negative environmental, social, and economic burdens imposed by the specific energy sources are:

1. *wind and solar;*
2. *biomass and low-head or refurbished hydropower,*
3. *decomposition gases produced by solid waste management facilities, natural gas-fired cogeneration, and waste materials or byproducts combined with natural gas;*
4. *natural gas, hydropower that is not low-head or refurbished hydropower, and solid waste as a direct fuel or refuse-derived fuel; and*
5. *coal and nuclear power."*[7]

Xcel Energy supports an energy policy that balances the impact of energy use and production on the environment with the costs and reliability of various resource options. We believe a diverse portfolio that includes renewable resources and DSM best meets this objective. The selection of this Project

[7] Minn. Stat. § 216C.051, subd. 7(c) and (d).

over the alternatives considered is consistent with the State's Energy Policy priorities.

First, we continue our dedication to achieving high levels of DSM savings. In our most recent Triennial CIP filing, we committed to achieve savings of 1.15% of gross annual retail sales in 2010, 1.2% in 2011, and 1.3% in 2012. We propose to fully implement our 1.3% savings goal, and work toward meeting the state goal of 1.5% savings over the next several years as outlined in the Next Generation Energy Act of 2007. And, in fact our preliminary results for 2010 indicate that we achieved a 1.5% savings goal, or over 400 GWhs in savings.

Second, we are on target to comply with the nation's most aggressive renewable energy standard. If we desire to meet this goal on a levelized basis, we will need to add approximately 100 MW of wind to our system per year for the foreseeable future. As result of our DSM and RES requirements, we did not look at adding additional wind or energy efficiency savings in lieu of a resource.

We compared this project to the following alternatives:

- investing in the life extension and environmental control retrofits necessary to continue to operate Units 3 and 4 on coal,
- ceasing the operation of Units 3 and 4 and constructing about 700 MW of combined cycle generation at the Black Dog Generating Plant site,
- adding necessary resources elsewhere on the Company's system and ceasing the operation of Units 3 and 4, and
- a biomass alternative.

Of these alternatives, the Black Dog Repowering Project is the most cost effective project, results in the greatest system CO_2 emissions reductions of the alternatives, and results in the fewest environmental impacts. The Project involves modification to an existing site to generate lower emission energy and minimizes "*negative environmental, social and economic burdens…*" when compared to the alternatives considered.

The 2007 Legislature declared the state's goal to reduce statewide GHG emissions across all sectors producing those emissions to a level at least 15% below 2005 levels by 2015, to a level at least 30% below 2005 levels by 2025, and to a level at least 80% below 2005 levels by 2050. (Minn. Stat. § 216H.02, subdivision 1.) The modeling supporting our 2010 Resource Plan, which includes this Project, suggests that implementation of the 2010 Resource Plan will ensure our compliance with the state's GHG reduction milestones, providing a 25% reduction in CO_2 emissions from 2005 levels by 2020.

8.1.2 State Energy Policy

This Project serves the State Energy Policy goals as stated in the Office of Energy Security's publication *Energy Policy and Conservation Report 2008*. The four guiding principles of Minnesota energy policy are to ensure that:

1. *Minnesota has a reliable energy-provision system into the future;*
2. *the state's energy system meets Minnesota's economic needs;*
3. *Minnesota's energy costs are reasonable priced; and*
4. *the environmental impacts of energy produced and consumed in the state are reduced.*

The "continuing reliability and quality of electric service is one of the guiding principles of Minnesota's energy policy and is among the OES's top priorities in the coming years. Accordingly, the OES, in concert with other state agencies and interested persons, seeks to preserve and enhance the reliability and quality of the electric system in Minnesota."[8]

This Project clearly addresses all four of these guiding principles by offering a reliable, reasonably priced, and environmentally friendly generation option to meet our customer's needs. More importantly, because the focus of the OES's priorities is reliability, this Project better meets this emphasis than any of the other alternatives considered. In addition to providing increased system reliability by being able to respond to the fluctuations of wind resources, by being located close to a major load center, this Project also enhances the overall reliability of the transmission system.

8.1.3 Non-Proliferation Policy

This Project will take full advantage of existing infrastructure by being constructed at an existing generation facility and using existing high-voltage electric transmission facilities to transport the energy generated. The use of

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[8] Page 17, *Energy Policy and Conservation Report 2008*, Office of Energy Security

existing transmission facilities is consistent with the State of Minnesota's commitment to non-proliferation of transmission corridors.[9]

8.2 The Project Complies with Federal and State Environmental Regulations

The Project meets or exceeds the requirements of all applicable federal and state environmental laws and regulations. Chapter 2 provides a list of permits and approvals the Project must obtain from government entities in support of full compliance.

8.3 Carbon Risk Analysis Compliance

Order Point 16 of the Commission's Order dated July 28, 2006 from our 2004 Resource Plan (Docket No. E002/RP-04-1752), states:

Xcel shall discuss carbon risk analysis strategies in the November 1, 2006 base load certificate of need filing required in paragraph 10, in its next resource plan, in future certificate of need filings, and in other proceedings involving the acquisition of generation resources.

There is significant concern over climate change policy—internationally, nationally and at the state level. The contribution of carbon released during the combustion of fossil fuels for electric generation is often at the forefront of that discussion. There has been a significant amount of discussion regarding the development of a market for trading carbon credits. This, and the potential for the regulation of other emissions, creates a potential regulatory and cost risk when proposing to construct a fossil fuel burning power plant that emits carbon dioxide.

This Project reduces carbon dioxide emissions from those currently found at this site and therefore reduces the cost risk associated with potential future carbon regulation. Additional analysis of risks associated with the Project that are driven by carbon regulation uncertainty is provided in Chapter 3 with sensitivity analyses provided in Chapter 4.

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[9] *People for Environmental Enlightenment and Responsibility (PEER) v. Minnesota Environmental Quality Council*, 266 N.W. 2d 858 (Minn. 1978)

CERTIFICATE OF SERVICE

I, Mark Suel hereby certify that I have this day served copies of the foregoing document on the attached list of persons electronically, delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

DOCKET NO. E002/CN-11-184

Dated this 15th day of March, 2011

/s/

Mark Suel

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Approximately 450 MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project

ISSUE DATE: May 25, 2011

DOCKET NO. E-002/CN-11-184

ORDER FINDING APPLICATION COMPLETE WHEN SUPPLEMENTED, SETTING DEADLINE FOR ALTERNATIVE PROPOSALS, AND INITIATING INFORMAL REVIEW PROCESS

PROCEDURAL HISTORY

On March 15, 2011, Northern States Power Company d/b/a Xcel Energy (Xcel) filed an application for a certificate of need for alterations to the Black Dog Generating Plant. This plant is located on the banks of the Minnesota River in the City of Burnsville, in Dakota County.[1]

By April 12, 2011, the Commission had received comments from the City of Burnsville and the Minnesota Department of Commerce's Office of Energy Security (the Department).

On April 15, 2011, Xcel filed replies to the Department's comments.

On May 12, 2011, the Commission met to consider this matter. At this time Xcel acknowledged that it had recently revised its forecast of customer demand for electricity, and stated that it planned to file the new forecast within the month.

[1] While Minn. Rules, part 7849.0200, subp. 5, provides for the Commission to rule within 30 days on whether a certificate of need application is complete, the Commission varied this rule. Order Varying Time (April 12, 2011), this docket.

FINDINGS AND CONCLUSIONS

I. Summary

The Commission finds as follows:

- Xcel's certificate of need application will become substantially complete upon the filing of information on Xcel's revised demand forecasts.

- Proposals for projects to substitute for Xcel's Black Dog Generating Plant proposal will be due July 1, 2011.

- The Commission will use its informal review process to develop the record in this matter.

II. Legal Background

Statute authorizes Xcel to invite outside parties to propose means by which Xcel should meet its resource needs,[2] and the Commission has established a process for Xcel to do so.[3] Under this process, when Xcel identifies the need for substantial new sources of generation, Xcel solicits proposals for meeting the need.[4]

Xcel may also propose its own plans for meeting the need and, where necessary, apply for a certificate of need from this Commission.[5] A certificate of need is required by anyone seeking to increase generating capacity by 50 MW or more by building an electric power generating plant, or by modifying an existing plant.[6]

Minnesota Rules Chapter 7849 sets forth the requirements for making an application for a certificate of need, as well as the ultimate criteria for demonstrating need. The Commission determines whether an application is substantially complete and may grant exemptions to filing requirements.

Where material facts are in dispute, the Commission refers cases to the Office of Administrative Hearings for a contested case proceeding.[7] Otherwise, the Commission may elect to address matters via informal proceedings.[8] But in either event, the Commission convenes at least one

[2] Minn. Stat. § 216B.2422. subd. 5.

[3] See generally *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2005 - 2019 Resource Plan,* Docket No. E-002/RP-04-1752.

[4] *Id.*

[5] Minn. Stat. § 216B.243

[6] Minn. Stat. § 216B.2421, subd. 2(1); Minn. Rules, part 7849.0030. By statute, a certificate of need is required for new generation plant with a capacity of 50,000 kilowatts, which equals 50 MW.

[7] Minn. Rules, part 7829.1000.

[8] Minn. Rules, part 7829.1200.

hearing to obtain public opinion on the necessity of granting a certificate of need and designates an employee to facilitate citizen participation in the hearing process,[9] and the Department prepares an environmental report.[10]

III. Xcel's Proposal

Currently Xcel generates approximately 250 MW from the coal-fueled Units 3 and 4 at its Black Dog Generating Plant. Xcel proposes to replace these units with a new 700 MW gas-fueled combined cycle generator to become operational in 2016. Until the new plant is operational, Xcel proposes to continue operating Units 3 and 4 but to burn only natural gas rather than coal. Because these changes would increase the plant's generating capacity by approximately 450 MW, Xcel requires a certificate of need.

Xcel argues that this proposal is the most cost-effective way to address the dual problems of aging infrastructure and growing demand. Xcel emphasizes that this proposal would make use of an existing generator site, located on a 35 acre parcel buffered within an approximately 1900 acre area owned by Xcel. Even the necessary transmission lines would be built on Xcel's property.

Xcel's application also includes a forecast of customer demand, and a plan for soliciting alternative proposals for addressing Xcel's needs. Xcel proposes that project developers submit their proposals by June 1, 2011. And Xcel proposes that if the Commission receives one or more alternative proposals, the Commission would refer this matter for a contested case proceeding.

IV. Party Comments

The City of Burnsville raised concerns regarding flood plain laws, changes in the location of the plant's entrance, a proposed trail adjoining the plant, storm sewer fees, building permits, and the project's consequences for people beyond the plant generally.

The Department reviewed the application to determine whether it fulfills the requirements of Minn. Rules, Chap. 7849. The Department identified additional information required to make the application complete, and recommended that the Commission accept the application as complete when Xcel supplemented the record. Xcel subsequently provided the requested information.

The Department states that it has identified no disputes as to the material facts alleged in Xcel's application, and does not expect any such disputes to develop. Thus the Department does not recommend that the Commission initiate a formal contested case proceeding in this docket unless some other party raises issues of material fact.

[9] Minn. Stat. § 216B.243, subd. 4; Minn. Rules, part 7829.2500, subp. 9.

[10] Minn. Rules, part 7849.1400.

V. Commission Action

A. Concerns of the City of Burnsville

The substantive concerns raised by the City of Burnsville do not pertain to the procedural questions currently before the Commission. Consequently the Commission will not address them at this time.

B. Application Completeness

The Commission has examined the record and finds that Xcel has complied with the filing requirements of Minn. Rules, Chap. 7849. However, changes in Xcel's demand forecast could have an impact on the need for, the size of, or the timing of the proposed project. The Commission therefore finds that Xcel's application will become substantially complete when Xcel files information regarding its new demand forecast.

The Commission's finding regarding the completeness of Xcel's application implies no judgment on the merits of the application. The Commission will address those merits at a later stage of these proceedings.

C. Notice to Alternative Providers

The Commission has reviewed Xcel's plan for soliciting alternative proposals from other potential suppliers, and finds the plan sufficient. However, the Commission is concerned that a June 1, 2011 deadline may not provide these suppliers with sufficient time in which to prepare alternative proposals. Consequently the Commission approves the proposed notice plan as modified to set July 1, 2011, as the date for suppliers to file their proposals.

D. Process for Reviewing the Merits

The Commission has the discretion to evaluate certificate of need requests using either contested case proceedings or an informal notice and comment process.[11] The informal process is a less formalized method of developing the record and provides an opportunity for the identification of contested issues, which would shape the scope of contested case proceedings, should they later be determined to be necessary.

No person has alleged that there are contested material facts for which a contested case proceeding is needed. No person has requested a contested case proceeding. There are no other factors pointing to a need for contested case proceedings. The Commission will therefore authorize staff to develop the record and prepare this case for Commission action without contested case proceedings under Minn. Stat. §§ 14.57 *et seq*.

[11] Minn. Rules, part 7829.1200.

Staff will manage the development of the case record by establishing necessary comment periods and ensuring compliance with statutory requirements such as the holding of one or more public hearings.

Under the informal review process, the Commission asks the Office of Administrative Hearings (OAH) to hold at least one public hearing, scheduled in conjunction with Commission staff. The Commission will also take the steps listed below to ensure adequate development of the record:

- Ask the Department to continue studying issues and to indicate during the hearing process its position on the reasonableness of granting a certificate of need for the project.
- Require Xcel to facilitate in every reasonable way the Department's continuing examination of the issues.
- Direct Xcel to place a compact disc (CD) or hard copy of the application for review in a government center and/or public library in the vicinity of the project.
- Direct Commission staff to work with the OAH's administrative law judge and the Department's staff in selecting suitable locations for a public hearing on the application.
- Direct Xcel to work with the staff of the Commission and the Department to arrange for 1) visible display ads providing notice of the hearings, 2) publication of the ads in newspapers of general circulation at least ten days prior to the hearings, and 3) proof that the selected newspapers published the ads.

Finally, the Commission will designate Bret Eknes, Facilities Planner, to facilitate and coordinate public participation in this proceeding as required by law.[12] He may be reached by telephone at (651) 201-2236, by fax at (651) 297-7073, and by email at bret.eknes@state.mn.us. The mailing address is 121 7th Place East, Suite 350, St. Paul, Minnesota 55101-2147.

ORDER

1. The Commission finds that Xcel's certificate of need application is substantially complete upon the date Xcel files information on its revised demand forecasts.
2. Xcel shall implement its notice plan soliciting developers to propose by July 1, 2011, alternative projects for meeting Xcel's need for new generation.
3. The Commission authorizes use of the informal review process, described above, to develop the record.

[12] Minn. Stat. § 216B.243, subd. 4.

4. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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NOTICE OF
APPLICATION FOR A CERTIFICATE OF NEED, AND INITIATING A COMPETITIVE RESOURCE ACQUSITION PROCESS

May 26, 2011

Northern States Power Company, a Minnesota corporation ("Xcel Energy"), has filed an application for Certificate of Need ("Application") for the Black Dog Generating Plant ("Plant") Repowering Project ("Project") and the associated transmission necessary for the direct interconnection of the Project.

The Project consists of replacing the coal-fired generating Units 3 and 4 at the Black Dog Plant site with about 700 MW of gas fired, combined cycle, generation located in what is now the coal storage yard at the Plant. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW in 2010. As part of the Project, these units will operate solely on natural gas during the construction phase and be shut down in 2016 after the new combined cycle facility is placed in service.

A need for future resources and the potential for this Project was identified in Xcel Energy's 2007 Resource Plan (Docket No. E002/RP-07-1572). The Minnesota Public Utilities Commission's ("Commission") Order in the 2007 Resource Plan directed the Company to "Continue to investigate repowering at Units 3 and 4 of the Black Dog Plant. Xcel's investigation shall include specific plans and time lines for the repowering." Our investigation of this Project concluded that it would be in the best interests of our customers to pursue the Project as described above, and the Company included the Project in our Five Year Action Plan in our 2010 Resource Plan (Docket No. E002/RP-10-825).

On March 15, 2011, Xcel Energy filed an application for Certificate of Need for the Project. The Application initiates a competitive resource acquisition process for generation resources established by the Commission. The contents of the Application describe and support the Company's proposal for addressing future capacity and energy needs. Interested parties can submit their Alternative Proposals and intervene in the process. Alternative Proposals are due to the Commission by 4:30 pm on July 1, 2011. A copy of our Application can be viewed at:

http://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/BlackDogCompleteApplicationPublic.pdf

Alternative Proposal Guidance can be viewed at:

http://www.xcelenergy.com/About_Us/Our_Company/Projects_&_RFPs/Black_Dog_Repowering_Project

Questions regarding the alternative review process and other procedural issues can be directed to the Commission's designated liaison, Susan Mackenzie, at 121 7th Place East, St. Paul, MN 55101, phone 651-201-2241, or susan.mackenzie@state.mn.us. Questions regarding alternative proposal preparation can be directed to Rick Peterson, resource planning analyst for Xcel Energy, at 612-330-5831, or richard.d.peterson@xcelenergy.com.

Certificate of Service

I, Mark Suel hereby certify that I have this day served copies of the foregoing document on the attached list of persons electronically, delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

Docket No. E002/CN-11-184

Dated this 26th of May, 2011

/s/

Mark Suel

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STATE OF MINNESOTA PUBLIC UTILITIES COMMISSION

DATE: June 22, 2011

TO: Service List

FROM: Burl W. Haar, Executive Secretary

DOCKET: E-002/CN-11-184

SUBJECT: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for approximately 450 MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project – Comments on Merits

RE: **NOTICE OF COMMENT PERIODS**

Take Note that on March 15, 2011 Northern States Power Company (Applicant) filed a certificate of need application (CN) with the Minnesota Public Utilities Commission (Commission) for approximately 450 MW of additional natural gas-fired combined cycle generation capacity and associated transmission interconnection facilities. The new facilities will also replace existing generation at the site of approximately 253 MW. The Applicant asserts that repowering is the most cost-effective way to meet growing needs.

The proposed project falls under the definition of "large energy facility" in Minn. Stat. § 216B.2421, Subd. 2 (1) because it has a combined capacity of 50,000 kilowatts or more and will need transmission lines, directly associated, to interconnect the plant to the transmission system. Under Minn. Stat. § 216B.243, Subd. 2, no large energy facility can be sited or constructed in Minnesota without the issuance of a CN by the Commission. The operable rules for this application are found in Minnesota Rules, Chapter 7849.

The Application was accepted as complete on June 14, 2011. The Commission is currently soliciting written comments on the merits of the proposed project, particularly whether there are any contested issues of fact with respect to the representations made in the Application. Initial comments will be accepted through **Monday, August 15, 2011** and replies through **Friday, September 16, 2011**. Comments should be *filed electronically* via the Commission's eDockets system at https://www.edockets.state.mn.us/EFiling and be addressed to Burl Haar, Executive Secretary, Minnesota Public Utilities Commission, 121 7th Place East, Suite 350, St. Paul, MN 55101-2147.

Questions may be directed to Commission staff person Bret Eknes at (651) 201-2236 or e-mail at bret.eknes@state.mn.us

This document can be made available in alternative formats (i.e., large print or audio) by calling 651.296.0406 (voice). Persons with hearing or speech disabilities may call us through Minnesota Relay at 1.800.627.3529 or by dialing 711.

CERTIFICATE OF SERVICE

I, Margie DeLaHunt, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
NOTICE OF CO MMENT PERIODS

Docket Number **E-002/CN-11-184**
Dated this **22nd** day of **June, 2011**

/s/ Margie DeLaHunt

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CALPINE CORPORATION

NYSE CPN

North Region Business Office
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July 22, 2011

Dr. Burl W. Haar, Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

VIA ELECTRONIC FILING

RE: *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Approximately 450 megawatts of Incremental Capacity for the Black Dog Generating Plant Repowering Project*; MPUC Docket No. E002/CN-11-184

Dear Dr. Haar:

Calpine Corporation ("Calpine"), through its affiliate Mankato Energy Center, LLC, pursuant to the May 25, 2011 Order of the State of Minnesota Public Utilities Commission ("Commission"), the May 26, 2011 Notice of Application for a Certificate of Need, and Initiating a Competitive Resource Acquisition Process (the "Notice") filed by Northern States Power Company ("Xcel Energy"), and Minn. R. ch. 7849, submits the attached Alternative Proposal, which contains a confidential appendix.

In its May 25, 2011, Order, the Commission stated that "Xcel shall implement its notice plan soliciting developers to propose by July 1, 2011, alternative projects for meeting Xcel's need for new generation." Order at 5. Beginning on July 1, 2011, however, and continuing until July 21, 2011, the Minnesota state government experienced a shutdown that affected the Commission. In particular, and as stated in a memorandum posted on the Commission's website dated June 24, 2011, during the government shutdown the Commission's "eFiling and eDockets system [were] closed for public use" and "[a]ll U.S. Mail and parcels from delivery services (Fed Ex, UPS, etc.) [were] not . . . delivered to the [Commission]." Consequently, Calpine was prevented from filing its Alternative Proposal with the Commission on the July 1, 2011, submission deadline date or during the government shutdown.

Calpine was prepared to submit its Alternative Proposal to the Commission on July 1, 2011, and worked to apprise all interested parties of its Alternative Proposal on that date. On July 1, 2011, Calpine attempted to eFile its Alternative Proposal with the Commission and called the Commission's offices to confirm the effects of the government shutdown. Calpine received automated messages from the Commission in response to these efforts that were consistent with the Commission's June 24 memorandum. Calpine then served Xcel Energy and all others on the service list for this proceeding with an emailed or mailed copy of Calpine's Alternative Proposal, with certain confidential information redacted.

The Alternative Proposal that Calpine now submits to the Commission is the same as the Alternative Proposal that Calpine served on the parties on July 1, 2011, except that Calpine has corrected a typographical error on the first line of page 19 by changing the word "ratepayer" to "shareholder". We believe that Calpine's actions in light of the Minnesota government shutdown comprised an effort to meet the requirements of the Commission and this proceeding in a difficult and unprecedented situation.

As an alternative to Xcel Energy's proposed Black Dog Repowering Project, Calpine is proposing a 345-megawatt expansion of its existing Mankato Energy Center through the addition of one Siemens 501 FD2 combustion turbine generator ("CTG") and one heat recovery steam generator ("HRSG"). The addition of the CTG and HRSG will allow Xcel Energy customers to benefit from Calpine's original infrastructure investment in developing the Mankato Energy Center site (located in Mankato, Blue Earth County, Minnesota) as a 2x2x1 combined-cycle facility.

Calpine's proposal utilizes the natural economies of scale from its existing Mankato Energy Center paired with Calpine's unmatched history of constructing and operating one of the largest fleets of gas turbines in the world.

As described in detail in the attached filing, Calpine proposes this alternative to Xcel Energy's Black Dog Repowering Project as being better suited to meet the needs identified by Xcel Energy in its application filed in this docket. Specifically, Calpine's Alternative Proposal, which makes use of Calpine's Mankato Energy Center from which Xcel Energy already receives power through a Power Purchase Agreement ("PPA"), can be efficiently and economically expanded to add 345 megawatts of generation within an estimated three years to meet Xcel Energy's 2016 forecasted capacity deficit of 320 megawatts. This measured approach to meeting forecasted need avoids the risk and cost of overbuilding generation presented by Xcel Energy's proposed 700 megawatt

Black Dog Repowering Project which will unnecessarily be borne by Xcel Energy ratepayers.

Moreover, across an array of additional considerations that the Commission must address, Calpine's Alternative Proposal outperforms Xcel Energy's Black Dog Repowering Project. Calpine's Alternative Proposal: (i) can be provided at a lower cost, (ii) minimizes environmental impacts, and (iii) unlike the Black Dog Repowering Project and similar to the existing Mankato Energy Center PPA, a new PPA will clearly shift the construction and delivery risk of the required megawatts to Calpine and provide ample measured protections.

In short, Calpine's Alternative Proposal matches the forecasts, needs, and goals identified by Xcel Energy in its application, and addresses those items in a clearly contractable manner superior to Xcel Energy's Black Dog Repowering Project. Calpine looks forward to the Commission's consideration of its Alternative Proposal.

Sincerely,

Steven Schleimer
Vice President, Governmental and
Regulatory Affairs

CALPINE CORPORATION ALTERNATIVE PROPOSAL

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Approximately 450 megawatts of Incremental Capacity for the Black Dog Generating Plant Repowering Project

PUC Docket No. No. E002/CN-11-184

July 1, 2011

Submitted by
Calpine Corporation and its Affiliate, Mankato Energy Center, LLC

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Calpine Corporation ("Calpine") and its affiliate, Mankato Energy Center, LLC, pursuant to the May 25, 2011 Order of the State of Minnesota Public Utilities Commission ("Commission"), the May 26, 2011 Notice of Application for a Certificate of Need, and Initiating a Competitive Resource Acquisition Process (the "Notice") filed by Northern States Power Company ("Xcel Energy"), and Minn. R. ch. 7849, submit this Alternative Proposal to the Black Dog Repowering Project for which Xcel Energy seeks a certificate of need. This Alternative Proposal includes confidential Appendix A containing details of Calpine's Alternative Proposal.

INTRODUCTION AND SUMMARY

Calpine specializes in the ownership, development, and operation of independent power facilities. Calpine has substantial expertise in independent power project development and has been and continues to be actively involved in the development and operation of numerous generation facilities throughout the United States. Calpine owns and operates the largest fuel-efficient fleet of gas-fired power plants in North America as part of its 28,000 megawatt generating portfolio.

Calpine is an active participant in the wholesale generation market in Minnesota. Calpine, through its subsidiary Mankato Energy Center, LLC, currently owns and operates the Mankato Energy Center ("MEC"), a 375-megawatt natural gas-fired combined-cycle generating facility located in the

City of Mankato, Minnesota, the output of which is sold to Xcel Energy under a long-term Power Purchase Agreement ("PPA"). The existing Mankato Energy Center was designed and constructed so that it can be expanded by an additional 345 megawatts in a very cost-effective and environmentally responsible manner.

Calpine's Alternative Proposal, which makes use of an expanded Mankato Energy Center, *i.e.*, "Mankato Unit 2" or "MEC Expansion", and is set forth in detail in the attached confidential appendix, is better suited to meet the forecasted energy needs of Xcel Energy's customers than the proposed over-sized Black Dog Repowering Project. Significantly, Xcel Energy's June 14, 2011 Supplemental Filing, which lowered Xcel Energy's earlier forecasted 2016 demand by 385 megawatts, demonstrates that the 700 megawatt Black Dog Repowering Project unnecessarily imposes costs on ratepayers for excess capacity.

According to its revised forecast, demand on Xcel Energy's distribution system is such that it faces a relatively small (70 megawatt) capacity deficit by 2016. However, Xcel Energy expects to retire existing coal-fired capacity during that timeframe, which increases its deficit in 2016 to 320 megawatts. Even with the need to replace such retired capacity, a 700-megawatt project is substantially in excess of currently-forecasted needs. Calpine's Alternative Proposal would provide 345 megawatts of power to address Xcel Energy's projected capacity deficit. Therefore, Calpine's Alternative Proposal better matches the needs of Minnesotans with an economical and logical expansion of an existing resource without the risk of an unnecessary overbuild or cost overruns.

ANALYSIS

I. CALPINE'S ALTERNATIVE PROPOSAL MEETS THE REGULATORY REQUIREMENTS FOR APPROVAL.

Calpine's proposed expansion of the Mankato Energy Center satisfies the criteria for consideration set forth in the Commission's rules and addresses the "Proposal Guidance and Transaction Fundamentals" identified by Xcel Energy in its "Alternative Proposal Guidance". Specifically, Minn. R. 7849.0110 provides that:

> The commission shall consider only those alternatives proposed before the close of the public hearing and for which there exists substantial evidence on the record with respect to each of the criteria listed in part 7849.0120.

The criteria regarding alternatives set forth in the referenced section include:

> (1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
>
> (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
>
> (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and
>
> (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives.

Minn. R. 7849.0120 subp. B.[1]

[1] These considerations are substantially similar to the "factors" that the Commission considers in resource plans and resource options under Minn. R. ch. 7843. *See* Minn. R. 7843.0500 subp. 3(A)–(E).

Here, as described in detail below and in the attached confidential appendix, the Alternative Proposal presented by Calpine merits approval by the Commission.

II. THE EXPANSION OF CALPINE'S MANKATO ENERGY CENTER PRESENTS AN ALTERNATIVE GENERATION RESOURCE THAT COMPARES FAVORABLY WITH XCEL ENERGY'S PROPOSED REPOWERING OF BLACK DOG UNITS 3 AND 4.

The expansion of Calpine's Mankato Energy Center achieves the goals of providing electricity to meet customer demand more effectively and efficiently than Xcel Energy's proposal and potentially, at the Commission's desire, can be in service prior to 2016 to economically and environmentally better replace existing coal-fired capacity upon its expected retirement. Moreover, Calpine's Alternative Proposal provides a better fit in terms of replacing coal-fired capacity in an increment of megawatts that satisfies reasonably forecasted future demand and, due to its more appropriate scale and use of existing site infrastructure, Calpine's Alternative Proposal exhibits cost savings over Xcel Energy's Black Dog Repowering Project.

Finally, Calpine's expansion proposal at least meets and in many cases surpasses the merits of Xcel Energy's proposal with respect to multiple additional aspects of the criteria identified in the regulations regarding alternatives in certificate of need proceedings, such as air emissions, water quality, reliability, use of advanced technology, and use of existing infrastructure. Calpine's expansion proposal is simply a better resource generation alternative at the present time than Xcel Energy's Black Dog Repowering Project.

A. Xcel Energy's Black Dog Repowering Project Overbuilds Capacity.

On March 15, 2011, Xcel Energy filed with the Commission an Application for a Certificate of Need for the Black Dog Generating Plant Repowering Project, in which it seeks approval to increase the electrical generating capabilities of the Black Dog Generating plant by approximately 450 megawatts. *See In the Matter of the Application of Northern States Power Company (Xcel Energy) for a Certificate of Need for approximately 450 megawatts of Incremental Capacity for the Black Dog Generating Plant Repowering Project* (Docket No. E-002/CN-11-184, March 15, 2011). Xcel Energy proposes to accomplish this by retiring the 250 megawatts of coal-fired generation at Black Dog and replacing it with 700 megawatts of utility-owned, gas-fired, combined-cycle generating capacity.

On June 14, 2011, Xcel Energy submitted a Supplemental Filing to its Application for Certificate of Need for the Black Dog Repowering Project ("Supplemental Filing"). In that filing, Xcel Energy stated that "[t]he Spring 2011 forecast predicts demand will be 385 megawatts ***lower*** by 2016 than the 2010 forecast" that it submitted in its original application. (Supplemental Filing at 1) (emphasis supplied). Xcel Energy attributed this decrease in forecasted demand to a "combination of reduced firm wholesale municipal load, lower actual peak demand in 2010, and updated economic performance indicators that predict slightly slower growth." (Supplemental Filing at 1 and 4.) Xcel Energy concludes that, "[a]s a result of the Spring 2011 forecast, we project a capacity deficit by 2016 of approximately 70 megawatts." (*Id*. at 1-2.) If Xcel Energy retires certain Black Dog coal units, that capacity deficit increases to 320 megawatts by 2016. Of this, 229 megawatts is related to reductions from firm wholesale load customers who will not be renewing their contracts. This component of Xcel Energy's forecast is, therefore, unlikely to rebound in the near term.

In its Supplemental Filing, Xcel Energy also describes the result of further weakening in demand trends: "If trends weaken further, it may be prudent to move more slowly and implement the project at a later time than January 2016." (Supplemental Filing at 5.) Nonetheless, Xcel Energy still advocates for the approval of its 700 megawatt Black Dog Repowering Project to address a 320 megawatt capacity deficit.

B. Calpine's Alternative Proposal Is Appropriate In Regard To The Size, Type, And Timing Of Xcel Energy's Needs.

Calpine operates a facility in Minnesota that is poised to replace retired coal generation capacity and meet the needs of Xcel Energy's customers, as forecasted by Xcel Energy. Minn. R. 7849.0120 subp. B(1).

Calpine, through its subsidiary Mankato Energy Center, LLC currently owns and operates the Mankato Energy Center, a 375-megawatt natural gas-fired combined-cycle generating facility located in the City of Mankato. The Mankato Energy Center entered commercial operations in June 2006 and is comprised of a

208-megawatt Siemens 501FD combustion turbine and a 330-megawatt Toshiba steam turbine. The plant currently operates under a long-term Power Purchase Agreement with Xcel Energy and interconnects with Xcel Energy's transmission system at its Wilmarth Substation at both 115kV and 345kV.

Calpine designed and constructed the Mankato Energy Center so that it could easily accommodate the installation of an additional combustion turbine. Indeed, the Mankato Energy Center was essentially designed as a full 2x2x1 720-megawatt combined-cycle unit that would be constructed on a phased-in basis. The current configuration (Unit 1) operates as a 1x1x1 combined-cycle facility with an existing steam turbine that is oversized relative to current operations. Thus, with an oversized steam turbine that can accommodate an additional combustion train, combined with other site characteristics that already have been designed and/or constructed to accommodate the expected installation of a second unit, the Mankato Energy Center can be expanded by an additional 345 megawatts in a timely, cost-effective and environmentally-responsible manner.

Mankato Unit 2 would include 290 megawatts of incremental baseload capacity plus 55 megawatts of incremental duct-fired peaking capability for a total of 345 megawatts. Assuming the timely completion of regulatory approvals and commercial negotiations, at this time Calpine projects that it could complete the construction of Mankato Unit 2 in time to enter commercial operation in 2016, or sooner if desired by the Commission due to the retirement of Black Dog Units 3 and 4. As Xcel Energy states in its Supplemental Filing: "Federal environmental initiatives lead us to conclude we cannot cost-effectively continue to operate Black Dog Units 3 and 4 on coal beyond 2014." (Supplemental Filing at 2.) Thus, just as Xcel Energy retires its coal-fired units, Mankato Unit 2 would be in operation with sufficient capacity to both replace the lost coal capacity and meet Xcel Energy's incremental generation needs, without the need to continue to run the existing Black Dog capacity inefficiently on natural gas.

In terms of capacity, Mankato Unit 2 is sized to replace the amount of capacity lost by the retirement of the coal-fired Black Dog Units 3 and 4. Especially in light of Xcel Energy's Supplemental Filing, it appears that forecasted demand and current supply warrant the replacement of this retired capacity, as opposed to a project that substantially increases net system capacity beyond currently-forecasted needs. Calpine's Mankato Unit 2 is custom-made to address the capacity deficits forecasted by Xcel Energy.

C. An Economic Comparison Of Mankato Unit 2 With Xcel Energy's Proposed Black Dog Repowering Project Demonstrates The Superiority Of Calpine's Alternative Proposal.

A comparison of Calpine's Alternative Proposal with Xcel Energy's Black Dog Repowering Project will demonstrate that Calpine's Alternative Proposal is more economic than Xcel Energy's proposal and better optimizes the benefits for the public interest. *See* Minn. R. 7849.0120 subp. B(2).

Although the cost information that Xcel Energy provides in its Application lacks sufficient detail and clarity to allow for verification, Xcel Energy contends that the cost of its proposed 700-megawatt combined-cycle unit is approximately

$600 million. (*See* Application at 1.12.) It is difficult to ascertain the detailed economics of the proposed Black Dog Repowering Project from the limited information available in Xcel Energy's Certificate of Need Application. The level of detail is, however, sufficient to at least strongly suggest that Calpine's proposed Mankato Unit 2 project is a quantifiable cost-effective option than the Black Dog Repowering Project, when viewed from the perspective of total installed capital costs and the subsequent rate of return required for such capital costs.

Construction of a 700-megawatt power plant for $600 million results in a cost of approximately $857 per kilowatt of installed capacity. As the largest owner and operator of modern, gas-fired, combined-cycle generating facilities in the United States, Calpine has significant expertise with respect to current market trends affecting power plant construction costs. Based on this experience and expertise, Calpine believes that a project installed capacity cost of $857/kw is an aggressively low estimate for the cost of new construction for the proposed Black Dog Repowering Project. However, even assuming Xcel Energy's projected construction cost is realistic, Calpine believes that it can supply capacity, energy and ancillary services for lower cost from the MEC Expansion. The fact that the existing site has been largely pre-built to accommodate a potential expansion provides significant economic advantages, as well as its smaller, more appropriate size compared with Xcel Energy's identified needs.

Moreover, there is no indication that Xcel Energy's cost number is a final number, not subject to increase, which places ratepayers at substantial risk for additional construction costs. Indeed, Xcel Energy's Supplemental Filing includes numerous references to the potential uncertainty related to its $600 million cost estimate and suggests that the proposed cost of the Black Dog Repowering Project is simply "…a high-level estimate[s] sufficient to judge among alternatives." (*See* Supplemental Filing at 8.) The Supplemental Filing further states that "…we believe that construction costs could come under significant upward pressure in the next couple of years due to rising prices and competition from other similar projects." (*Ibid*, at 2.)

Calpine has provided indicative pricing in the confidential appendix to this document, so that the Commission may evaluate the relative economics of the respective projects. However, in order to establish a level playing field, the Commission will need to evaluate Xcel Energy's Black Dog Repowering Project on a risk-equivalent basis. In particular, the Commission must ascertain whether the estimated $600 million cost for Xcel Energy's Black Dog Repowering Project is a firm estimate or a preliminary estimate subject to potential cost escalation, and whether Xcel Energy is willing to be bound by that estimate. In direct contrast to Xcel Energy's current proposal, upon execution of a binding PPA, the costs of the MEC Expansion project will be fixed, with Calpine bearing the risk of performance related to its agreed-upon contract terms and pricing.

When comparing a utility self-build proposal with a competitive alternative that would be procured via a PPA mechanism, it is important for the Commission to determine which structure represents the lowest overall risk for the utility's ratepayers. Traditionally, utility self-build projects are subject to traditional ratebase regulation without the inherent performance incentives provided by resources sourced via competitive procurement. For example, once a PPA is executed between a utility and its commercial counterparty, the allocation of risk between the utility (and its ratepayers) and the competitive provider (and its shareholders) is clearly defined. Important elements of these commercial risks include items such as contract pricing, performance guarantees and, importantly, risks associated with the capital costs and general operations and maintenance costs of the asset.

Subject to Commission approval of its Alternative Proposal, Calpine stands ready, willing and able to enter into direct negotiations with Xcel Energy that would result in firm and binding terms and conditions related to the construction and operation of the MEC Expansion. After execution of such transaction, Calpine and its shareholders will bear the risk that the project can be completed and will perform as proposed. Therefore, in order to evaluate the competing proposals on a level playing field, the Commission should consider the important long-term economic benefits of shifting these substantial commercial risks away from Xcel Energy's ratepayers and onto Calpine and its shareholders. In the alternative, the Commission should consider requiring Xcel Energy and its shareholders to bear a similar level of risk with respect to its self-build proposal.

In its Application, Xcel Energy evaluates various alternatives to its proposed Black Dog combined-cycle project. However, Xcel Energy focuses exclusively on self-build alternatives and, notably, remains silent on the universe of alternatives that potentially could be supplied by competitive power providers. Xcel Energy's application appears to justify this limited approach based upon alleged concerns regarding the accounting treatment accorded PPAs. *See* Application at 4.3.2. Xcel Energy alleges that:

> ...a PPA that must be treated as a capital lease can have a significant impact on the Company's capital structure. The result would likely be a higher debt to equity ratio and an impact to the cost of capital.

Xcel Energy concludes its observations regarding PPAs by stating that this potential impact "will need to be incorporated into the evaluation of any PPA alternative in order to fairly compare it to the [Black Dog Repowering] Project." *Id*.

The concerns and impacts that Xcel Energy identifies have no place in the comparison between the Black Dog Repowering Project and a PPA alternative such as that offered by Calpine. The National Association of Regulatory Utility Commissioners addressed Xcel Energy's concerns in its report entitled *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (July 2008) (the "NARUC Report"). In that report, NARUC noted that "...there is relatively little research that has assessed how alternative means of fulfilling resource needs impact a utility's overall cost of debt or return on equity", and identified one study that suggested that "PPAs have little effect on a utility's cost of capital, while utility self-builds actually raise the utility's cost of capital." NARUC Report at 36-37, citing Kahn, Edward, et al., "Impact of power purchased [*sic*] from non-utilities on the utility cost of capital," *Utilities Policy* 5(1): 3-11, 1995). The NARUC Report stated that:

> In fact, there is even uncertainty regarding how PPAs impact the credit ratings developed by credit-rating agencies. While certain credit agencies have clearly described certain quantitative balance sheet adjustments made for PPAs, they also note that these are only one among many possible adjustments that may affect a utility's credit rating. However, because many of these other considerations are less clearly described and are more qualitative in nature, determining a PPA's net impact on utility credit ratings is difficult.

(*Id*. at 37; footnote omitted.)

Based upon this uncertainty and difficulty, NARUC concluded that:

> These considerations again caution against assessment of debt equivalency, or any risk factor, outside of a comprehensive evaluation that accounts for all of the various risks posed by alternative utility obligations and commitments from the standpoint of consumers, while leaving the utility fairly compensated for its financial risks. These issues are normally addressed by commissions in general rate cases in which regulators examine the capital structure and cost of capital of the utilities they regulate.

(*Id*.; *see also id.* at 37 n. 62, noting that procurements in California, Colorado, Connecticut, and Georgia do not use debt equivalency adjustments.)

In light of the analysis included in the NARUC Report, the Commission should be very hesitant to impose a debt equivalency factor on an Alternative Proposal provided as a PPA in this proceeding. The imposition of such a debt equivalency burden could both skew the comparison of the utility self-build project and the Alternative Proposal and the choice ultimately made by the

Commission. A determination to preclude a debt equivalency burden at the evaluation stage is supported by the following:

1. There is no basis to conclude that a single PPA could lower the debt rating of a utility and result in a modification to the cost of capital and therefore it would be unfair to impose a debt equivalency burden on the comparison of a single PPA to the utility's self-build project;

2. Even though the NARUC Report recognizes that a utility self-build project actually raises the utility's cost of capital, Xcel Energy is not seeking to impose a similar debt equivalency factor on its own self-build project;

3. The imposition of a debt equivalency factor on a single PPA does not take into consideration the benefits which may accrue from entering into a PPA rather than permitting a utility self-build project. Such benefits could include construction and operation risk transfer from ratepayers to the independent power producer. Such benefits are ignored through the imposition of a debt equivalency factor on a PPA;

4. Even if a single PPA or a series of PPAs were considered to have some potential impact on the cost of capital for a utility, the only legitimate manner in which to consider those impacts would be in a general rate case where the Commission could examine Xcel Energy's capital structure and cost of capital and could take into consideration all of the risk factors, including those unrelated to a power purchase agreement, that might affect the capital structure.

The Commission should not impose a debt equivalency burden on a single PPA in comparison to Xcel Energy's self-build project. If the Commission considers a debt equivalency argument at all, it should do so as part of a cost of capital proceeding in a rate case and not related to an individual PPA comparison.

Calpine, therefore, recommends that the Commission consider and evaluate a scenario under which Xcel Energy would retire existing Units 3 and 4 as planned in 2014, relying on Mankato Unit 2 to provide replacement capacity. Calpine believes it can provide reliable capacity and energy to Xcel Energy at lower cost and with less overall risk than what ratepayers would experience if Xcel Energy developed the Black Dog Repowering Project at a high-level installed cost of $857/kw.

The advantage in relative construction costs related to the MEC Expansion, as demonstrated in the confidential appendix, will directly translate into financial benefits for Minnesota ratepayers, both in terms of replacing the existing Black Dog capacity and meeting Xcel Energy's forecasted incremental generation requirements.

D. The Expansion Of Calpine's Mankato Energy Center Minimizes Adverse Effects Upon The Environment.

The Commission must consider the "effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives." Minn. R. 7849.0120 subp. B(3). Calpine's Mankato Unit 2 Alternative Proposal minimizes adverse effects upon the environment more effectively than Xcel Energy's Black Dog Repowering Project in a number of ways.

First, installing Mankato Unit 2 for commercial operation can accommodate the complete retirement of Black Dog Units 3 and 4, as Xcel Energy believes would be necessary. (Application at 1-12.) This will lead to the significant, immediate environmental benefit of reduced coal emissions and provides dramatic environmental and energy efficiency benefits.

Second, installation of Mankato Unit 2 would be advantageous with respect to impacts on the Minnesota River—the river on which both Black Dog and the Mankato Energy Center lie—compared with Xcel Energy's proposal. The use of cooling water at thermal power plants is a highly sensitive environmental issue subject to stringent regulatory requirements. Calpine's proposal represents clear environmental advantages because it (i) relies on closed-loop, mechanical draft cooling, rather than once-through cooling and (ii) utilizes treated wastewater purchased through an innovative and award-winning agreement with the City of Mankato that results in a net reduction in pollution in the Minnesota River.[2] Xcel Energy states, on the other hand, that the new facility resulting from its repowering proposal would "utilize the cooling water allocated to the existing coal units" (Application at 1-13) and it remains unclear whether Xcel Energy's proposed $600 million construction cost includes the cost of mechanical draft cooling or whether its estimate assumes the continued use of existing intake and discharge structures and the ongoing use of once-through cooling.

Third, Mankato Unit 2 can at least match the various other environmental benefits Xcel Energy claims for its Black Dog Repowering Project. For example, Mankato Unit 2:

- involves "Brownfield" site impacts rather than any Greenfield impact;

[2] Utilizing additional treated municipal wastewater would also provide direct additional economic benefits to the City of Mankato. In 2006 the City of Mankato won a Governor's MnGREAT Award for the beneficial use of treated wastewater related to supplying the Calpine Mankato power plant. *See* http://www.pca.state.mn.us/index.php/view-document.html?gid=4576.

- provides at least the same environmental benefit related to the elimination of coal at Units 3 and 4;
- utilizes existing natural gas and electric power transmission infrastructure; and
- avoids proliferation of additional generating sites and/or transmission corridors.

Calpine's Mankato Unit 2 Alternative Proposal is the optimal resource option with regard to minimizing adverse effects upon the environment.

E. The Expansion Of Calpine's Mankato Energy Center Enhances Xcel Energy's Ability To Take Advantage Of More Efficient Technologies.

The Commission must consider an alternative proposal with respect to its "type" and its effect on the socioeconomic environment. Minn. R. 7849.0120 subp. B(1) and (3). Calpine's Alternative Proposal is superior to Xcel Energy's Black Dog Repowering Project in a number of respects relating to these considerations.

The 2014 retirement of Black Dog Units 3 and 4, facilitated by installation of Calpine's Mankato Unit 2 alternative, allows Xcel Energy and its ratepayers to benefit from the more efficient combined-cycle generating technology that Calpine's alternative would utilize. This technology would provide energy with a attractive heat rate and far better environmental profile.

Installation of Mankato Unit 2 would also improve the overall plant efficiency and operational performance of the existing Mankato facility by making more efficient utilization of the existing Toshiba steam turbine and thereby improving the existing plant's overall heat rate. Calpine's Mankato Unit 2 alternative is substantially more effective than Xcel Energy's repowering proposal with regard to maximizing the use of efficient technology.

Calpine's Alternative Proposal also limits the risk otherwise presented in Xcel Energy's Black Dog Repowering Project in a number of ways.

First, Mankato Unit 2 could fill any potential need by Xcel Energy to acquire short term peaking capacity from the market, and a PPA between Calpine and Xcel Energy for the capacity and energy produced by Mankato Unit 2 would serve as a hedge against any market price risk Xcel Energy would otherwise have to take.

Second, Calpine's Mankato Unit 2 alternative avoids any potential risk that Xcel Energy does <u>not</u> receive any "cost synergies" and construction benefit from existing Black Dog Units 3 and 4 infrastructure: For example, the risk that Xcel Energy would not maintain its grandfathered rights to continue to use existing intake and discharge structures. These risks, if not avoided, add more uncertainty with respect to Xcel Energy's already potentially optimistic cost assumptions.

Third, Calpine is willing to offer Mankato Unit 2 pursuant to a PPA agreement where Calpine, rather than Xcel Energy or its ratepayers, bear the consequences of several risks related to potential construction cost overruns, construction delay, operational issues, and other such variables and risks attendant to a large scale generation development project.

Simply put, a number of financial, social, and technological risks that Xcel Energy otherwise would endure under its proposal will be shifted to Calpine and its shareholders under an agreed-upon PPA. Xcel Energy is well aware of the advantages of such risk-shifting, as evidenced by its decision to enter into a risk-shifting PPA with Calpine for power generated by Unit 1 of the Mankato Energy Center. A PPA relating to the installation of Mankato Unit 2 would confer similar benefits to Xcel Energy and its ratepayers. In addition, given their existing contractual relationship, Calpine's Alternative Proposal does not include uncertainty with respect to the anticipated dealings between these two entities.

In short, Calpine's Mankato Unit 2 alternative limits or eliminates a number of risks attendant to Xcel Energy's Black Dog Repowering Project.

F. The Expansion Of Calpine's Mankato Energy Center Improves The Adequacy And Reliability Of Service.

The Commission must consider the "expected reliability" of an alternative proposal Minn. R. 7849.0120 subp. B(4). Calpine's Mankato Unit 2 alternative is more reliable than Xcel Energy's Black Dog Repowering Project. With integrated baseload and peaking capability, Mankato Unit 2 could fill Xcel Energy's projected need to otherwise acquire short term peaking capacity from the market. Moreover, Mankato Unit 2 provides much needed operating flexibility to reliably accommodate the inclusion of additional intermittent wind or other renewable generating capacity on Xcel Energy's system.

Across the array of considerations that the Commission must address, Calpine's Alternative Proposal outperforms Xcel Energy's Black Dog Repowering Project.

CONCLUSION

The smaller relative size of an expansion of the Mankato Energy Center is an advantage over repowering Black Dog Units 3 and 4 because it would allow any new capacity to be built on a more incremental basis, appropriate to the apparent slowing in the growth of demand, and with the opportunity for an earlier in-service date if desired. In this scenario, Calpine would install Mankato Unit 2 for commercial operation and Xcel Energy would simultaneously retire Black Dog Units 3 and 4.

With 290 megawatts of incremental baseload or intermediate capacity and an additional 55 megawatts of integrated peaking capability, the 345 megawatts available through Mankato Unit 2 is an ideal fit to replace the forecasted 320 megawatt capacity deficit that Xcel Energy currently projects for 2016. Under this scenario, and depending on the outcome of Xcel Energy's ongoing modeling, the installation of Mankato Unit 2 may allow Xcel Energy to delay or even fully avoid construction of the New Black Dog Unit, or to allow that unit to be constructed on a phased-in basis that would minimize ratepayer impacts.

Dated this 1st day of July, 2011.

CALPINE CORPORATION

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Calpine Corporation and Mankato Energy Center, LLC
Proposal to the Commission
July 1, 2011

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STATE OF MINNESOTA PUBLIC UTILITIES COMMISSION

DATE: July 25, 2011

TO: Service List

FROM: Burl W. Haar, Executive Secretary

DOCKET: E-002/CN-11-184

SUBJECT: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for approximately 450 MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project

RE: **COMMENT PERIODS on MERITS CANCELLED**

Take Note that on June 22, 2011 the Minnesota Public Utilities Commission (Commission) issued a Notice Soliciting Comments on the Merits of the March 15, 2011 Northern States Power Company d/b/a Xcel Energy (Applicant) Black Dog application for a certificate of need. This Notice was issued assuming the use of the Informal Review Process for the Application.

An alternative proposal has been submitted in the proceeding and the process now requires the use of a contested case proceeding to evaluate the merits of both projects.

The review process, as established, requires that if an alternative proposal(s) is submitted, the applications for all projects will be referred to the Office of Administrative Hearings (OAH) for a contested case proceeding to determine the merits of each proposal.

THEREFORE, the comment deadlines of August 15, 2011 and September 16, 2011 established in the Commission's June 22, 2011 Notice are CANCELLED.

The procedural issue of the referral of this matter to the OAH for a contested case proceeding will be brought before the Commission at its regularly scheduled Agenda Meeting of August 11, 2011.

Questions may be directed to Commission staff person Bret Eknes at (651) 201-2236 or e-mail at bret.eknes@state.mn.us

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CERTIFICATE OF SERVICE

I, Robin Rice, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
COMMENT PERIODS on MERITS CANCELLED

Docket Number E-002/CN-11-184

Dated this 25th day of July, 2011

/s/ Robin Rice

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Northern States Power Company for a Certificate of Need for Approximately 450 MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project – Alternative Proposal	ISSUE DATE: August 19, 2011 DOCKET NO. E-002/CN-11-184 NOTICE AND ORDER FOR HEARING

PROCEDURAL HISTORY

On March 15, 2011, Northern States Power Company d/b/a Xcel Energy (Xcel) filed an application for a certificate of need for approximately 450 megawatts (MW) of incremental capacity, to increase to a total of 700 MW the Black Dog Generating Plant.

According to Xcel, the repowering project is the most cost effective way to address growing demand and aging infrastructure. The plant site is located in the City of Burnsville, in Dakota County. As proposed, the project will replace two coal-fired generating units (Units 3 and 4) with approximately 700 MW of natural gas-fueled combined cycle generation, located in what is currently the coal storage yard.

On May 25, 2011, the Commission issued its Order Finding Application Complete When Supplemented, Setting Deadline for Alternative Proposals, and Initiating Informal Process in this docket. The Order accepted Xcel's application as complete upon the submission of a supplemental filing discussing the change in demand demonstrated in its most recent forecast analysis.

The Order also set a deadline for proposals from alternative providers, which was subsequently extended until August 1, 2011. Finally, the Commission initiated review of the merits of the Black Dog proposed project under the Commission's informal review process.

On June 14, 2011, Xcel filed the supplemental information to make its application complete.

On July 22, 2011, Calpine Corporation (Calpine) filed a petition to intervene and an alternative proposal with the Commission. The alternative proposal is for a 350 MW expansion of Calpine's existing Mankato Energy Generation Station (Mankato Station), a 375 MW natural gas-fired combined cycle generating facility in the City of Mankato, and a directive to Xcel to negotiate a power purchase agreement for that project.

On August 11, 2011, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Calpine's Alternative Proposal Accepted as Substantially Complete

In a May 31, 2006 order,[1] the Commission approved a bidding process under Minn. Stat. § 216B.2422, subd. 5, which established a two-track competitive resource acquisition process -- using the framework of the certificate of need process when Xcel submits a self-build proposal, and using a formal competitive bidding process when Xcel does not submit its own proposal. The operational details of both processes, as approved by the Commission, are set forth in the Department of Commerce's January 30, 2006 comments in Docket 04-1752.

Minnesota Rules Chapter 7849 sets forth the requirements for making an application for a certificate of need, as well as the ultimate criteria for demonstrating need. In this matter, Xcel offered a Guidance Document as part of its initial application,[2] for applicants preparing alternative proposals.

The Commission has examined the record and reviewed Calpine's proposal for compliance with the requirements of the May 31, 2006 order, including the filing requirements incorporated from the Department's earlier comments, and finds that Calpine's alternative proposal for the expansion of the Mankato Energy Center is substantially complete.

II. Jurisdiction and Referral for Contested Case Procedures

The Commission has jurisdiction over Xcel's request for a Certificate of Need under Minn. Stat. § 216B.243 and Minn. Rules, Chapter 7849 and 7829.

The Commission finds that it cannot satisfactorily resolve all questions regarding the prudence of the proposed repowering proposals on the basis of the current filings. The Commission will therefore refer the matter to the Office of Administrative Hearings for contested case proceedings.

III. Issues to be Addressed

The ultimate issues in this case are whether Xcel has demonstrated a need for increased capacity; if so, how much additional capacity; whether either Xcel's proposal or Calpine's proposal is reasonable, prudent, and in compliance with all applicable statutory requirements in Minn. Stat. § 216B.243, and Minn. Rules, Chapters 7849 and 7829; which proposal is the most reasonable and prudent, considering the applicable statutory requirements; and, whether a more reasonable and

---

[1] See generally *In the Matter of Northern States Power Company d/b/a/ Xcel Energy's Application for Approval of its 2004 Resource Plan, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing* , Docket No. E-002/RP-04-1752 (May 31, 2006).

[2] Xcel Application, this docket (March 15, 2011) at Chapter 4.

prudent alternative to the proposals has not been demonstrated by a preponderance of the evidence on the record**.**

The parties may also raise and address other issues relevant to that determination.

IV. Procedural Outline

A. Administrative Law Judge

The Administrative Law Judge assigned to this case is Richard C. Luis. His address and telephone number are as follows: Office of Administrative Hearings, 600 North Robert Street, St. Paul, Minnesota 55101; (651) 361-7843. The mailing address of the Office of Administrative Hearings is P.O. Box 64620, St. Paul, Minnesota 55164-0620.

B. Hearing Procedure

- *Controlling Statutes and Rules*

Hearings in this matter will be conducted in accordance with the Administrative Procedure Act, Minn. Stat. §§ 14.57-14.62; the rules of the Office of Administrative Hearings, Minn. Rules, parts 1400.5100 to 1400.8400; and, to the extent that they are not superseded by those rules, the Commission's Rules of Practice and Procedure, Minn. Rules, parts 7829.0100 to 7829.3200.

Copies of these rules and statutes may be purchased from the Print Communications Division of the Department of Administration, 660 Olive Street, St. Paul, Minnesota 55155; (651) 297-3000. These rules and statutes also appear on the State of Minnesota's website at www.revisor.mn.gov/pubs.

The Office of Administrative Hearings conducts contested case proceedings in accordance with the Minnesota Rules of Professional Conduct and the Professionalism Aspirations adopted by the Minnesota State Bar Association.

- *Right to Counsel and to Present Evidence*

In these proceedings, parties may be represented by counsel, may appear on their own behalf, or may be represented by another person of their choice, unless otherwise prohibited as the unauthorized practice of law. They have the right to present evidence, conduct cross-examination, and make written and oral argument. Under Minn. Rules, part 1400.7000, they may obtain subpoenas to compel the attendance of witnesses and the production of documents.

Parties should bring to the hearing all documents, records, and witnesses necessary to support their positions.

- *Discovery and Informal Disposition*

Any questions regarding discovery under Minn. Rules, parts 1400.6700 to 1400.6800 or informal disposition under Minn. Rules, part 1400.5900 should be directed to Bret Eknes, Energy Facilities Planner, Minnesota Public Utilities Commission, 121 7th Place East, Suite 350, St. Paul, Minnesota 55101-2147, (651) 201-2236, by fax at (651) 297-7073, and by email at bret.eknes@state.mn.us; or Anna Jenks, Assistant Attorney General, 1100 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, (651) 282-5735.

- *Protecting Not-Public Data*

State agencies are required by law to keep some data not public. Parties must advise the Administrative Law Judge if not-public data is offered into the record. They should take note that any not-public data admitted into evidence may become public unless a party objects and requests relief under Minn. Stat. § 14.60, subd. 2.

- *Accommodations for Disabilities; Interpreter Services*

At the request of any individual, this agency will make accommodations to ensure that the hearing in this case is accessible. The agency will appoint a qualified interpreter if necessary. Persons must promptly notify the Administrative Law Judge if an interpreter is needed.

- *Scheduling Issues*

The times, dates, and places of public and evidentiary hearings in this matter will be set by order of the Administrative Law Judge after consultation with the Commission and intervening parties.

- *Notice of Appearance*

Any party intending to appear at the hearing must file a notice of appearance (Attachment A) with the Administrative Law Judge within 20 days of the date of this Notice and Order for Hearing.

- *Sanctions for Non-compliance*

Failure to appear at a prehearing conference, a settlement conference, or the hearing, or failure to comply with any order of the Administrative Law Judge, may result in facts or issues being resolved against the party who fails to appear or comply.

C. Parties and Intervention

The current parties to this case are Xcel Energy, the Minnesota Department of Commerce, and Calpine. Other persons wishing to become formal parties shall promptly file petitions to intervene with the Administrative Law Judge. They shall serve copies of such petitions on all current parties and on the Commission. Minn. Rules, part 1400.6200.

D. Prehearing Conference

A prehearing conference will be held on September 12**,** 2011, at 9:30 a.m., in the Small Hearing Room at the offices of the Public Utilities Commission, 121 Seventh Place East, Suite 350, St. Paul, Minnesota 55101-2147.

Parties and persons intending to intervene in the matter should participate in the conference prepared to discuss time frames and scheduling. Other matters which may be discussed include the locations and dates of hearings, discovery procedures, settlement prospects and similar issues. Potential parties are invited to attend the pre-hearing conference and to file their petitions to intervene as soon as possible.

V. Application of Ethics in Government Act

The lobbying provisions of the Ethics in Government Act, Minn. Stat. §§ 10A.01 et seq., apply to rate setting cases. Persons appearing in this proceeding may be subject to registration, reporting, and other requirements set forth in that Act. All persons appearing in this case are urged to refer to the Act and to contact the Campaign Finance and Public Disclosure Board, telephone number (651) 296-5148, with any questions.

VI. Ex Parte Communications

Restrictions on ex parte communications with Commissioners and reporting requirements regarding such communications with Commission staff apply to this proceeding from the date of this Order. Those restrictions and reporting requirements are set forth at Minn. Rules, parts 7845.7300-7845.7400, which all parties are urged to consult.

VII. Environmental Report Requested

The Department of Commerce's Energy Facilities Permitting Unit has initiated its environmental review and the development of an Environmental Report on Xcel's Black Dog project, with a public meeting on the scope of the report later this month.

The Commission requests the Department's Energy Facilities Permitting Unit to timely complete an appropriate environmental review on the Calpine proposal, and to develop a separate report or an appendix to the Black Dog Environmental Report on the project. Calpine has agreed to provide the Department with any relevant information necessary to conduct the review.

ORDER

1. The Commission accepts Calpine's alternative proposal for the expansion of the Mankato Energy Center as substantially complete.

2. The Commission hereby refers this matter to the Office of Administrative Hearings for contested case proceedings, as set forth above.

3. The Commission requests the Department of Commerce's Energy Facilities Permitting Unit to perform a timely environmental review of the proposed expansion of the Mankato Energy Center.

4. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

This document can be made available in alternative formats (i.e., large print or audio tape) by calling 651.296.0406 (voice). Persons with hearing or speech disabilities may call us through Minnesota Relay at 1.800.627.3529 or by dialing 711.

ATTACHMENT A

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Application of Northern States Power Company for a Certificate of Need for Approximately 450 MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project – Alternative Proposal

MPUC Docket No. E-002/CN-11-184

OAH Docket No.

NOTICE OF APPEARANCE

Name, Address and Telephone Number of Administrative Law Judge:

Richard C. Luis, Office of Administrative Hearings, 600 North Robert Street, St. Paul, Minnesota 55101; Mailing Address: Box 64620, St. Paul, Minnesota 55164-0620; Telephone Number: (651) 361-7843.

TO THE ADMINISTRATIVE LAW JUDGE:

You are advised that the party named below will appear at the above hearing.

NAME OF PARTY:

ADDRESS:

TELEPHONE NUMBER:

PARTY'S ATTORNEY OR OTHER REPRESENTATIVE:

OFFICE ADDRESS:

TELEPHONE NUMBER:

SIGNATURE OF PARTY OR ATTORNEY:_______________________________________

414 Nicollet Mall
Minneapolis, Minnesota 55401

October 7, 2011

-VIA ELECTRONIC FILING-

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: RESOURCE PLAN – REQUEST FOR EXTENSION
Docket No. E002/RP-10-825

Dear Dr. Haar:

On August 2, 2010, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), submitted to the Minnesota Public Utilities Commission (the "Commission"), our Resource Plan for the years 2011 to 2025. For a number of reasons, the review of this plan has been extended.

Resource planning is a dynamic, not static process, and, as so often happens, some elements in both our five year action plan and longer range planning have changed since we filed this resource plan in August of last year. We have made progress and met challenges in our efforts to acquire renewable resources. We have encountered difficulties in the implementation of capacity upgrades at our nuclear plants which are affecting the size and timing of the projects. As we reported in the Black Dog Repowering docket (E002/CN-11-184), changing energy forecasts may affect the timing of the project.

Over the last year our forecast of future customer electric needs has continued to decline as predictions of economic performance remain soft. We have just received the preliminary results of our fall forecast update which indicate further slowing in growth. As a result, we believe it would be useful to provide a comprehensive update to our Resource Plan so that parties can consider the most recent information in the preparation of their comments. To facilitate the exchange of comments based on the best information possible we respectfully request the schedule be revised to accommodate this update.

We would like the opportunity to incorporate the forecast information we just received and can provide a comprehensive update by December 1, 2011. It would seem appropriate then to provide interested parties 60 days to complete their comments on our plan.

We recognize the Commission and others have raised concerns about the length of time for review in past resource plan proceedings. However, given the circumstances of this docket, our request to provide an update before others comment should, in the end, shorten the overall remaining review time by reducing the need for additional comment cycles to respond to the changing economic and energy environment we face.

Pursuant to Minn. Stat. §216.17, subd. 3, we have electronically filed this document with the Commission, and copies have been served on all parties on the attached service list.

Thank you for your consideration of our request. Please do not hesitate to contact me at (612) 330-6732 or james.r.alders@xcelenergy.com if you have any questions.

SINCERELY,

/s/

JAMES ALDERS
DIRECTOR REGULATORY ADMINISTRATION

c: Service List

CERTIFICATE OF SERVICE

I, Mark Suel hereby certify that I have this day served copies of the foregoing document on the attached list of persons electronically, delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

DOCKET NO. E002/RP-10-825

Dated this 7th day of October, 2011

/s/

Mark Suel

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BRIGGS
BRIGGS AND MORGAN

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October 10, 2011

Michael C. Krikava
(612) 977-8566
mkrikava@briggs.com

ELECTRONIC FILING

Hon. Richard C. Luis
Administrative Law Judge
PO Box 64620
St. Paul, MN 55164-0620

Re: In the Matter of Application of Northern States Power Company for Certificate of Need for the Black Dog Generating Plant Repowering Project
MPUC Docket No. E-002/CN-11-184
OAH Docket No. 7-2500-22228-2

Dear Judge Luis:

On March 15, 2011, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), made application to the Minnesota Public Utilities Commission (the "Commission"), for a Certificate of Need for about 700 MW of natural gas fueled, combined cycle generation to replace the 250 MW of existing coal fueled generation remaining at the Black Dog Power Plant. On May 13, 2011, the Company submitted an application to the Commission for a Generation Site Permit and Transmission Line Route Permit for the Project in MPUC Docket No. E002/GS-11-307. On June 14, 2011, Xcel Energy filed an update in this Docket discussing updated forecast information. This matter was referred to the present contested case.

As discussed at the September 12, 2011, First Prehearing Conference in this matter, changing forecasts may affect the timing of the Black Dog Repowering Project and Xcel Energy committed to provide stakeholders with updated information as it becomes available. Over the last year our forecast of future customer electric needs has continued to decline as predictions of economic performance remain soft. We have just received the preliminary results of our fall forecast update which indicate further slowing in growth. On October 7, 2011, we submitted a request to delay the comment period in our pending Resource Plan filing (Docket No. E002/RP-10-825) in order to prepare a comprehensive update to include the fall 2011 forecast information. In that Docket, we requested until December 1, 2011 to complete and file the comprehensive update. On October 10, 2011, the Commission issued a notice granting the December 1, 2011 extension.

As part of our comprehensive update, we will be reviewing the timing and need for the Black Dog Repowering Project and we plan to make appropriate filings in this Docket soon after the

December 1, 2011, filing made in the Resource Plan docket. We believe it would be useful to provide this updated information for review in the present Docket before this Docket proceeds further. As a result, we respectfully request that all action in this Docket should be placed on hold, including all discovery. We suggest that after the December 1, 2011, filing of the comprehensive update in the Resource Plan docket, that the parties reconvene to update the schedule for the present proceeding.

Xcel Energy has alerted the parties to this proceeding about this development and this request. If parties or the Judge prefer, we can submit a formal motion for the requests made here. We have filed a separate letter in the corresponding permitting proceeding (MPUC Docket No. E002/GS-11-307) in an effort to keep all stakeholders informed.

Please do not hesitate to contact the undersigned at 612-977-8566 or at mkrikava@briggs.com if you have any questions. Thank you.

Very truly yours,

BRIGGS AND MORGAN, P.A.

/s/ Michael C. Krikava

Michael C. Krikava

MCK/rlh
cc: Service List
Docket E-02/GS-11-307

IN THE MATTER OF APPLICATION OF NORTHERN STATES POWER COMPANY FOR CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT

CERTIFICATE OF SERVICE
MPUC Docket No. E002/CN-11-184

Roshelle Herstein certifies that on the 10th day of October, 2011, she filed a true and correct copy of the Letter to ALJ Luis by posting it on www.edockets.state.mn.us in the above-referenced docket. In a addition, a copy of this letter was posted on www.edockets.tate.mn.us in Docket No. E-02/GS-11-307. Said document(s) were also served via U.S. Mail or e-mail as designated on the Official Service List on file with the Minnesota Public Utilities Commission.

/s/ Roshelle L. Herstein
Roshelle L. Herstein

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414 Nicollet Mall
Minneapolis, MN 55401

December 1, 2011

VIA ELECTRONIC FILING

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: RESOURCE PLAN UPDATE
DOCKET NO. E002/RP-10-825

Dear Dr. Haar:

On August 2, 2010, Northern States Power Company submitted to the Minnesota Public Utilities Commission our Resource Plan for the years 2011 to 2025. We recently requested an opportunity to provide a comprehensive update to the Resource Plan by December 1, 2011. The Commission granted our request through the Notice of Updated Filing and Extended Comment Period on October 10, 2011.

In compliance with the Commission's October 10, 2011 notice, we now submit our Resource Plan Update. As detailed in the Resource Plan Update, we believe continuing to implement many of the initiatives identified in the Original Action Plan is appropriate; however, significantly slower economic growth has delayed the timing of and likely size and type of certain resources. This filing updates our Resource Plan to:

- *Account for slower economic growth and the loss of wholesale customers;*
- *Capture benefits for our customers associated with lower resource needs; and*
- *Inform the Commission of changes to our plans for the current planning cycle.*

We direct stakeholders to the Resource Plan Update – Executive Summary for a high-level discussion of these updates.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission, and copies have been served on all parties on the attached service lists.

Please do not hesitate to contact me at (612) 330-6732 or james.r.alders@xcelenergy.com if you have any questions.

Sincerely,

/s/

JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

Enclosure
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF THE 2011-2025 RESOURCE PLAN	DOCKET NO. E002/RP-10-825 **RESOURCE PLAN UPDATE**

I. EXECUTIVE SUMMARY

A. Introduction

Northern States Power Company submits this update to our Resource Plan to the Minnesota Public Utilities Commission. In compliance with the Commission's October 10, 2011 notice, this filing provides a comprehensive update to our initial Resource Plan, including a revised Five-Year Action Plan designed to cost-effectively meet our customers' needs for electrical energy during the planning period.

As detailed in this filing, significantly slower economic growth has delayed the timing of and likely size and type of our next resource. This filing updates our Resource Plan to:

- *Account for slower economic growth and the loss of wholesale customers;*
- *Capture benefits for our customers associated with lower resource needs; and*
- *Inform the Commission of changes to our plans for the current planning cycle.*

Much of our proposed Five-Year Action Plan remains unchanged and continues to be implemented. This includes our successful effort to achieve 1.5% conservation and demand side management savings. We have also successfully executed our competitive bidding program to add 200 MW of additional wind power to our system and are exploring opportunities for adding wind generation prior to expiration of federal tax incentives, which will likely occur at the end of 2012. However, given the updated information in this filing, we propose the following changes to our initial Five-Year Action Plan:

- *Black Dog Repowering Project*. Our forecasts and refreshed analysis conclude the next generating resource is no longer needed in 2016. We have adequate time to continue monitoring economic conditions and their impact on the timing of our next generation addition. We intend to request withdrawal of the Black Dog Certificate of Need Application, which will be considered separately in the Black Dog Certificate of Need proceeding.

- *Prairie Island Capacity Upgrade Program*. We have made considerable progress toward completing the engineering to support the upgrade of the capacity of the Prairie Island generating plant. Based on current information, we have scaled back our estimate of achievable capacity increases at the plant. Our current base cost analysis suggests the capacity upgrade program remains cost effective. However, given our experience with the Monticello extended power uprate, other utilities' experiences with similar nuclear projects, and the ongoing analysis of regulatory requirements in the aftermath of the Fukushima Daiichi incident, we believe this project would benefit from further review and risk assessment. We recommend the Commission review our analysis in a separate Changed Circumstance docket before we proceed.

- *Wind*. It appears unlikely that the federal production tax credits for wind generation will be renewed at the end of 2012. We plan to reassess our wind power acquisition program after 2012 since we have adequate installed generation and renewable energy credits to maintain compliance with Minnesota Standards for several years.

We believe continuing to implement all other initiatives identified in the Five-Year Action Plan is appropriate.

Finally, we respectfully request that the Commission conclude this planning cycle based on our revised Five-Year Action Plan and schedule the next planning cycle to begin in the Spring of 2013.

B. Need for Resource Plan Update

A Resource Plan begins with a projection of customer demand for capacity and energy over the planning horizon. These projections of future needs serve as the foundation for determining the type and amount of resources that will be needed over the planning period. In developing these projections, we incorporate a variety of information from several internal and external sources. The most important information is fundamental data regarding the status of the economy and projections of economic growth. We also consider other relevant factors. In this case those include new information about nuclear capital investment costs, lower gas prices due to hydraulic fracturing, cost pressures as a result of the events at Fukushima Daiichi and the expiration of the federal production tax credit.

Since our initial filing in 2010, the pace of projected economic growth has changed substantially, and in some cases, is reflecting short-term contraction. As a result, we have reassessed future demand for capacity and energy on our system and our associated resource needs. Our reassessment directly affects the timing (and potentially the size and type) of a key resource investment identified in our initial filing – our proposed Black Dog Repowering Project, which is currently being considered in Docket E002/CN-11-184. Other information, such as our experience with the Monticello extended power uprate and our engineering work to date, suggests it is appropriate to reassess our previously approved Prairie Island extended power uprate ("EPU") to ensure it remains cost-effective. These two projects are discussed in more detail in this filing. Both the Black Dog and Prairie Island projects are at developmental stages where additional review can occur, which will allow us to make the most cost-effective resource decisions for our customers. This filing also addresses the upcoming expiration of the federal production tax credit, the potential for increasing wind generation costs, and our ability to used installed generation and banked renewable energy credits rather than continuing to add wind to avoid higher costs.

While our update is driven by the desire to reexamine a few key capital investments, much of our original Resource Plan and Five-Year Action Plan does not change. Many initiatives included in our Five-Year Action Plan are providing significant value to our customers, even in light of our revised economic and forecast expectations. The remainder of this summary provides additional information about:

- Economic Conditions and Revised Forecasts
- Black Dog Units 3 and 4
- Prairie Island EPU
- Post-2012 Wind Procurement Strategy
- Original Action Plan Initiatives
- Revised Five Year Action Plan

C. Economic Conditions and Revised Forecasts

1. Economic Conditions

The projections for customers' future demands for capacity and energy are highly dependent on several macroeconomic indicators, the three most important being Gross Domestic Product ("GDP"), generally considered the broadest measure of economic activity; Minnesota Gross State Product ("GSP"), which measures the economic output of Minnesota; and Minnesota Households, which generally indicates how many new Minnesota residential customers will be added. When we initially filed our Resource Plan, we projected customers' future demand for capacity and energy based upon economic data from the first quarter of 2010. At that time, both Minnesota and the country overall appeared to be on the path to recovery. Our initial Resource Plan was therefore based upon an expectation of continued steady growth for Minnesota and the overall economy.

Based on the performance of the overall economy, the forecasting companies we rely upon (*i.e.*, Global Insight and others) predicted growth for our key macroeconomic indicators throughout the Resource Plan horizon. For example, at the time of our initial filing, we used the following assumptions for our key macroeconomic indicators:

Indicator	**Initial Resource Plan Projection**
2011/2012 Average GDP Growth Rate	3.3%
2011/2012 Average Minnesota Gross State Product Growth Rate	2.8%
2011/2012 Average Minnesota Household Growth Rate	1.1%

Source: Global Insight

After we submitted the initial Resource Plan, underlying economic conditions began to change. Nationally, growth decreased over the second half of 2010, registering slightly above 2 percent growth for the remainder of the year. In response to continued slower than expected economic performance, forecasters have continued to revise each of our key macroeconomic indicators downward, including for Minnesota:

Indicator	Initial Resource Plan	Black Dog CON Update	Updated Resource Plan
2011/2012 Average GDP Growth Rate	3.3%	2.6%	2.2%
2011/2012 Average Minnesota Gross State Product Growth Rate	2.8%	2.6%	1.7%
2011/2012 Average Minnesota Household Growth Rate	1.1%	1.1%	0.9%

Source: Global Insight

The downward revisions have not been limited to future expectations of macroeconomic performance; estimates of actual results have also been reduced. For example, in August 2011, the U.S. Bureau of Economic Analysis substantially revised its estimate of actual GDP for 2007 through the first quarter of 2011.

Bureau of Economic Analysis[1] Annual Revision of the National Income and Product Accounts		
	Original Estimate	Revised Estimate
2007–2010 Average Real GDP Annual Rate of Change	>(0.1)%	(0.3)%
Fourth Quarter 2007 – First Quarter 2011 Average Real GDP Rate of Change	0.2%	(0.2)%

While it is not uncommon for historical indicators to be revised, these revisions are unique in that they change the overall direction – from growth to contraction – and revise declining numbers downward further. Because both forward-looking and backward-looking macroeconomic indicators play such an important role in our projections of customers' future needs, these revisions necessitated an update to our forecasts.

We updated our forecasts in the Spring of 2011 based upon the then-existing macroeconomic expectations. This forecast indicated some softening of the overall economy, but still showed overall growth in our customers' requirements. On June 14, 2011, we provided an updated projection of our customers' demand for capacity and energy in our Black Dog Repowering Project Certificate of Need proceeding ("Black Dog CON"). This projection showed lower demand for capacity and energy than what was included in our initial Resource Plan. Our revised projection reflected

[1] BUREAU OF ECONOMIC ANALYSIS, *Annual Revision of the National Income and Product Accounts* at 6 (Aug. 2011), *available at* http://www.bea.gov/scb/pdf/2011/08%20August/0811_nipa_annual_article.pdf.

a combination of reduced firm wholesale municipal load, lower actual peak demand in 2011, and updated macroeconomic performance indicators. We also noted in the June update that if the economy showed further signs of weakness, it could cause us to change our recommendations. We committed in that filing to continue to closely monitor the situation and provide the Commission with additional updates as circumstances evolved.

Since we provided these projections in the Black Dog CON proceeding, the economy has continued to soften. In particular, the key macroeconomic indicators we rely upon in projecting customers' future demand for capacity and energy have been revised downward to show:

- Lower Minnesota industrial production;
- Slower recovery of commercial and industrial load;
- Lower Minnesota employment growth for 2011 and 2012; and
- Lower housing permits for 2011 and 2012.

We now expect 0.7% annual demand growth and 0.5% annual energy growth over the Resource Plan horizon, down from 1.1% and 0.9%, respectively, included in our initial filing. The magnitude of the reduced forecast is such that it prompts us to reconsider some components of our Five Year Action Plan. Thus, this update presents our new sales forecast and provides the Commission with recommendations on some revisions to our plans going forward.

2. Revised Forecast

Our current expectations are lower than what was included in the initial filing, reducing our projection of customers' future demand for capacity in 2016 by approximately 500 MW from our initial Resource Plan filing. These new expectations impact the timing and type of required generation additions. In light of our revised expectations, we currently have sufficient generation resources to meet customers' needs through 2018. Accordingly, we will seek authorization in other proceedings to withdraw our currently-pending application for repowering of Black Dog Units 3 and 4 and ask the Commission to reevaluate the planned EPU at Prairie Island.

D. Drivers for this Filing

1. Black Dog Units 3 and 4

We have continued to assess the repowering of Black Dog Units 3 and 4. Based on the revised economic outlook, we no longer expect a 2016 capacity deficit. As such, we do not believe it is necessary to pursue the repowering of Black Dog Units 3 and 4 for a 2016 in-service date. Instead, it provides more value to our customers to delay the repowering and rely upon existing generation to meet our needs.

We do not expect additional generation will be needed on our system until 2018. As a result, we have time to continue assessing the best resource addition options for our customers. Deferring the capital investment required for the repowering (or delaying the proposed alternative) will save our customers money and is the best course of action at this time. Through a separate filing in our Black Dog CON proceeding, we will request authorization to withdraw our application for approval of the Black Dog Repowering Project.

To date, we have performed significant preliminary development and permitting work on Black Dog and believe that work will have continuing value. These efforts were appropriate in order to develop and advance the certificate of need proceeding and to be prepared for implementing the project in a timely manner, if approved. We have also reasonably incurred costs to plan and develop the Black Dog project. We will address preserving those costs for recovery in another docket.

2. Prairie Island EPU

Since our initial Resource Plan filing, changes have occurred regarding our EPU at Prairie Island. Based on our experience with the EPU project at the Monticello Nuclear Generating Plant, other utilities' recent experiences with EPUs, and the Nuclear Regulatory Commission's ("NRC") review of post Fukushima Daiichi issues, we believe the most prudent course of action is to consider the appropriateness of continuing to pursue the EPU at Prairie Island. We plan to initiate such review in a separate docket through a Changed Circumstances Filing in 2012.

We addressed the additional costs related to the life-cycle management ("LCM") and EPU work for Monticello as a part of our currently-pending electric rate case. Some of the additional costs stem from the fact that actual implementation of EPU/LCM at Monticello is more labor and capital intensive than we initially estimated. We are considering the risk of similar developments in our EPU at Prairie Island.

As part of this filing, we have made a preliminary reassessment of the cost effectiveness of the EPU program for Prairie Island based on changes known at this time. To date we have gained an additional 18 MW of generation at Prairie Island through work already authorized by the NRC. Additionally, significant project engineering work has been advanced and we recently received bids from vendors for various parts of the LCM/EPU program at Prairie Island. Based on our engineering work and review of bids, we are evaluating capital costs and performance of various components of the EPU program at Prairie Island. Our current base cost analysis indicates only 117 MW of the remaining 146 MW of generation that was originally expected to be added as a result of the EPU should be pursued if it continues to be cost effective.

Finally, as EPU licensing has evolved and in light of the impacts of Fukushima Daiichi, the NRC is currently considering additional application requirements. It is also assessing whether to require additional improvements to address accident analyses, which may expand the scope of current EPU projects. An example of this additional review was noted by the Company in our November 22, 2011 Changed Circumstances Filing for the Monticello EPU. Although Prairie Island is a different design, and should be less affected than Monticello, we believe NRC review will be longer than anticipated. Thus, we are assessing the risk of further cost increases.

Before we proceed further with the Prairie Island EPU project we believe it would be appropriate to present our analysis of all of these issues in more detail through a Changed Circumstances Filing. This will provide an opportunity for the Commission and other interested parties to understand the current cost projections for the LCM/EPU project, reassess the risks of EPU investment, and determine whether the Prairie Island EPU continues to be in the public interest given all considerations. In the meantime, we plan to carry out our LCM program at Prairie Island, with various activities that support the additional 20 years of licensed operations and fuel storage recently approved.

E. Post-2012 Wind Procurement Strategy

Consistent with our initial filing, we issued a Request for Proposal ("RFP") for up to 250 MW of wind energy to be in service by the end of 2012 on September 16, 2010. We are pleased to report that this RFP process was a significant success.

We received 143 proposals on 106 sites comprising 9,189 MW of distinct resources. As a result of that successful process, we entered into a power purchase agreement ("PPA") with Geronimo Wind Energy for the 200 MW Prairie Rose Wind Farm, which was approved by the Commission on November 10, 2011.[2] The Prairie Rose transaction also includes an option for the Company to take an additional 100 MW of generation, subject to Commission review and approval, providing us with the flexibility to capture additional generation if market conditions warrant.

[2] *See* Docket No. E002/M-11-713.

As evidenced by the bids we received in this RFP, wind developers significantly reduced the price of project proposals in 2011. The decrease relates in part to lower project development costs, but also significantly reflects the impact of the pending expiration of the federal Production Tax Credit ("PTC"). The PTC significantly reduces the cost of wind generation, without which it may not be a cost-effective investment. However, the PTC is set to expire at the end of 2012 and extension appears unlikely at this point. Thus, post-2012 wind projects may be significantly more expensive if they are unable to rely upon the availability of the PTC.

We have explored the opportunity to procure low-cost wind generation between now and the expiration of the PTC, but the short timeframe also created significant construction, permitting and financing challenges. The Company will continue to explore opportunities to procure as much as 300 MW of additional wind generation prior to the PTC expiring. While we are eager to obtain low priced, cost-effective wind generation for our customers, we seek to avoid the risks of incomplete or failed projects. We will, of course, report to the Commission if we are successfully able to contract for additional wind generation prior to the PTC deadline.

Currently we have significant installed generation and a bank of renewable energy credits that we can use to satisfy our renewable energy requirements. To the extent the PTC expires and wind prices increase as expected, we will be able to rely on our installed generation and banked RECs rather than adding uneconomic wind generation. Drawing upon our installed generation and banked RECs will allow us to wait for the market to settle and reevaluate market conditions in our next Resource Plan filing. This allows us to evaluate market conditions and acquire wind only if it is a cost-effective resource for our customers. Thus if prices do not spike or cost-effective opportunities become available, we may add wind generation. In this update, we have modeled various wind scenarios to reflect our options. Our revised Five-Year Action Plan reflects that we will not add more wind generation after 2012 unless it is cost-effective for our customers.

F. Contingency Planning

In previous resource plans, we discussed a contingency process to address the potential for more rapid capacity expansion than envisioned in a five-year action plan. Although this update proposes that it is appropriate to delay a significant capital investment at Black Dog due to slower economic growth, the market volatility and the potential for a faster economic rebound should be considered as well. There have been signs of a strengthening economy at various times over the past two years and we certainly desire that more robust economic growth materializes. In the event of faster growth, we can always rely on the energy market to meet short term needs;

however, it is also important to consider a contingency that adds a physical resource to avoid being overly reliant on the market. We believe it is time to enhance contingency planning by considering opportunities for developing engineering, permitting, and equipment reservations for physical generation. For instance, this could allow us to modify the work undertaken to date for the Black Dog project. Such a discussion of appropriate contingency mechanisms could also address appropriate rate mechanisms to encourage advance preparation. Overall, a contingency process would provide customers an important hedge against exposure to market conditions and allow us to continue appropriate long-term planning activities.

G. Conclusion

The proposed, revised Five-Year Action Plan provides relevant updated information to reflect changes that have occurred since we originally filed our Resource Plan in 2010. As a result of this update, we believe certain key investments should be delayed or reviewed, while the remainder of our Five-Year Action Plan continues. The key changes allow us to maximize benefit for customers and ensure that we meet their needs in a cost-effective manner. By implementing the changes discussed above, our revised Five-Year Plan delays significant capital expenditures until additional resources are needed on our system. Meanwhile, elements of our Plan continue to be prudent and have already delivered substantial customer value.

Therefore, we ask the Commission to conclude this planning cycle by approving our revised Five-Year Action Plan, including the following changes from our initial proposed Five-Year Action Plan:

- Withdrawal of our Black Dog Repowering Project, to be assessed in a separate docket;
- Additional assessment of the Prairie Island EPU, to be conducted in a separate docket;
- Our revised post-2012 wind procurement strategy; and
- Further development of a contingency plan.

We also ask the Commission to approve as part of our revised Five-Year Action Plan those portions of our initial Five-Year Action Plan that are already providing value to our customers, including:

- *DSM.* In 2010, we significantly exceeded our DSM goals, achieving 415 GWh in savings, which translates into 1.35% of sales. As part of our initial filing, we indicated we wanted to expand our savings goals to 1.5% and we are on track to exceed that goal for 2011. DSM continues to deliver value for our customers and we are excited to continue working with our stakeholders to achieve 1.5% DSM energy savings as part of the revised Five-Year Action Plan.

- *Manitoba Hydro*. On May 26, 2011, the Commission approved three previously identified agreements with Manitoba Hydro.[3] Extending our relationship with Manitoba Hydro will allow us to continue providing customers with economical service from renewable resources.

- *Monticello EPU*. We continue to include the EPU at the Monticello as part of the revised Five Year Action Plan.

- *Wind*. We have successfully procured 200 MW of wind power pursuant to the RFP process and we are exploring other wind opportunities for 2012 completion.

Finally, we request that the Commission authorize the Company's next planning cycle to begin in the Spring of 2013.

II. REVISED FORECAST AND RESOURCE NEEDS

The process of resource planning is an important step in achieving our goal to provide our customers with safe, reliable, cost-effective service. As part of our Resource Plan, we engage in a forward-looking process to assess both our customers' electric needs and the resources required to meet those needs.

Resource planning is an ongoing task and many variables affecting resource needs can change over a planning horizon.

The country entered an economic recession in early 2008 that lasted eighteen months. Due to the volatility in the economy and its impact on customers' future energy needs, we have updated our analysis of demand for capacity and energy on our system.

When we filed our initial Resource Plan, we recognized the economic environment at that time, which could further change, and the affect this may have on our customers' future energy needs. We therefore committed to monitor the economic environment. In subsequent months we assessed the impact of revised historic and forward-looking data and updated our forecasts. This past June, we provided our first forecast revision

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[3] *See* Docket No. E002/M-10-633.

to the Commission and other interested stakeholders as part of the Black Dog CON proceeding. We now provide our most recent forecasts and the data that supports our analysis.

While we propose modifications to our Resource Plan to account for current economic conditions, we recognize the economy is still volatile. We therefore remain committed to monitoring the economic environment and analyzing its impact on our resource needs. As we learn more about the economic conditions affecting the country, we will continue to adjust our projections as often as is needed to assure that we prudently manage our business and resources for the benefit of our customers.

The remainder of this section presents the data supporting our revised forecasts and our current projection of customers' future demand for capacity and energy. First, building upon the information included in the Executive Summary, we provide data which confirms that the economy did not, and likely will not, grow as we believed it would when the initial Resource Plan was filed. Next, we discuss an additional driver that further lowers our demand forecasts. We then provide our revised forecasts and explain the impact the downward adjustment will have on our resource needs.

A. Changed Economic Expectations

Prior to filing our initial Resource Plan, key economic indicators suggested that our country was emerging from the 2008 recession. As early as April 2009, forecasters were predicting GDP would grow by approximately 3.2 percent in 2010 and 3.6 percent in 2011. Though actual results for the fourth quarter of 2009 showed a slight decline, forecasts developed throughout the first half of 2010 continued to show moderate GDP growth for 2011 and 2012. Long-term economic indicators projected similar growth for the economy throughout this Resource Plan horizon. As a result, we based our initial Resource Plan upon an expectation of continued steady growth of approximately 2.5 percent for Minnesota and the overall economy between 2011 and 2018.

Based on the key macroeconomic indicators discussed in the Executive Summary and other relevant information, we forecasted 1.1% annual growth in system peak demand and 0.9% annual growth in median net energy in our initial Resource Plan filing. We also presented a limited Five-Year Action Plan which included, among other things, issuing the RFP for 250 MW of wind power, the Black Dog Repowering Project, the Prairie Island EPU project, and on-going evaluation of options for addressing potential peaking resource needs in the immediate future. We recognized, however, that our forecasts could be subject to change if the country's economic recovery did not materialize as experts predicted.

After our initial Resource Plan was filed, economic experts throughout the country determined that the recession was more severe than initially understood and the country was recovering at a slower rate than expected. Forecasters revised several key economic indicators downward, with Minnesota being hit hard:

Indicator	Initial Resource Plan	Black Dog CON Update	Updated Resource Plan
2011/2012 Average GDP Growth Rate	3.3%	2.6%	2.2%
2011/2012 Average Minnesota Gross State Product Growth Rate	2.8%	2.6%	1.7%
2011/2012 Average Minnesota Household Growth Rate	1.1%	1.1%	0.9%

Source: Global Insight

As explained in the Executive Summary, economists also began revising historic indicators downward. For example, in August 2011, the U.S. Bureau of Economic Analysis substantially revised its estimate of actual GDP, as measured from 2007 through the first quarter of 2011.

Though these changes were substantial, many of the strategies outlined in our Resource Plan still appeared to be necessary. The new economic data, however, could potentially justify delaying certain projects, which would mitigate short-term rate impacts. We first communicated our understanding about the impact slower economic growth was having on our demand forecasts to the Commission and other interested stakeholders in the Black Dog CON docket. On June 14, 2011, we provided an updated projection of our customers' future demand for capacity and energy. After using actual 2010 weather-normalized peak demand and the best economic data available at the time, our 2011 forecast for median peak demand was approximately 175 MW lower than what was included in our initial Resource Plan filing. Instead of the expected steady economic growth, we observed lower demand for capacity and energy due to a continued softening of the overall economy.

The June filing also addressed that all of our Wisconsin municipal wholesale customers and all but one of our Minnesota municipal wholesale customers decided not to renew their service agreements. This represents a 229 MW reduction in demand by 2014. We committed to closely monitor our expectations of our customers' future needs, as further changes could cause us to modify our recommendations relating to future resources.

B. Revised Forecast

Unexpected setbacks to the country's economic recovery and more significant wholesale municipal customer attrition have substantially changed our expectations for future resource needs. In response, we revised our forecasts for this Resource Plan, using the same key demand and forecast variables and forecast methodology as was described in our initial Resource Plan filing.

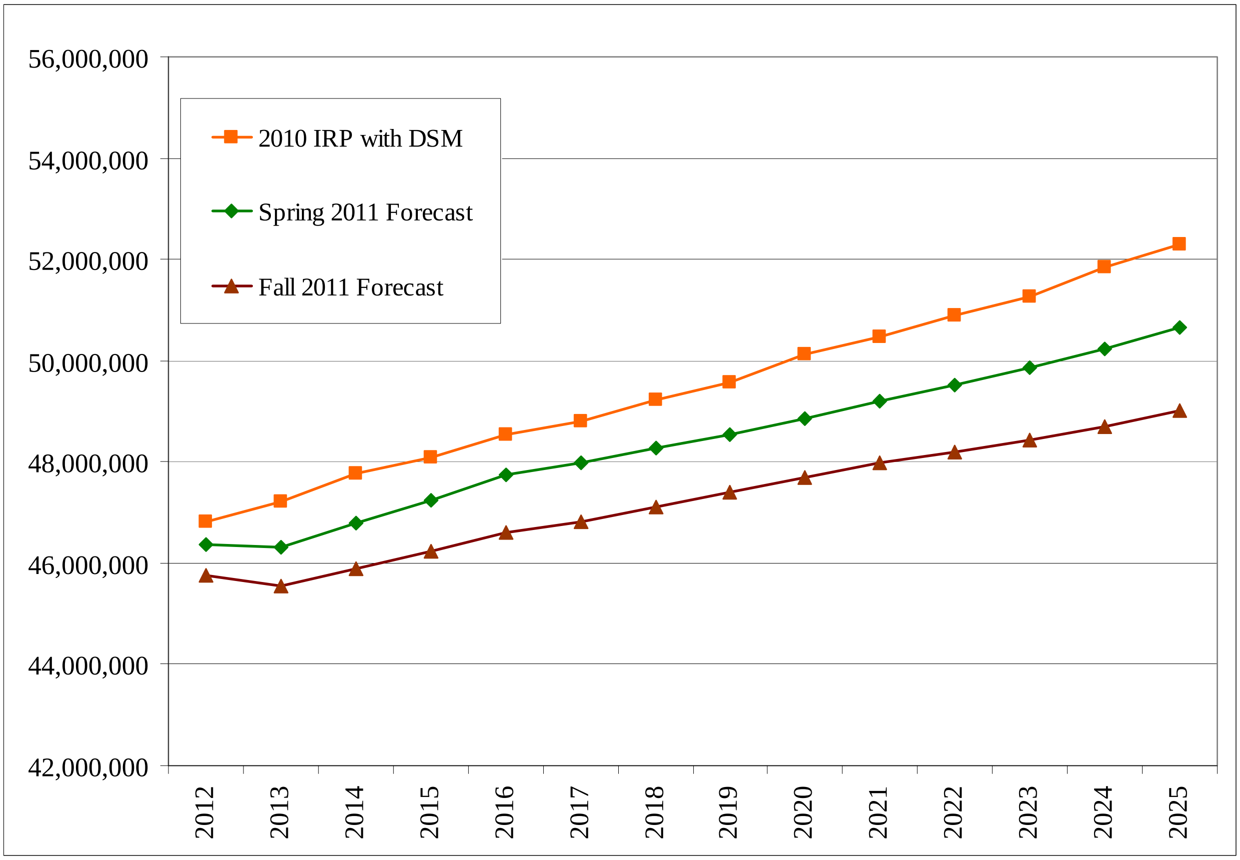
1. *Comparison of System Peak Demand and Median Net Energy Forecasts*

The table and graphs below illustrate the progression of our system peak demand and median net energy forecasts over time.

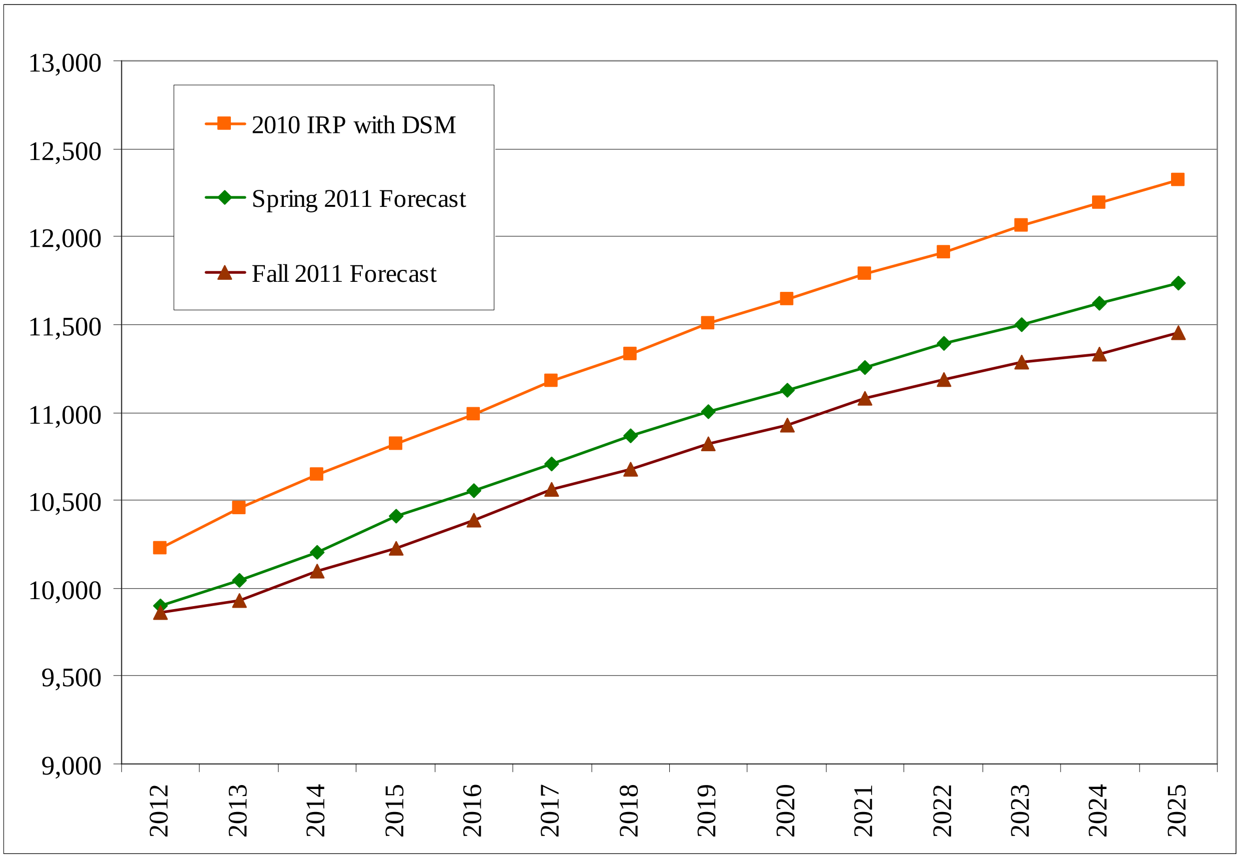
Forecast	**Annual Growth in System Peak Demand**	**Annual Growth in Median Net Energy**
Initial Resource Plan (June 2010)	1.1%	0.9%
Black Dog CON Update (June 2011)	0.9%	0.7%
Resource Plan Update (September 2011)	0.7%	0.5%

A comparison of the three forecasts is also shown in revised Figures 3.6 and 3.7 below.

Revised Figure 3.6
Net Energy Requirements (MWh)
Median (50th Percentile) Forecast
Comparison of Current and Previous Energy Forecasts



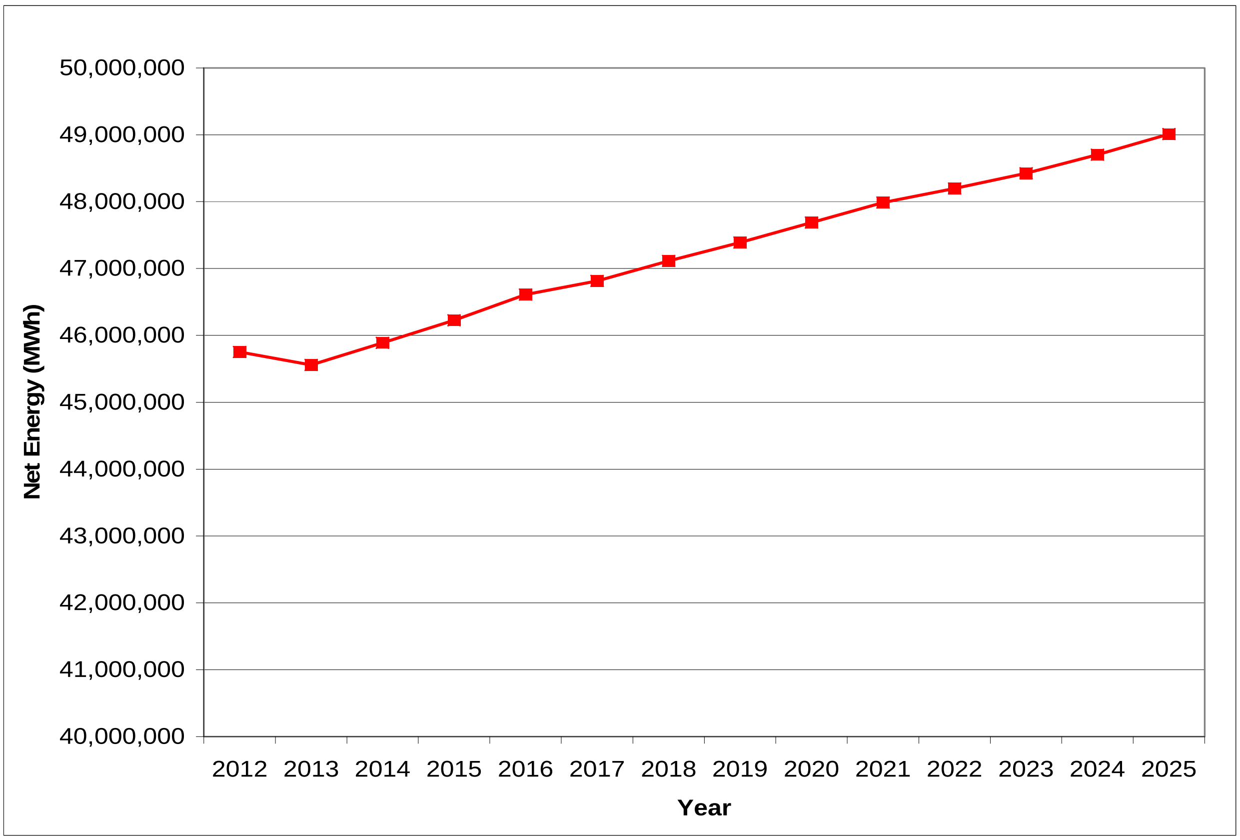
Revised Figure 3.7
Base Peak Demand (MW)
90th Percentile Forecast
Comparison of Current and Previous Demand Forecasts



2. Base Energy Forecast

In light of current information, we now expect our customers' demand for energy to increase at an average annual growth rate of 0.5% between 2011 and 2025. This compares to our original forecast of an average annual growth rate of 0.9%. The revision is based on an expected change in the annual average increase of electric energy requirements. See Revised Figure 3.1 below.

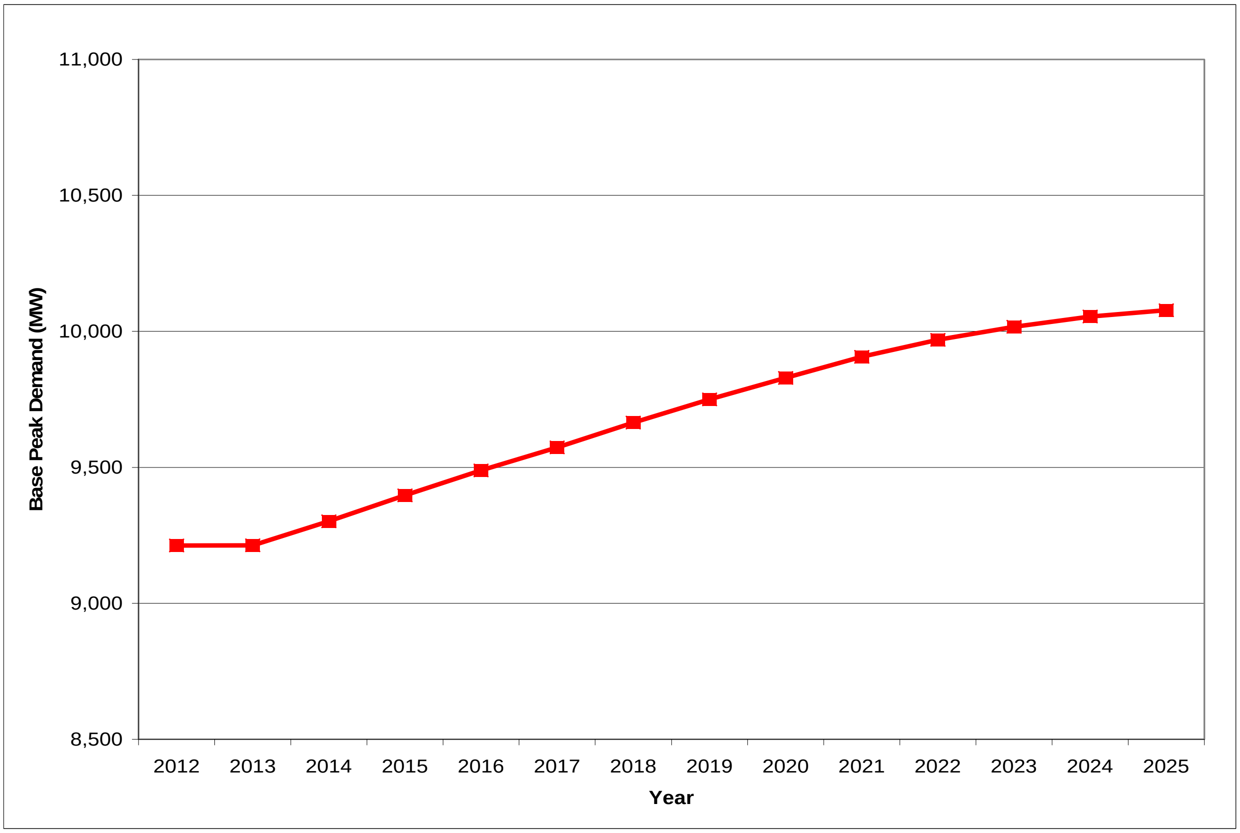
Revised Figure 3.1
Median Net Energy (MWh) NSP Total System
(Includes 1.5% Retail Sales DSM Adjustment)



3. System Peak Demand Forecast

Our updated base peak demand forecast, which reflects conservation efforts through 2010 but not the Company's load management programs, now projects 0.7% average annual growth in median base peak demand. This compares to our original forecast of an average annual growth rate of 1.1%. Over the planning period, annual peak demand now increases at a lower rate each year in the revised forecast.

Revised Figure 3.2
Median Base Summer Peak Demand (MW) NSP Total System
(Includes 1.5% Retail Sales DSM Adjustment)



4. *Forecast Variability*

To assess the potential variability embedded in our forecasts, we developed probability distributions for the peak demand and energy requirements using the same methodology discussed in our initial Resource Plan. Based on Monte Carlo simulations, there is now a 90% probability that the net energy will be less than 53,406,963 MWh in 2025. There is only a 10% probability that the net energy will be less than 44,622,960 MWh. While these probabilities are intended to bolster confidence in our forecasts, prudent planning always requires us to retain flexibility in our resource portfolio so we can address scenarios which may or may not unfold.

C. Affect on Resource Needs

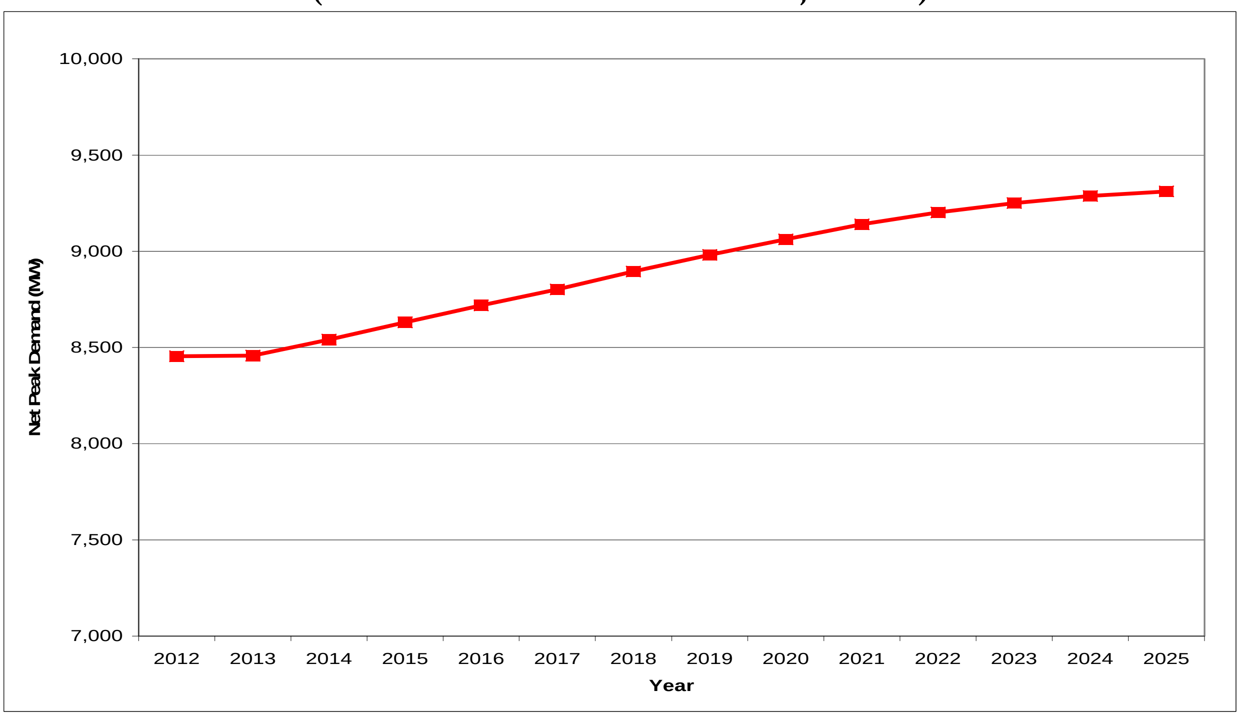
While many of the resources outlined in our initial Resource Plan are still needed, the discussion below explains our resource needs in light of our revised forecasts.

1. *Total Load Obligation*

As part of the initial Resource Plan, we provided a detailed discussion regarding the methodology and general assumptions used to develop our resource needs. For purposes of this update, our methodology and assumptions, except for those that changed as a result of slower economic growth and the departure of Wisconsin and Minnesota municipal customers, remain the same.

Our updated median net peak demand forecast increases at an average annual rate of 0.3% over the 2011 – 2025 planning period, which compares to an average annual rate of 1.2% that was forecasted as a part of our original filing. Additionally, the revised net peak demand forecast increases at an average of 31 MW annually. See Revised Figure 3.8 below.

Revised Figure 3.8
Medium Net Summer Peak Demand NSP System
(Includes 1.5% Retail Sales DSM Adjustment)



2. *Supply Resources*

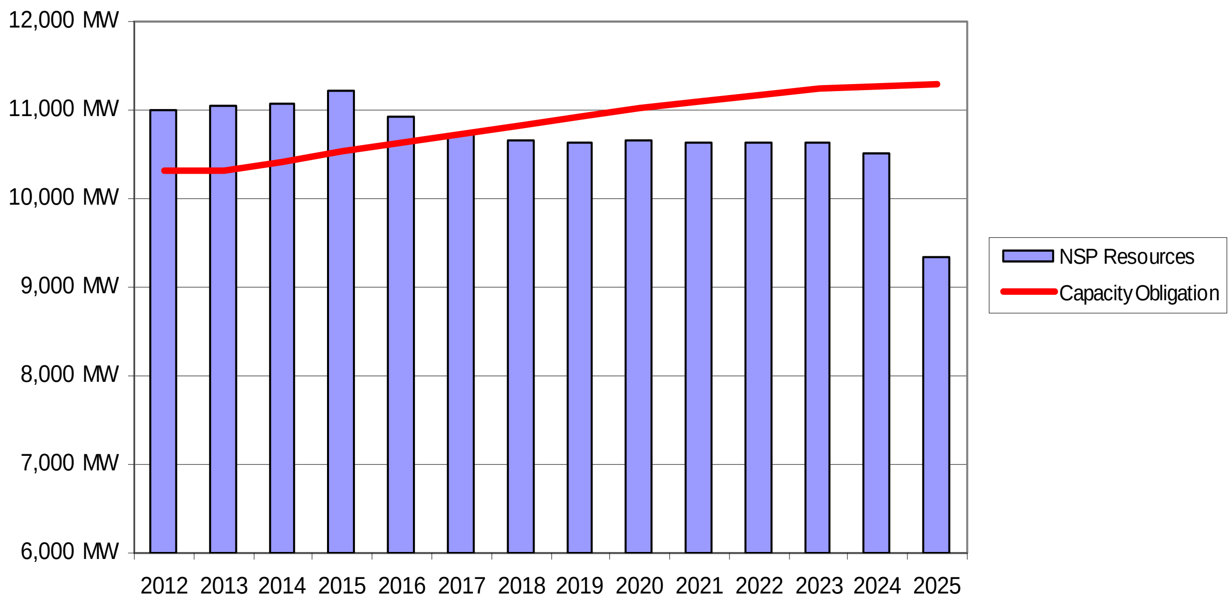
Based on our updated forecasted demand and expected available resources discussed above, we now anticipate new production capacity will be needed starting in 2018. This is three years later than indicated in our initial filing and provides us with additional time to assess the appropriate resources to fulfill our customers' needs.

The delay in timing of the need for new production, and the delay in incurring additional costs, benefits our customers.

3. Generation Requirements

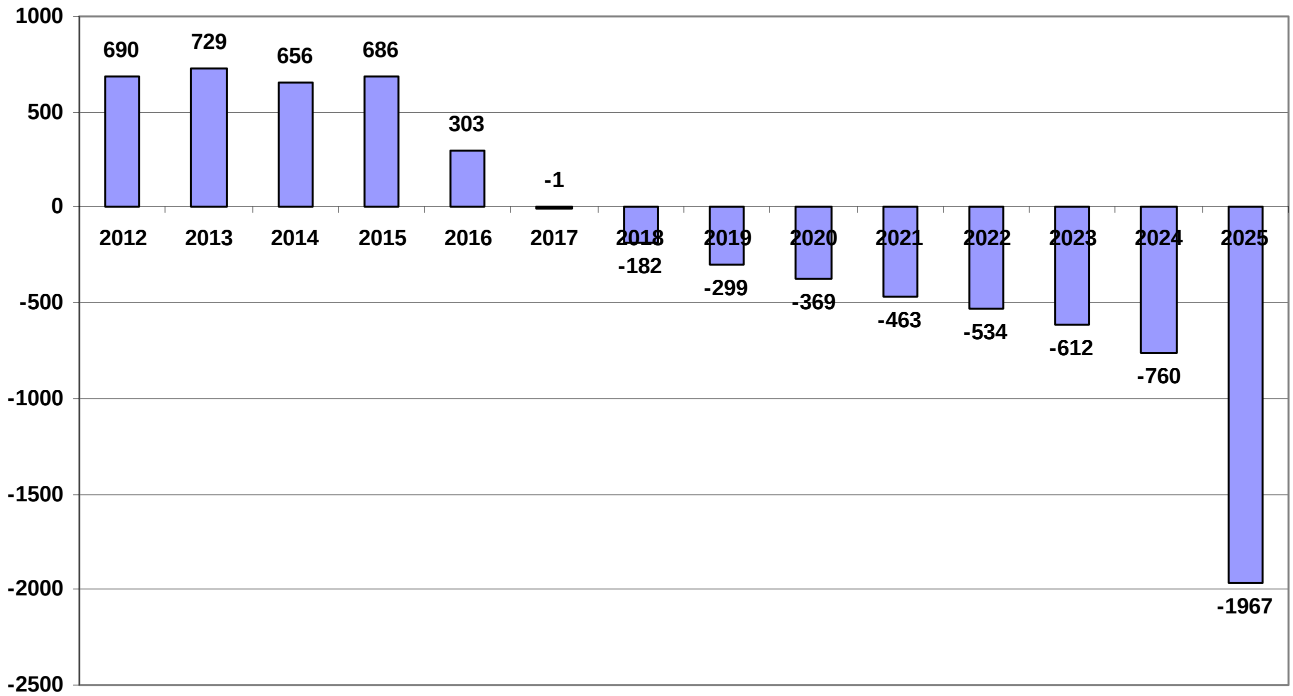
Revised Figure 3.10 presents an updated comparison of our forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions.

Revised Figure 3.10
Requirements and Resources 2011-2024



Revised Figure 3-11 shows our projected resource needs for the planning period.

Revised Figure 3.11
Resource Needs by Year



In our initial filing, we expected to have surplus generation through 2013 with a deficiency emerging in 2014. As shown above, we now expect to have a surplus through 2016 with a deficiency emerging, in earnest, in 2018.

While the resource needs discussed above reflect our best assessment of our customers' future demand for capacity, uncertainty still exists. The pace of economic recovery remains uncertain, and as a result, our expectations may continue to change over the next several years. Thus, we believe it is important to consider a contingency process that allows us to be prepared to add capacity quickly in the event economic recovery occurs stronger and faster than currently anticipated. In that event, we want to be prepared to cost-effectively meet capacity and energy needs of our customers.

D. Conclusion

Resource planning is a continual process in which we address our customers' future needs in a cost-effective manner. Our customers' needs, however, can change depending on multiple factors, including the strength of the economy. Our initial Resource Plan was developed against a back-drop of an economic recession coupled with a volatile recovery. At the time, we appreciated the potential for this uncertainty and therefore have monitored key economic indicators. We now expect growth in demand of 0.7% per year and growth in energy of 0.5% per year over the 15-year planning period. The predicted rates assume we maintain DSM savings at 1.5% of retail sales. Comparing our projections to our available resources, we anticipate a need for additional generating resources starting in 2018. The delay in timing of new resources to meet our customers' needs allows us to defer additional capital costs.

III. MODELING AND PLAN DESCRIPTION

A. Baseline Assumptions

Our base assumptions are similar to those used in the initial Resource Plan filing, updated for current values:

Forecast

We plan to meet the 50% probability level of forecasted peak demand, and the 50% probability level of forecasted energy requirements.

Existing Fleet

- Cost and performance assumptions are consistent with historical data.
- Costs are escalated based on corporate estimates of expected inflation rates.
- Continued operation of our Sherco[4] and King generating stations throughout the study period.
- Retirement of our Prairie Island nuclear generating station at the end of its proposed license renewal (2033, 2034), and retirement of Monticello at the end of its current license (2030), and for the purposes of this planning document and analyses, replacement with new nuclear generation.
- Retirement of other facilities at their current expected end of life if within the Resource Planning period, unless we have specifically included costs of life extension.[5]
- Continuation of our existing power purchase contracts until their contractual termination dates.

[4] As noted in this update, we are investigating a recent incident at Sherco Unit 3. At this time we are not proposing any change to our Resource Plan because of this incident and consequently have not changed the way we model this generation.

[5] The one exception to this assumption is with regard to our Sherco Units 1 and 2. These facilities reach the end of their book lives in 2023. However, we are initiating a life extension study for these units, and are assuming, for the purposes of this analysis, that they continue to operate beyond 2023.

- Continued operation of our hydroelectric resources based on historical performance.

Renewable Energy

- Expiration of the PTC at the end of 2012.
- No additional wind generation added to the system after 2012, with a sensitivity to add 900 MW of wind generation between 2013 and 2020.
- Accreditation of wind resources based on Midwest Independent System Operator, Inc. planning reserve credit allocation (currently 12.9%).
- Additional ancillary service charges for wind based on the 2006 Minnesota Wind Integration Study.

Emissions

- Emission rates for existing and planned resources consistent with historical and expected performance.
- Cap and trade permit systems for SO_2, and NOx.
- No costs for carbon dioxide, but with sensitivities for CO2 values at the Commission's mid- and high-level estimates, plus a "late" CO2 scenario with costs starting in 2018.
- We did not incorporate the Commission's externality values for specified emissions as a base assumption, but included those high and low externality values as sensitivities.

We also updated the costs of our generic units. A list of our current assumptions is included in Attachment A.

In developing the updated proposed Five Year Action Plan, we analyzed several components to determine their cost effectiveness. As discussed in this update, we are assessing the Prairie Island EPU program given updated costs and potential delay scenarios. We also reanalyzed our need for the Black Dog Repowering Project, testing this project in several different years and optimizing the model to determine the timing and resource under a number of scenarios. As in the initial Resource Plan, we also updated scenarios that did not include our wind expansion plan, and scenarios that meet our North Dakota and South Dakota requirements.

B. Updated Proposed Five-Year Action Plan

Our updated plan builds on elements from the initial Resource Plan by including the following components:

- Completing the capacity uprate project for Monticello;
- Proceeding with EPU project for Prairie Island, subject to the outcome of our forthcoming Changed Circumstance filing;
- Withdrawing our request for a Certificate of Need for the Black Dog Repowering Project and reassessing the timing and need for additional combined cycle generation as part our next resource planning cycle;
- Retiring existing Black Dog Units 3 and 4 by 2016;
- Adding new combustion turbines to our system beginning in 2018;[6]
- Optimizing capacity additions for the remainder of this resource planning period;
- Flexible timing of wind additions and using installed generation and existing RECs to ensure the best value to our ratepayers; and
- Building our DSM programs to sustain savings of 1.5% of annual sales.

Updated Table 4.1 summarizes the expansion plan for the base scenario.

Table 4.1
Proposed Plan Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulv. Coal	Wind
		Generic Additions			
2011					
2012	Wind 32 MW				
2013	Wind 32 MW				
2014					
2015	PI EPU 58 MW MH 375 MH 350				
2016	PI EPU 58 MW				
2017					
2018			195 MW		
2019			195 MW		
2020			195 MW		
2021	MH 125				
2022					
2023			195 MW		
2024			195 MW		
2025		729 MW			

[6] The Strategist modeling shows a capacity need in 2018. At this point, however, the modeling does not establish a clear preference for the type of generation that best meets that need. As a result, we propose to continue to monitor and update our assumptions, and identify the most reasonable resource for 2018 in our next Resource Plan, which we are proposing to commence in Spring 2013.

As discussed in this update, we have significant installed capacity and RECs to meet the Minnesota renewable energy standard. This gives us considerable flexibility with respect to the amount and timing of wind generation that needs to be installed over this resource planning period. We are also concerned the PTC benefit will expire at the end of 2012 and not be renewed. As a result, our base case model does not add any incremental wind projects beyond 2012, pending a better understanding of the economics of the post-2012 wind market. For comparison purposes, we have also modeled a sensitivity in which we install 900 MW of wind between 2013 and 2020, based on our current estimates of post-2012 wind pricing assuming the PTC is not extended.

C. Sensitivity Analysis

To determine how changes in our assumptions impact the costs or characteristics of different plans, we examine our plans under a number of scenarios as described on page 4-9 of our initial Resource Plan. We used the same sensitivity scenarios as were included in the original filing, except as specifically described above.

Updated Table 4.2 shows the PVRRs of the proposed plan under the base assumptions and various sensitivity tests.

Updated Table 4.2
PVRRs of Proposed Plan and Sensitivities

	PVRR ($millions)	Difference from Base
Base Assumptions	$78,199	$0
High Gas + 20%	$79,436	$1,237
Low Gas -20%	$76,915	($1,283)
Low CO2 $9/ton 2012	$81,727	$3,529
Mid CO2 $17/ton 2012	$84,826	$6,627
High CO2 $34/ton 2012	$91,139	$12,940
Late CO2 3 Source Blend	$83,121	$4,922
High Load	$80,978	$2,779
Low Load	$75,096	($3,103)

Under the "low load" sensitivity, Strategist does not add new resources until 2025. Under the "high load" sensitivity, Strategist suggests that we would need to consider adding combined cycle generation instead of combustion turbine peaking units, and potentially bridge a 2017 resource need with short-term capacity or a combustion turbine. While we do not consider this scenario as likely, the additional generation selected by Strategist under this sensitivity highlights the value in having a specific, implementable contingency generation plan available to us to deal with changes in the forecast. Our proposed contingency plan is discussed later in this update.

Minnesota Statute § 216B.2422, subd.3, requires that we consider the environmental cost values for various emissions established by the Commission. Updated Table 4.3 shows how incorporation of those values affects the PVRR for the proposed Five Year Action Plan.

Updated Table 4.3
PVRRs of Plan w/ Commission Externalities

	PVRR ($millions)	**Difference from Base**
Base Assumptions	$78,199	$0
High Externalities	$80,064	$1,865
Low Externalities	$78,488	$290

D. Scenario Analysis

To address issues that have been raised since we filed our 2007 Resource Plan, we developed two additional set of scenarios – the "North Dakota/South Dakota" ("ND/SD") scenario and the No New Wind/Full Wind Scenario. The ND/SD scenario has been developed pursuant to settlements with North Dakota and South Dakota in our most recent general rate cases in those jurisdictions. The No New Wind/Full Wind scenarios have been developed based on our requirement pursuant to Minn. Stat. §216B.1691, subd. 2e, to update information on the rate impacts of complying with the RES.[7]

[7] *See* Docket No. E999/CI-11-852.

1. ND/SD Scenario

As with our initial Resource Plan, our ND/SD scenario was designed around the environmental and renewable policies in North Dakota and South Dakota. Both jurisdictions have similar policies, so we developed a single scenario designed to meet but not exceed federal, North Dakota, and South Dakota environmental and renewable requirements as they currently exist. In this update, we include the same set of assumptions and variations used in the initial Resource Plan, except that we included the impacts of Minnesota conservation and demand-side management in our base case.

In this update, the ND/SD scenario differs from our updated plan only in that we allow a supercritical pulverized coal facility ("SCPC") without sequestration to be selected in the ND/SD scenario, and not in the updated plan. We believe it would be difficult to permit such a facility, and as a result we do not consider it a viable option for our resource plan; however, one could potentially be added under North Dakota and South Dakota law. In our August 2010 filing, our modeling of the ND/SD scenario resulted in the selection of three SCPC coal plants in the expansion plan. In this update, the ND/SD scenario is identical to the base case. The change in resources between the August 2010 filing and this update results from a combination of higher capital costs for coal plants, lower capital costs for combined cycle and combustion turbine plants, lower gas prices and lower forecasted load in the current model.

Our updated analysis of the ND/SD Scenario shows that our proposed plan is a reasonable plan, even when we consider it in light of the different policy approaches that North and South Dakota use.

2. No New Wind/Full Wind Scenarios

Consistent with the requirements to consider the cost impacts of meeting the RES, as well as our own goals to maintain a cost-effective and diverse resource mix, we have modeled a scenario assuming full compliance with the RES in 2020 and beyond. Our model assumes that the PTC is not extended beyond 2012 and that wind prices start at current cost levels and escalate at approximately 2% per year. The full wind expansion plan includes the following resources through 2025:

Updated Table 4.8
Full Wind Scenario Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulverized Coal	Wind (Accredited)
		Generic Additions			
2011					
2012	Wind 32MW				
2013	Wind 32 MW				13 MW
2014					13 MW
2015	PI EPU 58 MW MH 375 MH 350				13 MW
2016	PI EPU 58				13 MW
2017					13 MW
2018			195 MW		13 MW
2019			195 MW		13 MW
2020					26 MW
2021	MH 125				13 MW
2022			195 MW		13 MW
2023					13 MW
2024			195 MW		13 MW
2025		729 MW	364 MW		13 MW

In comparison with the proposed plan, the Full Wind scenario adds one fewer combustion turbine, eliminating the one proposed for 2020. The Full Wind scenario also increases

Updated Table 4.9 compares the PVRRs of the Full Wind scenario with our proposed plan.

Updated Table 4.9
PVRR Differences Between Proposed Plan and Full Wind Scenario

PVRR ($millions)	Base Case	30% RES	Difference
Base Assumptions	$78,199	$79,231	$1,032
High Gas + 20%	$79,436	$80,260	$825
Low Gas -20%	$76,915	$78,167	$1,252
Low CO2 $9/ton 2012	$81,727	$82,511	$784
Mid CO2 $17/ton 2012	$84,826	$85,406	$580
High CO2 $34/ton 2012	$91,139	$91,322	$183
Late CO2 3 Source Blend	$83,121	$83,721	$601
High Load	$80,978	$82,082	$1,105
Low Load	$75,096	$76,127	$1,031

These results indicate that under our current assumptions, the Full Wind scenario is more expensive than the proposed plan under base assumptions and all sensitivities. However, the assumptions surrounding these scenarios could change in the future. The PTC could be renewed, wind and solar prices could fall, the costs of other resources and fuels could rise, and many other factors can and will affect the cost of adding renewables to our system in the future. We propose to monitor the market for wind and other renewables after 2012 and add individual wind projects that prove to be cost effective for our customers. To the extent that we believe RES compliance will result in significant rate impact, we will explore our options, including the option to request an off ramp, at that time.

The emission differences between the two scenarios are presented in Table 4.10.

Table 4.10
Emissions Comparison
Tons Emitted, 2010-2049

	Updated Plan	Full Wind	Difference
SOx	977,710	933,762	(43,949)
NOx	757,893	724,508	(33,384)
CO2	915,924,364	865,138,900	(50,785,464)
CO	276,006	247,214	(28,792)
PM10	97,758	92,099	(5,659)
HG (lbs)	7,461	7,202	(259)

Emissions are lower in the Full Wind scenario, which could be a benefit for compliance with future environmental requirements. We would need to understand the costs of alternative means of compliance before suggesting that installing additional renewables is the better option. We will continue to evaluate both cost and emissions as we move forward to implement our renewable strategy.

E. Conclusion

Our updated plan combines reasonable cost and fuel diversity, and takes into consideration current and expected environmental regulation. As we discuss in subsequent sections, it provides considerable flexibility to adjust resource additions as more clarity emerges around the economy as well as key policy decisions. Implementation of this plan over the next several years will allow us to operate our system efficiently and meet our customers' needs at an overall reasonable cost. We will continue to monitor and analyze our resource needs and provide additional detail regarding our plans in our next Resource Plan filing.

IV. NUCLEAR GENERATION

A. Introduction

Our two nuclear power plants are essential parts of our generation portfolio. Monticello and Prairie Island together provide nearly 30 percent of our customers' electricity requirements. These low-cost, base load units operate at high capacity factors, around the clock, and without emissions associated with fossil fuels. The Commission previously authorized additional spent fuel storage, which will permit these plants to operate for another 20 years. We also successfully obtained license renewals from the NRC authorizing operation for another 20 years at both plants. In addition, the Commission previously approved a 71 MW capacity expansion at Monticello in January 2009 and a 164 MW capacity expansion at Prairie Island in December 2009.

The increases in plant generating capacity at Monticello and Prairie Island are an integral part of our generation program incorporated in our initial Five-Year Action Plan. This update reports on the status of our efforts to implement generating capacity increases at Monticello and Prairie Island. Our program of initial capital projects to refurbish and increase capacity is nearing completion at Monticello. During this process, we experienced complications in the NRC's licensing process that have delayed our ability to operate at higher production levels. In addition, during the process of detailed design, procurement, and installation of equipment, we have experienced higher costs than previously anticipated.

We are incorporating lessons learned from the Monticello project, our assessment of other utilities' experiences, and the NRC's reaction to Fukushima Daiichi, into our planning at Prairie Island. Because of our experience with the Monticello capacity expansion and other costs pressures, we believe it is appropriate for the Commission to consider our refreshed analysis and reaffirm before we proceed with additional investment for our capacity expansion program at Prairie Island. Based on our current analysis, completing the expansion program appears to remain cost-effective for our customers, but a separate Change in Circumstances proceeding would allow for additional review of these issues.

B. Monticello

Industry experience demonstrated that years of reactor safety technology improvements, plant performance feedback, and improved fuel and core designs can allow reactors such as Monticello to safely generate more power than originally licensed. Based on this experience, we proposed a program to increase capacity at Monticello by approximately 71 MW, to a total plant capacity of 656 MW. This capacity uprate program was approved by the Commission in January 2009 in Docket No. E002/CN-08-185.

To obtain greater capacity, the reactor will be operated at a higher thermal power level and changes are being made to systems at the plant to increase electrical output. The changes are not a discrete set of projects undertaken solely to increase generating capacity; rather, many of the systems, structures, and components involved are also being refurbished or replaced as part of our program to ensure the plant operates safely and reliably throughout its extended life.

Our overall program at Monticello was designed to be implemented in two phases, corresponding with two scheduled refueling outages in 2009 and 2011. During the 2009 refueling outage, detailed engineering was done to support NRC license review, equipment was designed, procurement commitments were made, and installation work was performed. As we approached the 2011 outage, adjustments were made to the implementation schedule. Work was rescheduled into two plant outages in 2011 in response to indications of slowing NRC regulatory review. The work scheduled for the normal plant refueling outage in spring 2011 was completed. However, after further analysis and discussions with NRC staff, the remaining portion of the installation work has now been deferred to the normally scheduled Spring 2013 refueling outage to minimize disruptions of plant operations.

The change in schedule is the result of a more involved and lengthier license amendment process before the NRC than anticipated. In light of the earthquake and tsunami that damaged the Fukushima Daiichi plant in Japan, the Advisory Committee on Reactor Safeguards, who advise the NRC Commissioners, has recommended that the impact of the Fukushima Daiichi accident be reviewed to assess possible impacts on the regulatory process and requirements for capacity increases at nuclear plants in the United States. Discussions with the NRC staff indicate that they will take additional time to understand the impacts of Fukushima Daiichi on power uprates at nuclear power plants like Monticello that utilize Mark-I containments. We now expect the licensing process to extend into 2013, and as a result, we have moved the remaining work needed to achieve the power uprate to the regularly-scheduled Spring 2013 refueling outage.

We anticipate the increased capacity will be available in 2013. The shift of the additional 71 MW of system capacity to 2013 does not have an impact on our Resource Plan. As discussed in our updated forecasting and resource needs assessment, we have adequate resources in the next few years even if completion of the Monticello capacity upgrade is delayed to 2013.

C. Prairie Island

The Commission approved our proposed capacity uprate program for Prairie Island, as well as additional on-site dry-cask storage to support operations for additional 20 years.[8] At that time, we estimated it was possible to expand capacity at Prairie Island by 164 MW (82 MW per unit) during refueling outages in 2014 and 2015.

[8] *See* Docket Nos. E002/CN-08-509 and E002/CN-08-510.

The Certificate of Need analysis, which is based on information gathered early in the development process before detailed engineering is completed, indicated capacity increases could provide $500 million in benefits to customers, as measured by the present value of system revenue requirements ("PVRR"). Based on additional engineering work to date, as well as other cost risks, we believe a Change in Circumstances proceeding would be appropriate as it will allow us to present and incorporate new information since obtaining the Certificate of Need.

In June 2010, we received the license renewals from the NRC allowing the plant to operate up to an additional 20 years. The NRC will not review amendments to increase output at the same time that a license renewal application is pending. Once license renewals were obtained, we proceeded with the supporting work for the license amendments needed for the EPU program. This work included more detailed engineering, preparing specifications for equipment, and issuing Requests for Proposals and receiving proposals from equipment vendors and installers. Additionally, after further discussion with bidders, performance guarantees for each proposal were received from bidders. Overall, we have spent just over $60 million to get to this stage in the process; however, we estimate at least another $20 million and potentially more will be required to complete the licensing process. Part of the remaining cost to prepare applications is in response to recent NRC guidance which emphasizes a fuller and more complete final design in applications, instead of being developed in parallel with the NRC staff's review. We also anticipate that an extended review process, 18-24 months long, is possible as the NRC considers the applicability of any lessons learned from Fukushima Daiichi.

Additionally, since our initial Resource Plan filing, both the achievable capacity and cost of the EPU program at Prairie Island have changed. As a result of the engineering to date and the performance guarantees received from vendors, capacity estimates have changed in two ways:

- *License Amendment*. In April 2010, the NRC authorized operating license amendments that allow us to rely on new feedwater flow monitoring equipment which more precisely measures plant conditions. This "measurement uncertainty recapture" effort allows us to utilize plant capacity that could not previously be used absent the enhanced precision in monitoring and increased plant capacity by 18 MW. We began operating at the higher capacity level in October 2010.

- *Low Pressure Turbines*. Our estimate of the potential capacity increase has been scaled back by approximately 29 MW. To achieve that last 29 MW increment, it now appears we would have to add improvements to the plant's low pressure turbine stages and make significant changes to condensers to reduce turbine backpressure which affects performance. Currently, our estimate of the cost of these additions could approach as much as $200 million, making the last 29 MW increment not justifiable.

After these two adjustments, we estimate 117 MW of capacity increases can be captured with the remaining EPU program.

We have also updated our analysis of the cost of the EPU program. To do this, we investigated the costs associated with a number of the major components of the program. Engineers also provided estimates of the net avoidable cost in the overall life extension and EPU capital program at the plant if chose not to proceed any further with the EPU effort. Our current estimate is that the total cost of the EPU program will be approximately $250 million, $187 million of which can be avoided if we were to terminate the program.

The updated Strategist simulation model continues to predict customer benefits will result from the completion of the remaining 117 MW of the EPU program. However, the magnitude of the remaining benefit has declined. The PVRR is predicted to be $113 million lower with completion of the EPU program compared to terminating now and adding generation at the appropriate time to meet system demand. This benefit is lower than what was found during the Certificate of Need proceeding. In addition, the analysis for this update filing did not account for the risk of cost increases that might occur during the completion of the engineering to support license applications, during the NRC review process before issue a license amendment, or as the result of unanticipated scope changes during installation. Additional review of these and other potential cost risks can be explored during a Change in Circumstances proceeding.

We did conduct limited sensitivity analysis to show why reevaluation is appropriate. Under one scenario, we increased the overall cost of the EPU program estimate by 50 percent. If the total cost of the EPU program was $375 million, approximately $310 million of which could be avoided, the modeling indicates the cost to be slightly greater than simulated benefits. The PVRR of completing the program is $40 million greater than terminating now. We also tested the impact of a delay in licensing like that experienced at Monticello. A delay of one more refueling cycle[9] changes modeling results by only $5-$10 million on a PVRR basis.

[9] Normal refueling outages are currently scheduled for both Units in 2016. Thus capacity upgrades would be available in 2016 and 2017 in this scenario.

We are currently examining the likelihood of cost increases associated with each major component of the Prairie Island EPU program. This will allow us to better assess where potential costs and benefits. We are also examining the experience of other nuclear plants like Prairie Island as they implemented EPU programs. Finally, we are assessing the similarities and differences in risk between EPU programs at Monticello, a boiling water reactor, and Prairie Island, a pressurized water reactor design. The results of this process will help inform the Change in Circumstances proceeding.

For these reasons, we believe it is appropriate to reassess the benefits of the Prairie Island EPU program. Such a review would occur before we undertake two expensive parts of the program: completing the licensing process and making equipment commitments. A Change in Circumstances proceeding would allow us to refresh this analysis using more detailed information gathered since the Certificate of Need proceeding. In addition, this formalized review by the Commission and input from all our stakeholders will help parties better assess the costs associated with proceeding with the Prairie Island EPU program. This will provide the opportunity to consider and reaffirm their interest in proceeding based on this new information.

D. Conclusion

We expect our Monticello increased capacity to be available in 2013. The shift of the additional 71 MW of system capacity to 2013 does not have an impact on our Resource Plan. Before continuing with the Prairie Island EPU program, we believe it is appropriate to reassess the benefits of the program. Although our current analysis indicates proceeding with the remainder of the program to achieve 117 MW of additional capacity is beneficial to customers, there may be additional, costs. We plan to complete our assessment and provide more detailed modeling results and analysis in a separate, comprehensive Change in Circumstances filing so that the Commission can consider the potential costs before we proceed with additional investment. We anticipate such a Change in Circumstance filing can be made before the end of the first quarter 2012.

V. BLACK DOG REPOWERING PROJECT

As a part of our initial Resource Plan, we identified repowering Black Dog Units 3 and 4 as one option to meet our customers' future energy needs. Forecasts developed for the initial filing indicated our system would require additional long-term capacity between 2015 and 2018. In addition, anticipated environmental regulations suggested the use of coal at our existing Black Dog Units 3 and 4 to no longer be feasible. Under these circumstances, we determined that retiring Black Dog's existing Units 3 and 4 (253 MW) and replacing them with an approximately 700 MW natural gas-fired combined-cycle facility by 2016 was the best available option at that time.

Developing this project has included engineering and other work necessary to bring the project online by 2016, including obtaining regulatory permits. To that extent, we filed an application for a certificate of need which can be found in Docket No. E002/CN-11-184. We committed to keep the Commission and stakeholders informed of any changes in the need or timing for the Black Dog Repowering Project because of the continuing poor economy.

Since economic growth in Minnesota as well as the country as a whole remained stalled, we updated the Black Dog CON proceeding with revised forecast information in June of 2011 ("Spring 2011 Forecast"). While discussed in detail in the Forecast section of this update, the Spring 2011 Forecast indicated customer needs had softened but, overall, still supported pursuing the Black Dog Repowering Project because a 2016 capacity deficit of 320 MW was still being projected if Black Dog Units 3 and 4 were retired. The Spring 2011 forecast could have supported a delay in to 2017 or 2018; however, a 2016 schedule remained prudent as it preserved flexibility for meeting our customers' needs should the economy recover faster than anticipated. We recognized that further declines in our forecasts could impact our need for the Black Dog Repowering Project in 2016.

As described in this update, our customers' needs are not materializing in a manner as we originally believed because the economy continues to grow slowly. Under current forecasted conditions, we no longer see a capacity deficit in 2016. Rather, our current analysis suggests we will not need additional long-term capacity resources until at least 2018.

In light of the revised forecasts provided in this update, we re-ran our modeling for the Black Dog Repowering Project. Our current analysis supports adding one or more combustion turbine peaking units rather than the large combined cycle unit proposed in the Black Dog Repowering Project to fulfill our projected 2018 capacity needs. For example, a model comparing a base case, which adds generic combustion turbines in 2018, 2019 and 2020 but does not include the Black Dog Repowering Project, against scenarios where the Black Dog Repowering Project is placed in-service in 2016, 2017, 2018, and 2019 found the base case to be consistently more cost-effective.

Black Dog Scenarios: PVRR Differences

	PVRR ($millions)	Difference from Base
Base Case	$78,199	$0
Black Dog 2016	$78,216	$17
Black Dog 2017	$78,207	$9
Black Dog 2018	$78,193	-$6
Black Dog 2019	$78,215	$17

Since the Black Dog Repowering Project proved to be marginally more cost-effective in 2018, we performed additional analysis. This is typical when scenarios are this close since small changes in assumptions can change the outcome for the entire modeling period.

We analyzed PVRR savings broken down by 10-year periods for the next 40-years. Examining the PVRRs by periods allows us to identify when the savings of one option over another are occurring within the 40 year modeling period. The base case and combustion cycle assumptions remained the same. Our results are as follows:

PVRR Differences by 10-year Period

PVRR Deltas – ($millions)	**Total**	**2011-2020**	**2021-2030**	**2031-2040**	**2041-2050**
Base Case	$0	$0	$0	$0	$0
Black Dog 2016	$17	$200	-$16	-$83	-$85
Black Dog 2017	$9	$154	$8	-$74	-$79
Black Dog 2018	-$6	$104	$31	-$68	-$73
Black Dog 2019	$17	$81	$81	-$67	-$79

In general, this analysis concludes that adding combustion turbines is more cost-effective than the Black Dog Repowering Project in the first 10-20 years. In the 2018 scenario, for example, in years 2011-2030, the PVRR of the Base Case is $135 million lower than the Black Dog CC case. In years 2031-2050, the Black Dog CC case saves $141 million over the Base Case. While these two periods net out to a PVRR difference of about $6 million, all of the savings for the CC over the base case occur in the last half of the modeling period. In the early years, the Optimized Plan is a better value for our customers.

We also performed sensitivities on these scenarios. The PVRR Differences of the sensitivities are as follows:

PVRR Deltas- $millions	Base Case	BD CC 2016	BD CC 2017	BD CC 2018	BD CC 2019
Base	$0	$17	$9	($6)	$17
High Gas	$0	($16)	($23)	($36)	($10)
Low Gas	$0	$59	$48	$32	$53
Low CO2	$0	($19)	($26)	($40)	($17)
Mid CO2	$0	($53)	($59)	($72)	($48)
High CO2	$0	($161)	($158)	($164)	($133)
Late CO2	$0	($59)	($68)	($82)	($60)
High Load	$0	($60)	($61)	($70)	($5)
Low Load	$0	$273	$253	$227	$197

We note the models above do not conclusively support adding combustion turbines as the Black Dog Repowering Project provides value in later years. Again, considering the PVRR savings broken down into 10-year periods, the Black Dog Repowering Project has much higher costs than the Base Case over the first 20 years.

2018 Black Dog CC Sensitivities
PVRRs by 10-year Periods

PVRR Deltas- $millions	Total	2011-2020	2021-2030	2031-2040	2041-2050
Base BDCC 2018	($6)	$104	$31	($68)	($73)
High Gas	($36)	$100	$21	($79)	($78)
Low Gas	$32	$109	$46	($57)	($67)
Low CO2	($40)	$101	$18	($79)	($81)
Mid CO2	($72)	$99	$7	($89)	($88)
High CO2	($164)	$80	($25)	($113)	($106)
Late CO2	($82)	$103	$8	($97)	($96)
High Load	($70)	$37	($12)	($44)	($51)
Low Load	$227	$186	$199	($63)	($95)

The models which ultimately support the Black Dog Repowering Project do so in out-years. We do not believe out-year modeling is as reliable because long-term assumptions are subject to greater uncertainty. The short-term and long-term price of natural gas, and future environmental regulations are exemplary.

We believe this modeling work is informative with respect to the likely timing and type of our resource need; however, current forecasts confirm that we do not need an additional resource in 2016 or 2017. To the extent we have a need beyond that horizon, our analysis indicates the addition of combustion turbines, or continued operation of Black Dog Units 3 and 4 with natural gas and supplemented with short-term capacity contracts are more cost-effective than the Black Dog Repowering Project. We appreciate, however, that this information is imperfect. Therefore, we believe it is in our customers' best interest to withdraw our application for a Certificate of Need and companion Site/Route permit for the Black Dog Repowering Project.[10] This will allow us the opportunity to obtain more information and perform additional analysis. Part of this assessment will include examining whether we can continue operating the existing Black Dog Units 3 and 4 on natural gas after coal operations cease in 2014 due to anticipated environmental regulations as well as the age of the units. It may be that continuing to operate these units on natural gas will provide us with peaking resources that will influence the timing of later resource decisions. Such an option may be a cost-effective way to bridge our needs until the next long-term capacity addition is required and could provide us with additional flexibility in the timing and configuration of future proposed resource additions.

Our work to date on the Black Dog Repowering Project has provided our customers with considerable value and has been reasonable under the circumstances. When we first began, all signs indicated a resource would be needed by 2016. Given the time needed to bring a substantial project like this to fruition, we moved forward, while always monitoring the situation to incorporate new information. These actions were prudent. Furthermore, by establishing a viable and cost-effective option to meet future capacity needs, most of the work already undertaken will be available for future use when it becomes clear future capacity is needed. Because the Commission does not make decisions regarding cost recovery in Resource Plan proceedings, we will propose appropriate ratemaking treatment for these prudent costs in a separate filing.

In the end, the Black Dog Repowering Project may prove to be the best alternative for meeting our customers' medium-to long-term needs. It is also possible that other generation alternatives will prove to be better options. Given the continued volatility in our customers' future needs, we propose to continue monitoring the situation and thoroughly address the 2016 to 2018 planning horizon in our next Resource Plan cycle.

VI. SHERCO UNIT 3

As part of this filing, the Company provides this informational update about a recent occurrence at the Sherco Generating Station. As part of our approved action plan, in recent years, we have added generating capacity and improved production efficiency at the 800 MW Sherco Generating Station Unit 3, which is jointly owned by NSP (59%) and SMMPA (41%). In September 2011 we began a scheduled maintenance

[10] *See* Docket No. E002/CN-11-184 and Docket No. E002/GS-11-307, respectively.

overhaul that included some of the work necessary to implement several of these upgrades. On November 19, 2011, Sherco Unit 3 experienced a significant failure during turbine testing while returning to service following the scheduled maintenance overhaul. The failure at Sherco Unit 3 resulted in fires in both the turbine and generator, and caused major damage to the unit, including the generator exciter and some turbine components. No physical injuries occurred as a result of the equipment failure; minor smoke inhalation injuries occurred due to the resulting fire. Units 1 and 2 at the Sherco Generating Station were unaffected and are operating normally.

An investigation into the cause of the equipment failure is under way. At this time we do not believe this incident will cause us to revise our Five Year Action Plan in the Resource Plan. However, we will reassess possible impacts to the Resource Plan after we conclude our investigation. While initial assessments indicate significant damage, repair scope and a projected return to service date for Sherco Unit 3 will not be known until the unit is disassembled and the extent of damage is fully known. We will keep the Commission and stakeholders informed as we investigate the cause and implications of this incident. We plan to open a new docket for future reports so that any updates related to this incident can be reviewed in a separate proceeding.

VII. ENVIRONMENTAL REGULATORY LANDSCAPE

A. Introduction

The Environmental Protection Agency ("EPA") has issued or is expected to issue several environmental regulations that impact our system within the Five-Year Action Plan period. In our initial Resource Plan filing, we provided an analysis of several pertinent EPA regulations and explained how they interact with our resource planning efforts. This update builds upon our original analysis, discussing how recent developments influence the Five-Year Action Plan. From an environmental perspective, our Five-Year Action Plan is characterized by:

- *Black Dog Units 3 and 4 Natural Gas Conversion.* Due to compliance costs and the units' age, we have concluded it is in our customers' best interest to discontinue using coal at Black Dog Units 3 and 4, shifting these units to natural gas in 2014. We also anticipated retiring these units completely once the Black Dog Repowering Project was placed in service. We now are investigating how long we may be able to continue to operate Units 3 and 4 on natural gas as an option to ensure adequate capacity on our system until the next generating addition is added.

- *Continued Evaluation of Sherco 1&2.* We continue to evaluate potential options for these units as they approach the end of their initial depreciation schedule in 2023. The EPA's pending review of the Minnesota Pollution Control Agency's ("MPCA") determination of the appropriate Regional Haze emission controls for these units might substantially impact this analysis.

- *Protecting Early Action Benefits of MERP.* By voluntarily and proactively addressing emissions at some of our oldest facilities as part of the Metropolitan Emissions Reduction Project ("MERP"), our system is well positioned to address pending and future EPA regulations, provided these early actions are given their full credit. We have challenged EPA's failure to recognize the benefits of MERP in their implementation of the Cross-State Air Pollution Rule ("CSAPR"). Regardless, our diverse resource mix allows us to comply with CSAPR requirements as currently proposed without major investments faced elsewhere in the country.

The remainder of this section explains how the following EPA regulations may impact the Company's system over the Five-Year Action Plan period:

- the proposed Mercury and Air Toxics Standards for Power Plants (otherwise known as the "Utility MACT" or "EGU MACT" rule);
- the CSAPR;
- the Regional Haze State Implementation Plan that MPCA has submitted to EPA for approval; and
- the proposed Clean Water Act, Section 316(b) Rule regarding Fish Protection at Cooling Water Intakes for Existing Steam Electric Plants.

B. Mercury and Air Toxics Standards

On March 16, 2011, the EPA proposed Mercury and Air Toxics Standards for power plants, which would replace the court-vacated Clean Air Mercury Rule. The proposed rule would require installation of Maximum Achievable Control Technology ("MACT"), as well as implementation of other emissions reduction strategies, to limit emissions of mercury, acid gases, and other hazardous air pollutants from power plants. We expect the proposed rule to be finalized in December of 2011 and compliance required within three years of final adoption. The discussion below is based on our assessment of the likely impact of the proposed rule, as it is not yet final. Our analysis could change, however, should the EPA modify the proposed rule in response to public comment.

According to our analysis, five units at three of our electric generating facilities would be impacted by the Utility MACT rule. These facilities are:

- Black Dog Units 3 and 4;
- Sherco Units 1 and 2; and
- Bay Front Unit 5.

The Utility MACT rule, as drafted, would apply to two other units on our system, unit 1 at the Allen S. King Generating Plant and unit 3 at Sherco, but it does not appear that additional controls are required for compliance at either unit.[11]

In addition, a related EPA rule – known as the Industrial Boiler ("IB") MACT – may impact two other units at our Bay Front Generating Plant. The IB MACT has been stayed, pending EPA's upcoming reconsideration of multiple aspects of the final rule. The discussion below is based on our assessment of the likely impact of the IB MACT rule as currently written, but our analysis could change depending on EPA's final determination as to the rule requirements.

1. *Black Dog Units 3 and 4*

Constructed in 1955 and 1960, respectively, Black Dog Units 3 and 4 are both coal fired units. We evaluated the costs of retrofitting these units to comply with the Utility MACT rule and other pending EPA regulations such as CSAPR. Based on our analysis, including an assessment of the compliance costs and the units' age, we concluded it would not be in our customers' best interests to continue operating these units using coal. Instead, we developed plans to switch these two units to natural gas-only operations prior to the EGU MACT compliance deadline, which we currently anticipate to be on or about January 1, 2015. We expect to ultimately retire these units and replace them with new natural gas generation but, as described in this update, decisions about the size and timing of that replacement generation are still pending.

[11] King Unit I was constructed in 1968 and recently rehabilitated as part of MERP in 2007. King Unit 1 is a coal-fired unit that is subject to the Utility MACT rule and other pending EPA regulations. MERP has well positioned King Unit 1 for complying with these regulations and no further action is anticipated at this time. Sherco Unit 3 was constructed in 1988 and is a coal-fired unit that is subject to the Utility MACT rule and other pending EPA regulations. Sherco Unit 3 is equipped with control technologies that leave it well equipped for complying with these regulations and no further action is anticipated at this time. In addition, both King Unit 1 and Sherco 3 have installed control technology for mercury as required by the Minnesota mercury emission reduction statute.

2. *Sherco Units 1 and 2*

Units 1 and 2, totaling a summer-rated capacity of 1,379 MW of coal-fired generation, are located in Becker, Minnesota, and were constructed in mid-1970. We believe Utility MACT compliance will require two projects at these units:

- *Activated Carbon Injection Project*: To control mercury emissions, we expect to add activated carbon injection at these two units. We estimate this project will cost $12 million over a three-year period (2012–2014). This project is also part of our Minnesota Mercury Emissions Reduction Act of 2006 compliance program.[12]

- *Wet Electrostatic Precipitator Project*: We expect that we will need to replace and upgrade components of the wet electrostatic precipitators on these units to further reduce fine particulate emissions. We estimate this project would cost $10.5 million over a five-year period (2012–2016).

3. *Bay Front Units 1, 2 and 5*

These three units, totaling 76 MW of generation capacity, are located at our Bay Front Generating Facility in Ashland, Wisconsin, and were constructed between 1948 and 1956. These units used a combination of coal, waste wood, railroad ties, tire-derived fuel, natural gas, and petroleum coke as a fuel source. The proposed Utility MACT rule applies only to Unit 5 and, as with Black Dog Units 3 and 4, we conclude it would be cost prohibitive to perform the upgrades necessary to allow for continued operation on coal. We plan to comply with the proposed Utility MACT rule by switching Unit 5 from coal to natural gas-only firing on or about January 1, 2015. We also anticipate needing to install fabric filter baghouses on Units 1 and 2 (approximately $13 million in 2013–2014) to comply with the IB MACT and the Wisconsin State Mercury rule. Depending on baghouse effectiveness in removing mercury (determined by post-project testing), it may also be necessary to add an activated carbon injection system to Units 1 and 2 (approximately $1 million) in 2014 or 2015.

C. The Cross-State Air Pollution Rule

On August 8, 2011, the EPA finalized the CSAPR which is designed to facilitate compliance with Ozone and Particulate Matter 2.5 National Ambient Air Quality

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[12] The Company's plan was approved by the Commission on November 4, 2010 (Docket No. E002/M-09-1456).

Standards in areas of the Eastern U.S. that the EPA found to be impacted by interstate transport of emissions from upwind states. The rule requires reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") emissions from power plants in 28 Midwestern and Eastern states, including Minnesota and Wisconsin. CSAPR compliance obligations begin January 1, 2012. Minnesota is subject to annual NOx and SO_2 emissions limits, while Wisconsin is subject to both annual NOx and SO_2 limitations and to summer ozone season NOx limitations.

The CSAPR rule creates a "budget" of allowed emissions for each state. The allowance budget is then allocated to individual power plant units based on a formula utilizing the unit's historical heat input and emissions. Although emission allowances are allocated on a unit basis, utilities can aggregate their allowances to comply on a system basis. A utility can therefore comply with CSAPR by reducing emissions, purchasing allowances in markets that the EPA has established for that purpose, or through a combination of both.

Based on the initial CSAPR allocations, we may have small shortfalls in SO_2 and NOx emission allowances for 2012 and 2013 depending on demand conditions in those years. To make up for these shortfalls and thus comply with the rule, we would either have to reduce emissions or purchase additional emission allowances. Our review of EPA's CSAPR allocation methodology, however, revealed that it failed to provide sufficient credit for the early actions we took as part of the MERP to repower our High Bridge and Riverside generation facilities from coal to natural gas. These repowering projects reduced those facilities' NOx and SO_2 emissions by more than 95%, but EPA failed to credit us for our actions, contrary to its stated goals.

In order to ensure that our customers receive the full value of those early actions – actions for which they are already paying – and to guard against additional future CSAPR compliance costs, we have petitioned the EPA to reconsider its allocation methodology. We also sued the EPA in the United States Court of Appeals for the District of Columbia over its allocation methodology. We have taken these actions both to fix the current methodology of the CSAPR rule, and to guard against this CSAPR methodology establishing a precedent against early action credit in future EPA regulatory decisions.

Regardless of the outcome of our challenges to the EPA's actions, we may need to rely on some combination of operational changes and allowance purchases to comply with CSAPR. At this time, we do not anticipate that major new capital projects are necessary to comply. We continue, however, to evaluate opportunities for prudent and cost effective projects that would offer greater operating flexibility while preserving compliance margins.

D. Regional Haze

The EPA established the Regional Haze Rule in 1999. The rule is designed to improve visibility in 156 national parks and wilderness areas, collectively called "Class I" areas. Under the rule, states are required to develop and implement air quality protection plans to reduce emissions that cause or contribute to visibility impairment. States are required to regulate certain existing emission sources known as Best Available Retrofit Technology ("BART")-eligible sources. BART-eligible sources are large sources, including power plants, placed in service between 1962 and 1977 that have potential emissions greater than 250 tons per year. Sherco Units 1 and 2 are classified as "BART-eligible units," and MPCA required Xcel Energy to submit a BART analysis in 2006.

After years of analysis and review, the MPCA determined in 2009 that BART for units 1 & 2 were:

- *NOx*: Installation of low NOx burners, overfire air and other combustion controls, and
- *SO_2*: Installation of Sparger tubes as a retrofit to the existing wet scrubbers to improve SO_2 removal efficiency.

The Company has installed the required NOx controls at both units and plans to install the Sparger tubes for additional SO_2 removal between 2012 and 2014. These projects contribute to significant improvements to visibility at impacted Class I areas at a cost of less than $30 million to our ratepayers. While required because of Regional Haze program rules, these controls also assist the Company in complying with CSAPR, because they limit NOx emissions, and with Utility MACT, because improved SO_2 control also reduces acid gas emissions.

In October 2009, the U.S. Department of Interior certified to the EPA that visibility impairments at Class I areas are reasonably attributable to emissions from Sherco Units 1 and 2. This means Sherco Units 1 and 2 might also be subject to BART requirements under a separate part of the Federal Clean Air Act known as the Reasonably Attributable Visibility Impairment rule ("RAVI"), a precursor to the Regional Haze rule. The definition of BART is the same for both parts of the visibility program.

EPA is currently reviewing the MPCA's Regional Haze State Implementation Plan, which MPCA submitted in late 2009. Specifically, EPA and MPCA have been in discussions on what constitutes BART for Sherco Units 1 and 2. In its June 2011 preliminary review of the MPCA's BART assessment, EPA Region 5 indicated that it believes BART for Units 1 and 2 should include "Selective Catalytic Reduction" ("SCRs").

EPA's position that SCRs would be cost effective is based on inaccurate and unrealistically low generic project cost assumptions. Plant-specific estimates for Sherco Units 1 and 2 demonstrate that SCRs would cost customers upwards of $250 million. The MPCA considered SCRs as part of its BART review for Units 1 and 2 and determined that SCRs would not be cost-effective. Furthermore, the MPCA also found SCRs would not deliver significantly greater visibility improvement than the technology selected under MPCA's BART determination.

If the EPA ultimately requires the installation of SCRs, those controls may need to be in place as early as the 2017-2019 timeframe, depending on the timing of the EPA's decision and any resulting regulatory process.

Finally, the EPA is considering whether to allow states to substitute compliance with CSAPR for unit-by-unit BART requirements under the Regional Haze Program. If allowed, MPCA would have the option to displace unit specific BART requirements with system CSAPR compliance. Should this occur, no additional installations may be necessary at Sherco 1 and 2 to comply with the Regional Haze Program.

We committed in the Resource Plan to conduct a comprehensive analysis of the investments necessary to operate these units into the future and to compare the costs and benefits of continued operations against a number of alternatives. We propose to report our results in the next resource plan, and will include in our analysis the potential for significant investment for SCRs in 2017-2019.

E. Clean Water Act Section 316(b) Proposed Rule

On March 28, 2011, the EPA proposed new rules for cooling water intake structures at existing facilities. The proposed rule would apply to all existing utility generating plants that withdraw greater than 2 million gallons per day. Under the rule, utilities would need to retrofit intake structures to reduce the impingement of fish on intake screens by 88% or more on an annual basis. The proposed rule would also require the MPCA to set limits, on a case-by-case basis, that minimize the amount of aquatic organisms passing through intake screens (entrainment) for each site. The EPA's proposal would require compliance as soon as possible, but no later than 8 years following promulgation of the new rules. The proposal contains an exception for nuclear plants, which are given up to 15 years to comply if an NRC safety analysis is required. The EPA is expected to issue a final rule on July 27, 2012.

The EPA proposal is expected to mandate minimal technical performance standards and identify Best Technology Available ("BTA") for compliance. The proposed rules recommended performance standards that are approximately the same as what could be reasonably achieved with conversion to closed-cycle cooling; the proposed rule, however, did not mandate closed-cycle cooling.

We have been evaluating the proposed rule and believe it could have an impact on a significant number of our facilities, if it remains substantially unchanged. Changes to Section 316(b) requirements may have the effect of establishing cooling tower requirements at Black Dog in order to continue to operate Units 3 and 4 beyond 2015. We will provide further updates when the rule becomes final and its requirements clearer.

VIII. RENEWABLE GENERATION

A. Introduction

In Chapter 5 of our initial Resource Plan, we provided a significant amount of information about the amount and type of renewable energy we have on our system, as well as an analysis of our plans for adding renewable energy over the course of the resource planning period. In this section, we update that information and our plan to move forward in light of the evolving circumstances described in the Executive Summary.

Our five state system is geographically located such that we have access to some of the best wind resources in the world and access to cost-effective, reliable Canadian hydro resources directly to our north. Our renewable energy portfolio provides multiple benefits to our customers, as an intrinsic part of our commitment to maintaining a diverse, robust, reliable, clean, and affordable energy supply portfolio.

We have been aggressive in taking advantage of recent low prices for renewable energy resources, in particular competitively-priced wind and hydro generation. In August 2010, the Commission approved our most recent set of long-term capacity and energy purchases from Manitoba Hydro, effectively extending our long-standing purchases of significant hydroelectric power into 2025. This ensures that our customers will continue to take advantage of reasonably-priced and substantially carbon free generation throughout this planning period.

Further, we have been aggressive in the wind power market and have been able to take advantage of market pressures on behalf of our customers. Our recent experience shows we are well positioned to capture competitively priced renewable resources and to take advantage of the availability of the federal PTC which is set to expire at the end of 2012.

We are well ahead of the renewable energy targets established in the jurisdictions we serve. As a result, we have substantial flexibility and can adjust the timing of renewable energy additions to our system to ensure the best possible value for our customers. If wind power prices go up significantly (as is likely if the PTC expires and is not renewed), we can afford to wait for market forces to stabilize before going forward. In light of the anticipated expiration of the PTC at the end of 2012, we intend to allow the wind generation market time to adapt to the post-PTC environment before adding additional renewable generation on our system.

B. Wind Update

In 2010 and 2011, we saw significant downward price pressure in the cost of wind projects. Wind developers significantly reduced the price of proposals, in part due to lower project development and equipment costs, but also in response to the expected expiration of the PTC. The PTC reduces the cost of wind generation and its absence will create upward price pressure. After 2012, it is unclear what the cost of wind generation may be as the market adapts to the possible post-PTC environment.

To take advantage of the opportunity to procure low-cost wind generation within a short timeframe, we have increased our wind generation portfolio in advance of the PTC expiration. Since we filed the initial Resource Plan, we have added about 330 MW of wind, for a total of about 1,600 MW of wind generation currently on our system. As discussed below, we will add at least 200 MW in 2012 with the potential for an additional up to 300 MW prior to the PTC expiration, depending upon the outcome of ongoing discussions. Deploying all of these resources prior to the PTC expiration would, if successful, provide value to customers and put us substantially ahead of all of our renewable energy targets.

- *Prairie Rose Wind Farm.* In the Resource Plan, we indicated our intention to issue an RFP for up to 250 MW of wind energy, to be in service by the end of 2012. We issued the RFP on September 15, 2010, and received a broad response with favorable pricing compared to the current market for electricity. On June 30, 2011, we requested Commission approval for a power purchase agreement with Geronimo Wind Energy for the 200 MW Prairie Rose Wind Farm in Rock and Pipestone counties in Minnesota. The contract also includes an option for the Company to purchase the development rights for another 100 MW project adjacent to the Prairie Rose site. On November 10, 2011, the

Commission approved the power purchase agreement for the Prairie Rose Wind Farm.[13]

- *Nobles*. At the end of 2010, we placed into operation our second Company-owned wind farm, the 200 MW Nobles Wind Project in Nobles County, Minnesota.

- *Merricourt*. On April 1, 2011, we notified enXco that we were terminating our arrangement with them for the 150 MW Merricourt Wind Project in McIntosh and Dickey counties in North Dakota.

- *Other Wind Opportunities*. We are exploring other opportunities to add cost-effective wind generation prior to PTC expiration at the end of 2012. We may be able to obtain up to an additional 300 MW of wind generation on our system. Because these projects have not been finalized and we have not yet obtained necessary regulatory approvals, we have not included them in our base case analysis.

- *Small Wind Projects*. Since filing the Resource Plan, we have brought seven smaller wind projects on-line, totaling about 125 MW. Those projects are:
  - Ridgewind Wind Farm, 25 MW
  - Grant Wind Farm, 20 MW
  - Winona, 1.5 MW
  - Community Wind North, 30 MW
  - Valley View, 10 MW
  - Danielson Wind Project, 19.8 MW
  - Adams Wind Project, 19.8 MW

  We now have over 350 MW of small and community-based wind projects on our system, and over 100 MW pending construction in 2012.

C. Solar Update

At the time we filed our Resource Plan, we had just over 1 MW of solar generation on our system. By the end of 2011, we may have up to 4.2 MW of solar capacity on our system. Close to 3 MW of this amount is capacity added under our Solar*Rewards program, which is an energy conservation program available to residential and commercial customers. Since the launch of this program nearly two years ago, customers' interest in installing solar on their homes and businesses has been strong

[13] *See* Docket No. E002/M-11-713.

enough to allow the program to reach its statutory spending limit for 2011, and be on track to reach it again in 2012. Over 30 percent of the capacity installed under this program is from panels manufactured in Minnesota.

D. Future Renewable Needs

With our planned wind energy additions, we will have sufficient renewable generation by the end of 2012 to utilize banked RECs for several years. With the addition of the Prairie Rose 200 MW Project and the small, community-based projects described above, we expect to have RECs sufficient to satisfy our RES requirements through approximately 2020. If the additional wind generation discussed above is added to our system prior to the end of 2012, we could have adequate RECs available to meet our requirements through around 2023.

Installed generation and banked RECs allows us flexibility to time our additions of renewable energy to take advantage of favorable market conditions. This flexibility is important under current circumstances as we anticipate the expiration of the PTC and expected upward price pressure for wind generation. As a result, we believe it is appropriate to modify our Five-Year Action Plan. Previously, we proposed to add approximately 100 MW of wind generation per year through 2020. We believe it is now appropriate to reassess our wind generation procurement efforts until after 2012 to allow the potential post-PTC market to develop. We will continue to monitor market developments and will consider advantageously-priced options if they are presented to us. We will provide the Commission updates on this strategy in our periodic renewable energy compliance reports and will review this strategy in our next resource plan filing.

The table below demonstrates our compliance with the renewable targets for the states in which NSP operates, in aggregate, for years 2012, 2016, and 2020, assuming that we add no additional wind capacity beyond the projects we currently have under contract.

Compliance with Renewable Targets, without Additional Wind

	2012	2016	2020
1. NSP Retail Sales	42,073,254	43,302,825	44,301,828
2. Banked RECs at Beginning of Year	9,491,229	15,111,531	9,328,149
3. RECs Generated During Year	7,277,389	8,085,668	7,553,139
4. RECs Generated During Year as a % of NSP Retail Sales	17.3%	18.7%	17.0%
5. RECs Needed for Compliance (all jurisdictions)	6,210,538	9,304,232	11,123,896
6. Banked RECs After Full Compliance (2+3-5)	10,558,080	13,892,968	5,757,392

As shown, by using installed generation and our banked RECs, we will be able to comply with all of the renewable targets through 2020, without any additional wind beyond our current contracted projects.

We also have the possibility of adding 150-300 MW of wind by the end of 2012. The table below shows our banked RECs after full compliance for those cases:

End-of-year REC Balances with 150 and 300 MW Additional Wind

End of year RECs	2012	2016	2020
+150	10,558,080	16,049,404	10,070,264
+300	10,558,080	18,205,840	14,383,136

In order to remain in compliance with our renewable requirements in each state, we will need to add wind at some point in the latter years of the planning period. Consistent with our proposal to add wind resources when it is cost-effective to do so, to the extent that we cannot, we will further evaluate our options, including the potential to petition the Commission for a modification or delay of our renewable energy standard pursuant to Minn. Stat. §216B.1691, subd. 2b.

E. Rate Impacts of the Minnesota Renewable Energy Standard

In the 2011 legislative session, the Minnesota Legislature enacted Minnesota Statutes, section 216B.1691, subdivision 2(e), which requires utilities subject to the RES to:

> …submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation

> of the rate impact of activities of the electric utility necessary to comply with [the Minnesota Renewable Energy Standard]. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements.

On October 25, 2011, we filed our initial report under that section, and summarized our analysis as follows:

- During the 2008/2009 time frame, energy prices were about 0.7% lower with the wind resources that were part of our system than prices would have been without them. During this same period, biomass resources were slightly more expensive but still not significantly higher than non-renewable energy.

- We project that customers will pay approximately 1.4% more for energy over the next 15 years as the result of complying with the RES. Two key assumptions drive this result: 1) the PTC expires in 2013, and 2) the currently forecasted cost of natural gas for generation remains low. If the PTC is extended through 2025, rate impact of renewable energy is reduced to 0.7%.

- While the results show renewable energy to be slightly more expensive over the planning period, the differences do not appear significant. Changes in comparative factors, such as the cost of fuel, could result in renewable energy being less expensive than non-renewable alternatives.[14]

F. Conclusion

We estimate that the cost of meeting the Minnesota renewable requirements will be slightly higher than that of a plan that does not include additional generation. The actual cost to meet our renewable obligations will depend on a number of variables at the time we make decisions on incremental renewable additions: the cost of wind generation, the cost of natural gas generation and fuel, the growth rate for energy consumption and demand on our system and the existence of any other incentives or costs. For this reason, we plan to continue to analyze our renewable additions on a project-by-project basis, and will seek approval for each project as we propose to implement it. We will use our banked RECs as needed to reduce compliance costs, and will petition the Commission for modifications of the Minnesota Renewable

[14] *See* Xcel Energy Rate Impact Report (October 25, 2011) at p. 1 in Docket No. E999/CI-11-852.

Energy Standard if we believe that new renewable additions will have a significant rate impact on our customers.

IX. DEMAND-SIDE MANAGEMENT

The Company continues to strive to achieve the 1.5% savings goal established in the Next Generation Energy Act of 2007 ("Act"). We had a successful year in 2010 – achieving over 415 GWh of electric savings, or 1.35% of sales, which exceeded our goals. We believe this level of performance was possible because of the factors discussed in the initial Resource Plan. Our strategies built momentum and drove unprecedented levels of program participation. For 2011, we expect to exceed the 1.5% savings goal through a combination of traditional Conservation Improvement Programs ("CIP") and electric utility infrastructure improvements.

We are happy with these accomplishments and are committed to continuing this success. While we expect to perform at a similar level in 2012, we foresee challenges in sustaining this performance beyond 2012. More aggressive residential and commercial lighting standards, building codes and equipment standards will be phased in. Additionally, as we reach higher and higher levels of market penetration, the available market potential, absent any significant advances in energy efficient technologies, shrinks. Further, future savings could be affected if large commercial and industrial customers' requests to be exempted from CIP are approved.

To help address some of the challenges, we have actively participated in stakeholder workgroups formed to tackle issues surrounding these concerns. While these workgroups have made significant progress in many areas, work still remains to develop defensible methodologies for counting savings from behavioral programs and codes and standards changes.

Given these challenges, we continue to believe that our proposed goal working toward the 1.5% savings goal over the next several years is an aggressive goal that will require us to innovate and further strengthen our commitment to DSM.

X. CONTINGENCY PLANNING

The modifications to our Five-Year Action Plan described in this filing are driven largely by our updated forecast of customers' future energy needs. Forecasts are by their nature estimated predictions of future events based on a specific set of assumptions; actual results will differ from the forecast depending upon whether those assumptions prove accurate. Our obligation, however, is to ensure sufficient capacity is available to serve our customers, regardless of whether actual demand is higher or lower than forecast.

We are comfortable that the proposed changes to our Five-Year Action Plan will allow us to meet our customers' future needs. However, we continue to believe having options to address unanticipated changes is important as solutions can be time-consuming such that the timing of the resource is inconsistent with the need. A workable contingency plan, consisting of one or more facilities that are ready to execute when needed, would allow us to cost-effectively meet customers' needs should unanticipated changes, such as a robust economic recovery, materialize.

We believe a contingency plan would include numerous activities to prepare for rapid resource deployment. We could identify a site, request interconnection, complete engineering, and reserve equipment. In addition, we could potentially permit a facility in advance. All of these things would allow us to move swiftly in the event of an unexpected need. However, these activities are typically not pursued prior to a decision to move forward with a project. Some activities are even restricted by existing laws pertaining to certificates of need and the Commission's bidding requirements. These practical impediments, as well as the significant expense that must be incurred to develop a long-term capacity project, create disincentives to engage in advance contingency planning of this type.

Our experience with developing generation projects and making long-term capacity purchases suggests some mechanism for allowing prudent advance expenditures as part of a contingency plan is appropriate. Because we believe such a plan would benefit customers, we plan to work with stakeholders to explore mechanisms that will facilitate development and deployment of contingency plans. Legislation recognizing the appropriateness of investments needed to develop a Commission-approved contingency plan would minimize the disincentive to engage in advanced planning and may be appropriate.

As we discuss this idea with stakeholders, we believe a contingency plan should ultimately seek to develop "shelf-ready" projects. This would allow utilities to incur and recover reasonable expenses necessary to develop a "shelf-ready" facility, to be installed in the event it is needed to address a sudden increase in load or an unexpected loss of resources. We believe such a plan would be in the best interests of our customers, allowing us to avoid potentially higher costs of replacement power if we are forced to obtain it in a constrained market. We look forward to working with interested parties to develop and obtain approval for a balanced and effective contingency plan.

XI. CONCLUSION

We appreciate this opportunity to update the Commission and interested stakeholders on changing circumstances surrounding our resource plan. Through this update, we have provided the most recent forecast data and our analysis of the impacts that forecast has on our resource plan. In light of all of the factors described in this update, significant portions of our initial Five-Year Action Plan remain appropriate and should continue to be implemented.

We ask the Commission to conclude this planning cycle by approving our revised Five-Year Action Plan. This plan is designed to maximize benefits for customers and ensure that we meet their needs in a cost-effective manner. In summary, we respectfully request that the following items be implemented as part of our revised Five-Year Action Plan:

- *Black Dog Repowering Project.* Our revised Five-Year Action Plan includes withdrawal of our application for a Certificate of Need for the Black Dog Repowering Project in Docket No. E002/CN-11-184. Our latest forecasts and analysis show that the next generating resource is no longer needed in 2016; thus we can monitor the timing and need for additional resources in our next resource planning cycle. We intend to make the filings necessary to withdraw from the certificate of need proceeding and related site and route permit proceeding, Docket No. E002/RP-11-307.

- *Prairie Island Capacity Uprate Program.* We have made considerable progress in implementing this capacity increase program based on the Commission's prior authorizations in Dockets E002/CN-08-509 and E002/CN-08-510. In light of our experience with a similar program at Monticello and other recent events including increased regulatory scrutiny from the accident at Fukushima Daiichi, we recommend additional assessment of the Prairie Island program. We intend to provide a complete analysis of these issues in a changed circumstances filing.

- *Wind Procurement.* We have purchased significant wind resources and have adequate generation and RECs for several years. As the PTC expires at the end of 2012 and is not expected to be renewed, we plan to reassess the pace of our wind power acquisition program after 2012.

- *Contingency Plan.* In light of the potential for demand to fluctuate and the long time-lines involved in developing and constructing major infrastructure, we propose to engage in a constructive dialogue with stakeholders on ways to be prepared to react to future circumstances and unexpected changes in demand.

- *DSM*. DSM continues to deliver value for our customers and we are excited to continue working with our stakeholders to achieve 1.5% DSM energy savings as part of the revised Five-Year Action Plan.

- *Manitoba Hydro*. Extending our relationship with Manitoba Hydro will allow us to continue providing customers with economical service from renewable resources.

- *Monticello EPU*. We continue to include the EPU at the Monticello as part of the revised Five Year Action Plan.

Finally, we respectfully request that the Commission conclude this planning cycle based on our revised Five-Year Action Plan and schedule the next planning cycle to begin in the Spring of 2013.

System Peak (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		Growth
20%	9,422	8,814	8,798	8,871	8,957	9,030	9,116	9,189	9,271	9,371	9,450	9,511	9,605	9,658	9,744		0.24%
50%	9,785	9,215	9,217	9,305	9,402	9,495	9,581	9,672	9,760	9,839	9,918	9,981	10,031	10,069	10,094		0.22%
80%	10,154	9,670	9,739	9,902	10,055	10,219	10,396	10,521	10,692	10,823	10,990	11,135	11,270	11,403	11,533		0.91%
Reserve Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%		
System Energy (GWh)																	
20%	44,708	44,510	44,147	44,344	44,546	44,801	44,883	45,055	45,232	45,419	45,591	45,741	45,853	46,021	46,243		0.24%
50%	45,785	45,860	45,669	45,999	46,338	46,720	46,927	47,223	47,499	47,799	48,096	48,308	48,535	48,813	49,123		0.50%
80%	46,865	47,233	47,181	47,675	48,140	48,652	48,956	49,394	49,771	50,168	50,574	50,891	51,218	51,595	51,993		0.74%
Gas Price ($/mmBtu)	$4.20	$4.39	$4.86	$5.16	$5.50	$5.95	$6.22	$6.34	$6.60	$6.85	$7.27	$7.57	$7.83	$8.06	$8.35		5.03%
Nuclear Fuel Price ($/mmBtu)	$0.91	$0.88	$0.90	$0.89	$0.98	$0.99	$1.01	$1.04	$1.05	$1.07	$1.11	$1.13	$1.17	$1.19	$1.21		2.04%
CO2 Pricing ($/ton)																	
Base	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
Mid	$0.00	$17.00	$17.40	$17.81	$18.23	$18.66	$19.10	$19.55	$20.02	$20.49	$20.97	$21.47	$21.97	$22.49	$23.02		
Low	$0.00	$9.00	$9.21	$9.43	$9.65	$9.88	$10.11	$10.35	$10.60	$10.85	$11.10	$11.36	$11.63	$11.91	$12.19		
High	$0.00	$34.00	$34.80	$35.62	$36.46	$37.33	$38.21	$39.11	$40.03	$40.98	$41.94	$42.93	$43.95	$44.98	$46.04		
Late	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$4.54	$6.05	$6.50	$15.77	$16.94	$18.19	$19.54	$20.99		
CSAPR Rules																	
SO2 Pricing ($/ton)	$0	$834	$674	$627	$467	$352	$274	$166	$63	$0	$0	$0	$0	$0	$0		
SO2 Allowances (tons)	0	24500	24500	24079	24079	23053	23053	23053	21005	21005	21005	21005	21005	21005	21005		
NOx Pricing ($/ton)	$0	$924	$874	$832	$508	$469	$396	$322	$238	$203	$196	$207	$218	$229	$240		
NOx Allowances (tons)	0	16860	16860	16846	16846	16154	16154	16154	14772	14772	14772	14772	14772	14772	14732		
Wind Expansion Plan (MW)	0	0	100	100	100	100	100	100	100	200	0	100	200	0	100		
Level Wind Expansion Plan (MW)	0	0	0	0	0	0	0	0	0	100	0	0	200	100	0		
Short Term Capacity (MW)	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75

Resource Additions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
		Slayton 1 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	MH375500 125 MW	WIND_PPA 13 MW	WIND_PPA 13 MW		WIND_PPA 13 MW
		Sherco 3 8 MW	PrRose 26 MW		P Island 2 55 MW	P Island 1 55 MW				WIND_PPA 13 MW			WIND_PPA 13 MW		
		SAF Hydr 3 MW	ND_50 6 MW		MH375500 375 MW										
		NthShaok 0 MW	Monti 1 67 MW		DIV350IN 350 MW										
		GoodhuNS 10 MW	CrownHyd 1 MW												
		Fch Isld 3 61 MW	Borders 19 MW												
		DiamondK 0 MW													
		Danielsn 3 MW													
		CommWndN 4 MW													
		BigBlue 5 MW													

Resource Retirements	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
			Key City 4 -14 MW		MH500 -500 MW	Coyote 1 -100 MW	Rapidan -3 MW	Wilmarth 1 -18 MW	WSMorrn -6 MW	MNMethan -5 MW	Fch Isld 4 -64 MW	St.Cloud -7 MW	St Paul -25 MW	Fch Isld 1 -21 MW	Stahl -1 MW
			Key City 3 -14 MW		Div150In -168 MW		Div200In -224 MW	Viking -2 MW	WindPowr -3 MW		Fch Isld 3 -61 MW		MNDakota -19 MW	Chanaram -11 MW	MNWind -1 MW
			Key City 1 -14 MW					Red Wing 1 -20 MW	Moraine -7 MW		Byllesby -2 MW			Bayfront 6 -29 MW	MH375500 -500 MW
			Granite 4 -14 MW					HERC -34 MW	KODARAHR -12 MW					Bayfront 5 -22 MW	LkBnton2 -13 MW
			Granite 3 -14 MW					Flambeau 1 -14 MW						Bayfront 4 -19 MW	Invenerg 2 -161 MW
			Granite 2 -14 MW												Invenerg 1 -161 MW
			Granite 1 -13 MW												DIV350IN -350 MW

Thermal Units

	Capital Cost ($ millions)	Firm Capacity (MW)	Heat Rate (mmBtu/MWh)
Gas CT	$124	195	9.888
Gas CC	$671	729	6.713
Coal	$1,922	500	9.357
Coal w/CCS	$2,733	500	12.359

Renewable Resource

	Capital Cost	Nameplate (MW)	Capacity Credit	Capacity Factor	FOM ($000/yr)
Wind	$1,800	100	12.9%	40%	$2,000

Wind capital cost is converted to a PPA cost of $47.39 escalating at 2.36%

Certificate of Service

I, Lindsey Didion, hereby certify that I have this day served copies of the foregoing document on the attached lists of persons.

- xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota;
- xx by email; or
- xx by electronic filing.

Docket No. E002/RP-10-825
Docket No. E002/CN-08-509

Dated this 1st day of December 2011.

/s/
____
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