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.

[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.

[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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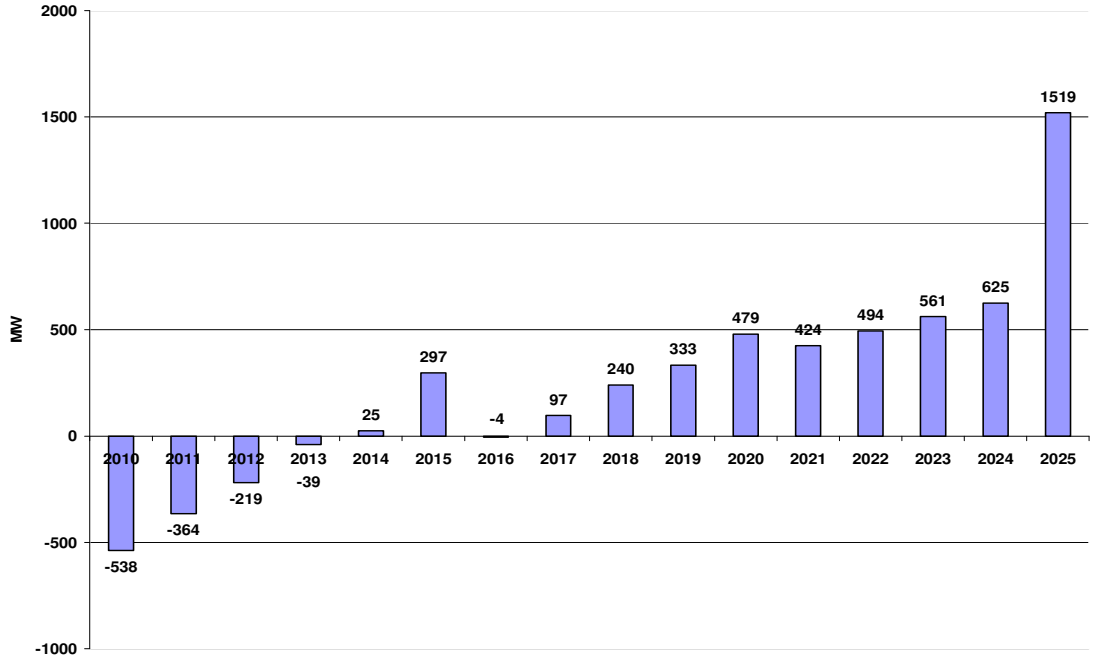
The Company has all necessary state and federal approvals to continue operating the Monticello nuclear generating plant, and has all state approvals to continued operations at Prairie Island. We are now only awaiting the final NRC approval of the Prairie Island operating license extension. Accordingly, 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

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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.