414 Nicollet Mall
Minneapolis, MN 55401

June 29, 2012

—Via Electronic Filing—

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
Capitol Building, 1st Floor
500 East Capitol Avenue
Pierre, SD 57501

RE: NORTHERN STATES POWER COMPANY
BIENNIAL TEN-YEAR PLAN

Dear Ms. Van Gerpen:

In accordance with S.D. Admin. R. Chapter 20:10:21 and S.D. Codified Laws § 49-41B-3, Northern States Power Company, doing business as Xcel Energy, hereby submits its Biennial Ten-Year Plan for Major Generation and Transmission Facilities in the State of South Dakota.

Notice of the filing has been given to each state agency and officer entitled to notice as designated in section 20:10:21:23 (see attached service list).

Please feel free to contact me at james.c.wilcox@xcelenergy.com or (605) 339-8350 if you have any questions regarding this report.

Sincerely,

JIM WILCOX
MANAGER
GOVERNMENT & REGULATORY AFFAIRS

Enclosures
c: Service List (WITHOUT ENCLOSURES)

CERTIFICATE OF SERVICE

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

BIENNIAL TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES IN THE STATE OF SOUTH DAKOTA

Dated this 29th day of June 2012

/s/
____
Lindsey Didion

South Dakota Biennial Ten-Year Plan Service List

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
Capitol Building, 1st Floor
500 East Capitol Avenue
Pierre, SD 57501

South Dakota Department of Education and Cultural Affairs
700 Governors Drive
Pierre, SD 57501

South Dakota Aeronautics Commission
Becker Hansen Building
700 East Broadway Avenue
Pierre, SD 57501

South Dakota State Engineer
Joe Foss Building
523 East Capitol Avenue
Pierre, SD 57501

South Dakota Department of Agriculture
Joe Foss Building
523 East Capitol Avenue
Pierre, SD 57501

South Dakota Department of Game, Fish, and Parks
523 East Capitol Avenue
Pierre, SD 57501

South Dakota Office of the Attorney General
500 East Capitol Avenue
Pierre, SD 57501

South Dakota State Geologist
Akeley – Lawrence Science Center, USD
414 East Clark Street
Vermillion, SD 57069

South Dakota Department of Commerce and Regulation
118 West Capitol Avenue
Pierre, SD 57501

South Dakota Office of the Governor
500 East Capitol Avenue
Pierre, SD 57501

South Dakota Governor's Office of Economic Development
711 East Wells Avenue
Pierre, SD 57501

South Dakota Department of Health
600 East Capitol Avenue
Pierre, SD 57501

South Dakota Office of Tribal Government Relations
Capitol Lake Plaza
711 East Wells Avenue
Pierre, SD 57501

South Dakota Legislative Research Council
Capitol Building, 3rd Floor
500 East Capitol Avenue
Pierre, SD 57501

South Dakota Department of School and Public Lands
500 East Capitol Avenue
Pierre, SD 57501

South Dakota Department of Labor
700 Governors Drive
Pierre, SD 57501

South Dakota Department of Environment and Natural Resources
Joe Foss Building
523 East Capitol Avenue
Pierre, SD 57501

South Dakota Department of Transportation
Becker Hansen Building
700 East Broadway Avenue
Pierre, SD 57501

Ten-Year Plan for Major Generation and Transmission Facilities

to the

South Dakota
Public Utilities Commission

Submitted by
Northern States Power Company,
a Minnesota corporation
June 2012

Northern States Power Company d/b/a Xcel Energy
2012 South Dakota Ten-Year Plan
Table of Contents

Northern States Power Company, doing business as Xcel Energy, submits the following information to the South Dakota Public Utilities Commission as required by S.D. Admin. R. § § 20:10:21:02 to 20:10:21:21 and SDCL § 49-41B-3.[1]

20:10:21:04 EXISTING ENERGY CONVERSION FACILITIES

Xcel Energy has one existing energy conversion facility in South Dakota. The table below provides the required information on this facility.

Angus C. Anson

1	Location	Minnehaha County, South Dakota	
2	Type Nameplate Capacity	Simple Cycle Combustion Turbine 119.7 MW (unit 2) 119.7 MW (unit 3) 166.3 MW (unit 4)	
3	Net Capacity Annual Production	Summer: Winter: 2010: 2011:	94 MW (unit 2) 94 MW (unit 3) 150 MW (unit 4) 109 MW (unit 2) 109 MW (unit 3) 172 MW (unit 4) 84,888 MWh (total) 53,838 MWh (total)
4	Water Source and Annual Consumption	Ground Water 2010: 2011:	 18.74 acre-ft 25.74 acre-ft[2]
5	Fuel Type Source Annual Consumption	Natural Gas Northern Natural Gas Co.[3] 2010: 1,041,075.74 MMBtu 2011: 698,505.70 MMBtu	Fuel Oil 2010: 270,813.39 gal 2011: 121,227.70 gal
6	Projected Retirement Date	Unit 2 & 3: Unit 4:	8.8 Years 24.2 Years

[1] The rules incorporate and put into effect the requirements outlined under S.D. Codified Laws § 49-41B-3

[2] We note the water consumption data was mistakenly reported as zero in prior reports. The data above represents the accurate consumption for 2010 and 2011.

[3] The natural gas fuel is purchased from independent third party suppliers and delivered through the Northern Natural Gas interstate pipeline system.

20:10:21:05 PROPOSED ENERGY CONVERSION FACILITIES

		Manitoba Hydro Purchased Power Agreement
1	Location	Manitoba, Canada
2	Why Selected	Renegotiation of Existing PPA
3	Type Nameplate Capacity	Hydro 375 MW On-Peak 350 MW Seasonal Diversity Exchange
4	Estimated Production	1,287,000 Annual MWh
5	Water Source	Nelson, Winnipeg, Saskatchewan and Laurie Rivers
6	Fuel Type	Predominately Hydro[4]
7	Disposal Plans	Not Applicable
8	Associated Facilities	Existing Transmission Path
9	Operating life with SD Fuels	Not Applicable
10	Projected End of Life	April 30, 2025[5]
11	Estimated Cost	≈ $3 Billion
12	Projected In-Service Date	2015

20:10:21:06 EXISTING TRANSMISSION FACILITIES

Listed below are our existing transmission facilities operating at 115 kV or above in South Dakota. They are all located in the eastern portion of the state. A map

[4] The contract is for system resources. Under medium water conditions approximately 98% of Manitoba Hydro generation is hydroelectric resources.
[5] April 30, 2025 is the contract end date of our PPA with Manitoba Hydro.

showing the location of our transmission lines is included as Appendix B. Currently none of these facilities are projected to be removed from service.

Type 115 kV – AC

1. Lawrence Substation in Sioux Falls to the Lincoln County Substation south of Sioux Falls - 11 miles.

2. Lincoln County Substation south of Sioux Falls to the Louise Avenue Substation (southwest side of Sioux Falls) - 5 miles.

3. Louise Avenue Substation (southwest corner of Sioux Falls) to the Cherry Creek Substation (west side of Sioux Falls) – 5 miles.

4. Cherry Creek Substation to the Grant Substation west of Sioux Falls - 24 miles.

5. Grant Substation west of Sioux Falls to Northwestern Energy (Northwestern) at Mitchell - 24 miles to Wolf Creek Interconnection owned by Xcel Energy; the remainder is owned by Northwestern.
.
6. Lawrence Substation in Sioux Falls to the Western Area Power Administration (WAPA) Substation in Sioux Falls - 1 mile.

7. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit #1) - 2.5 miles.

8. Split Rock Substation to the Pathfinder Substation approximately 4 miles northeast of Sioux Falls - 0.8 miles.

9. Pathfinder Substation to the Pipestone Substation in Pipestone, Minnesota. Approximately 34.5 miles of this line are in the state of South Dakota - 43 miles total.

10. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit #2). Approximately 1 mile of this line is double-circuited with the Split Rock-Magnolia 161 kV line; 2.2 miles total.

11. Split Rock Substation to the West Sioux Falls Substation - 17.3 miles.

12. West Sioux Falls Substation to the Cherry Creek Substation - 3.5 miles.

13. Split Rock Substation to Cherry Creek - 21 miles.

14. Split Rock to Angus C. Anson generating plant - 0.28 miles.

15. Split Rock to Angus C. Anson generating plant # 2 - 0.43 miles.

16. Brookings County to Yankee #1 - 3.7 miles of this line are in South Dakota; 13 miles total.

17. Brookings County to Yankee #2 – 6.5 miles of this line are in South Dakota; 13 miles total.

Type 161 kV – AC

1. Split Rock Substation approximately 5 miles northeast of Sioux Falls to ITC Midwest, LLC ("ITC Midwest") interconnection near Luverne, Minnesota.[6] Approximately 1 mile of this line is double-circuited with the second Lawrence-Split Rock 115 kV line. Approximately 11 miles of this line are in the state of South Dakota - 20 miles total.

Type 230 kV – AC

1. Split Rock Substation to the WAPA Sioux Falls Substation - 1 mile.

Type 345 kV – AC

1. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line to Watertown. This is a 5.1 mile line with 2.5 miles double circuit but one circuit is not energized.

2. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line to Sioux City. This is a double-circuit line - 5.1 miles with the Split Rock-Nobles line.

3. Split Rock-Nobles County-Lakefield Junction. 345 kV line Approximately 10 miles of this line are in the state of South Dakota - 90.8 miles total. 5.1 miles are double circuit with the Split Rock-Sioux City line.

---

[6] In early 2008, ITC Midwest purchased all of the high voltage electric transmission facilities of Interstate Power and Light Company (Alliant Energy) in Iowa, Minnesota and Illinois.

4. Brookings County-White 345 kV line #1. This is a 0.4 mile line.

5. Brookings County-White 345 kV line #2. This is a 0.4 mile line.

20:10:21:07 PROPOSED TRANSMISSION FACILITIES

A. Wind Generation Outlet

In order to support wind development in the Buffalo Ridge area in the Southwestern portion of Minnesota and improve service reliability to the city of Marshall, Minnesota, we proposed the BRIGO (Buffalo Ridge Incremental Generation Outlet) Project in 2006. We have completed the electric transmission development associated with the Certificate of Need (Minnesota Commission Docket No. E002/CN-06-154). These lines are:

- A second 345 kV line from the WAPA White substation near Brookings to the new Xcel Energy Brookings County 345-115 kV substation. This line is 0.4 miles long and located in South Dakota.
- A second 115 kV line from near Brookings, South Dakota (the new Xcel Energy Brookings County 345-115 kV substation is located 0.4 miles from the WAPA White Substation) east to the Yankee substation located in Minnesota. 6.5 miles of the 13-mile line is in South Dakota. Our application for a Facility Permit to construct the 115 kV line was in Docket No. EL08-001.

We have no plans to retire these facilities within the next ten years.

B. CapX2020 Proposals

A group of investor-owned, cooperative and municipal utilities in Minnesota, eastern North Dakota, eastern South Dakota, and western Wisconsin ("CapX2020 Utilities"), completed a high-level visionary study looking at the bulk transmission needs in their combined market areas over the next 15 years. This analysis, known as the CapX2020 Vision Study, identified the possible need for 345 kV lines from western South Dakota to the Twin Cities.

From this Vision Study the CapX2020 Utilities developed more specific proposals for the first group of new high voltage lines needed, referred to as Group 1 projects. The Group 1 projects include three 345 kV projects, and one 230 kV project. The approximate lengths and general location of the proposed 345 kV and 230 kV lines are as follows:

- A 230 mile, 345 kilovolt line between Brookings, South Dakota, and the southeast Twin Cities, plus a related 30 mile, 345 kilovolt line between Marshall, Minnesota, and Granite Falls, Minnesota ("Brookings Project") at a total estimated cost between $650 and $800 million;
- A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota ("Fargo Project") with a total estimated cost between $500 and $750 million;
- A 150 mile, 345 kilovolt line between the southeast Twin Cities, Rochester, Minnesota, and La Crosse, Wisconsin ("La Crosse Project") with a total estimated cost between $400 and $500 million; and
- A 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota ("Bemidji Project") with a total estimated cost between $100 and $140 million.

The first segment of the Fargo Project was placed in service in 2011 and the remainder of the project is currently under construction. The Bemidji Project is also currently under construction and completion is expected by the end of 2012. The Brookings and La Crosse Projects are not yet under construction, and will be placed into service over the next few years with total project(s) completion in 2015.

Xcel Energy and Great River Energy, on behalf of the other participating CapX2020 Utilities, filed a CON application for the three 345 kV projects (Brookings, Fargo and La Crosse Projects) with the Minnesota Public Utilities Commission on August 16, 2007. The Minnesota Commission approved CONs for all three 345 kV projects.

A portion of the Brookings project is proposed to be constructed in South Dakota. The Company and Great River Energy, on behalf of the other owners of the Brookings Project filed a Route Permit application with the Minnesota Commission on December 29, 2008 (Docket No. ET-2/TL-08-1474). The Minnesota Commission issued the final Route Permit for the Minnesota portion of this Project in May 2011 and the South Dakota Commission granted the Facility Permit for the South Dakota portion of the Brookings Project in June 2011. This project was also approved by MISO and designated as a Multi Value Project ("MVP") in December 2011.

With regard to the Fargo Project, in April 2009, a Route Permit for the Monticello to St. Cloud segment of the Monticello-Fargo project was filed in Minnesota. In October 2009, a Route Permit for the St. Cloud to Fargo segment of the Monticello-Fargo project was filed in Minnesota. The route permit was approved in June 2011.

With regard to the Bemidji Project, in March 2008, Otter Tail and Minnkota Power Cooperative filed a CON the project with the Minnesota Commission. A route application for this project was filed June 2008. In July 2009, the Minnesota Commission unanimously approved the Bemidji project CON. The Minnesota Commission gave route approval in 2010.

With regard to the La Crosse, Project, a Route Application was filed with the Minnesota Commission in January 2010. A Route Permit was filed later in 2010 in Wisconsin for the La Crosse project and approved in early 2012. None of these projects have a current retirement date estimated and are presumed to have an approximate 40 year life.

The CapX2020 projects will benefit South Dakota by improving transmission infrastructure and reliability, alleviating the existing constraints on deliveries, and expand transmission capability to allow expanded generation investment, especially wind generation.

More information about the CapX2020 initiative is available at www.capx2020.com.

C. MISO MVP Portfolio

- A 70 mile, 345 kilovolt line between Brookings County, South Dakota and Big Stone City, South Dakota at a total estimate cost of approximately $230 million.

The MISO MVP Portfolio is a collection of 17 individual projects and associated underbuild approved by the MISO Board of Directors in December 2011. The portfolio was designed to facilitate the delivery of the required renewable energy to meet renewable portfolio standards and goals across the MISO system as well as increase system reliability, transfer capability and decrease market congestion. The portfolio cost is approximately $5.2 billion (2011 dollars) which equate to benefit to cost ratios of 1.8 - 5.8 depending on the future assumptions. The portfolio was constructed over several years linking together several planning efforts including past MTEP studies and the Regional Generator Outlet Study (RGOS). Xcel Energy and Otter Tail Power Company are joint partners in the Big Stone South to Brookings County 345 kV project with Xcel Energy the development manager. A facility Permit was granted to Otter Tail Power in January 2007 for approximately 40 miles west of Big Stone City to just north of Gary, SD. Xcel Energy plans to file a Facility Permit with the Public Utilities Commission in early 2013 for an additional 30 miles from just north of Gary to the existing Brookings County Substation. Xcel Energy held public meetings in the project area in June 2012 and has been meeting with local government officials, state legislators and co-ops. The project in-service date is 2017.

20:10:21:08 COORDINATION OF PLANS

Xcel Energy is a member of the Midwest Reliability Organization ("MRO"). The purpose of which is to ensure the reliability and security of the bulk power system covering the states of Wisconsin, Iowa, Minnesota, Nebraska, and most of South Dakota as well as the Canadian provinces of Saskatchewan and Manitoba. As such, the members of the non-profit organization meet to discuss reliability and security issues. There are numerous committees that develop standards, guidelines, and reporting procedures for everything from load shedding to vegetation management. More information about the organization can be found at http://www.midwestreliability.org.

The Company is also a participant in the MN-TACT (Minnesota Transmission Assessment & Compliance Team) along with several other utilities covering Minnesota, Western Wisconsin and parts of North and South Dakota. The purpose of this analysis is to develop an understanding of the transmission system topology, behavior and operation. This analysis is performed to meet NERC Transmission Planning Standards TPL-001 thru TPL-004.

All major transmission planning performed by the Company is now coordinated through the Midwest Independent Transmission System Operator, Inc. on a regional basis, consistent with the Federal Energy Regulatory Commission orders (a) dated May 19, 2000 (FERC Docket No. EC00-60-000) authorizing the transfer of functional control of our high voltage transmission system to the Midwest ISO; (b) dated December 20, 2001[7] finding the Midwest ISO to be the first FERC-approved regional transmission organization ("RTO"); and dated February 15, 2007 (Order No. 890), requiring RTOs and their member utilities to use coordinated regional planning.[8] The

---

[7] FERC Docket Nos. RT01-87-000, RT01-001, ER02-106-000 and ER02-108-000.

[8] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) (Order No. 890), *order on reh'g*, 73 Fed. Reg. 2984 (Jan. 16, 2008),

Midwest ISO issues an annual Midwest ISO Transmission Expansion Plan ("MTEP") after coordinated planning and stakeholder review. Prior to 2007, these plans were issued biennially. The current MTEP 2009 series of projects was approved by the Midwest ISO Board of Directors in December 4, 2009 and is available at the Midwest ISO web site at www.midwestiso.org.

As a result of complying with the FERC Order No. 890 rules, the Midwest ISO has implemented its own Sub-Regional Planning Meetings. We participate in the Western Region meetings. This group provides a forum for stakeholder input and coordination of plans and we actively participate in this. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities.

Another example of this coordination by the utilities is the formalization of the Minnesota Transmission Owners ("MTO") organization. The MTO consists of all transmission owning utilities in Minnesota. The MTO was formed to submit coordinated biennial transmission planning reports to the Minnesota Commission as required by Minn. Stat. 216B.2425. Some MTO utilities also serve eastern North Dakota and eastern South Dakota. The MTO group is presently developing coordinated short-term regional plans and longer term vision plans for the bulk transmission needs throughout the upper Midwest and the transmission required to meet the various states' Renewable Energy Standards. The MTO group also performs an annual 10-year assessment of the members' utility systems for compliance with the North American Electric Reliability Corporation Transmission Planning ("TPL") standards. The MTO utilities also coordinate their planning with the CapX2020 planning processes and the Midwest ISO MTEP processes.

We also participate in Interconnection-wide transmission planning, currently being facilitated under the Eastern Interconnection Planning Collaborative (EIPC) effort, funded by the Department of Energy. The EIPC effort is focused on a high level look at the transmission needs east of the Rocky Mountains (excluding parts of Texas).

In addition, the Company prepares its own resource plan and submitted a copy of that plan to the Commission consistent with the Settlement Stipulation and Commission Order in Docket No. EL09-009. We include an update to that previously-filed resource plan as Appendix A.

FERC Stats. & Regs. ¶ 31,261 (2008) (Order No. 890-A); *order on reh'g* 123 FERC ¶ 61,299 (Order No. 890B) (June 23, 2008). The Midwest ISO's Order No. 890 regional transmission planning process was conditionally accepted for filing in *Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶ 61,164 (May 15, 2008).

20:10:21:09 SINGLE REGIONAL PLANS

As described in the previous section the Company continues to work with the Midwest ISO and other coordinated regional utility groups to evaluate potential transmission needs in the future and to develop coordinated regional plans as required to meet those needs.

20:10:21:10 SUBMISSION OF REGIONAL PLANS

Regional Plans, by virtue of their geographic coverage, involve a collaborative effort of multiple utilities. As the CapX 2020 effort has shown, we and the other utilities in this region are actively analyzing and developing coordinated regional plans. This analysis includes the active participation of the MTO and the Midwest ISO planning efforts. This effort is part of the Midwest ISO MTEP regional planning process. As specific plans for additional facilities are developed, they will be submitted with subsequent 10-year plans.

The Midwest ISO MTEP is subject to review and approval by the Midwest ISO's independent board of directors. Proposals to construct specific MTEP approved facilities in South Dakota would be submitted to for Commission approval as required.

SMARTransmission Study

We are also participating in the Strategic Midwest Area Renewable Transmission (SMART) Study that was commissioned in August of 2009 by a consortium of regional transmission owners. The SMART study's goal is to develop a 20-year transmission plan that ensures reliable electricity transport, provides an efficient transmission system to integrate new generators and foster efficient markets, minimizes environmental impacts, and supports state and national energy policies. Phase One of the study identified future transmission needs in the Upper Midwest to support renewable energy development and to transport that energy to population and electricity load centers. Study participants evaluated various transmission alternatives designed to support the integration of significant new wind generation within the study area, including North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and Ohio. The plans would accommodate the integration of up to 57 Gigawatts of wind generation. The study's Phase One results recommend three alternatives for further study based on a rigorous reliability assessment and stakeholder input. One of the alternative is the use of 765-kilovolt extra-high voltage transmission lines, another includes 765-kilovolt combined with limited use of high-voltage direct current transmission lines, while the third constitutes a combination of both 345-kilovolt and 765-kilovolt transmission lines. The three alternatives will be evaluated further during the second phase of the study.

The Phase One report can be downloaded at www.smartstudy.biz. We are co-sponsoring the study with Electric Transmission America – a joint venture of American Electric Power, MidAmerican Energy Holdings Company, American Transmission Company, Exelon Corp., and NorthWestern Energy.

Regional Generator Outlet Study (RGOS)
In an effort to align the transmission development efforts associated with renewable energy mandates in the upper Midwest, MISO has begun a study to develop a streamlined transmission plan to enable utilities to meet the various renewable energy mandates in the MISO footprint. The study was divided into two phases. The first phase focused on the upper Midwest, including Minnesota, North Dakota, South Dakota, Iowa, and Wisconsin, the area of most intense wind development interest in the MISO footprint. Upon completion of the first phase, the remainder of the MISO footprint was brought into the effort.

The study began by identifying appropriate zones for new wind in each state being studied. The state commissions in the Upper Midwest Transmission Development Initiative (UMTDI) played a critical role in developing and gaining regulatory buy-in for the wind zone assumptions being used. After settling on wind zone assumptions and developing estimates of the amount of wind necessary to meet state mandates, MISO and stakeholders developed a number of potential transmission plans to deliver that energy to load and then tested and refined those solutions. When the remainder of the MISO footprint was brought into the study scope, the plans were further refined to eliminate lightly-loaded or redundant facilities. MISO published the findings of the RGOS effort in late summer 2010. This study may be found at: https://www.midwestiso.org/Planning/Pages/RegionalGenerationOutletStudy.aspx

20:10:21:11 UTILITY RELATIONSHIPS

Northern States Power Company-Minnesota is an operating company subsidiary of Xcel Energy Inc., a public utility holding company, and we are affiliated with three other regulated public utilities: Northern States Power Company-Wisconsin, Public Service Company of Colorado, and Southwestern Public Service Company. NSPM is a member of the Midwest ISO, the first FERC-approved regional transmission organization, or RTO. As an RTO, the Midwest ISO provides regional tariff administration services and operates a Day-ahead and Real-time regional wholesale energy market pursuant to its Open Access Transmission and Energy Markets Tariff ("TEMT"). The Midwest ISO implemented a regional planning reserve market 2009, pursuant to Module E of the TEMT[9]. The Midwest ISO is also the Regional Reliability Coordinator for the NSP System.

We are also a member of the MRO which is the Regional Entity responsible for enforcement of mandatory electric reliability standards adopted by the North American Electric Reliability Corporation.

We also contract with WAPA for certain transmission services needed to serve our retail loads in South Dakota.

20:10:21:12 EFFORTS TO MINIMIZE ADVERSE EFFECTS

The Company uses a multi-step effort to minimize adverse effects resulting from siting, constructing, operating and maintaining large electric generating plants and high voltage transmission lines. These efforts relate to long-range planning and coordination, environmental site and route analysis, and to ensure the effects of construction and operation practices are minimized.

High voltage transmission facility plans are coordinated with the Midwest ISO, other area power suppliers and load serving entities in order to develop, whenever possible, joint use facilities. Coordination with others can reduce the number of facilities by providing for joint ownership and operation of facilities.

Once the need for generation or transmission is identified, an initial site or route search is begun by defining a broad study area to locate the facility. A broad range of information about the physical, biological and cultural environment within the study area is then collected. As information on such factors as land use, air and water quality, plants and animals, transportation and social services, and local and regional employment becomes available, various siting criteria are used to define preferred and alternate routes and sites. We prefer to develop a project with the cooperative assistance of state and local agency officials, neighboring transmission utilities (such as Northwestern, WAPA, Missouri River Energy Services and ITC Midwest), and affected landowners in order to assure the widest possible considerations of information, concerns and options. It is our policy to ensure compliance with all

[9] Effective September 9, 2009, the Midwest ISO began to provide a regional ancillary services market ("ASM").

local, state and federal regulatory requirements in the development and location of proposed projects.

Because of the detail involved in a major generation or transmission project, we continue to refine site and route engineering once permits have been granted. This allows us to adjust for new developments that may arise during construction, such as the need for changes in locations, land use or construction techniques, and allows any concerns to be addressed and mitigated without undue delay and expense. We are committed to working with affected landowners to mitigate environmental and land use problems which may arise as a result of construction and maintenance activities.

20:10:21:13 LOAD MANAGEMENT EFFORTS

The Company's load management efforts in South Dakota reduce peak demands, especially during the summer months, which can help delay or avoid more expensive electric generation and purchased power needs.

On January 1, 2012 we launched a demand side management program in South Dakota, approved in South Dakota Commission Order EL11-013. The DSM portfolio includes load management, conservation, and consumer education programs aimed at both residential and commercial customers.

Commercial programs in the DSM portfolio include:

- Lighting Efficiency (conservation)
- Business Saver's Switch (load management)
- Peak and Energy Control (load management)

Residential programs in the DSM portfolio include:

- Ground Source Heat Pumps (conservation)
- Residential Home Lighting (conservation)
- Residential Saver's Switch (load management)
- Consumer Education

Combined these programs aim to reduce peak demand by about 3MW and conserve 3.6 GWh per year. The overall budget for these programs is not to exceed $775,041 per year.

20:10:21:14 LIST OF REPORTS RELATED TO PROPOSED FACILITIES

MTEP09 Report: December 2009

RGOS Phases I & II: November 2010

Minnesota Transmission Assessment and Compliance Team 2010 Transmission Assessment: April 2010

MTEP10 Report: November, 2010

Minnesota Transmission Assessment and Compliance Team 2011 Transmission Assessment: July 2011

MTEP11 Report: November 2011

RGOS Phase III: November 2011

Multi-Value Project Portfolio: December 2010

Xcel Energy 10-Year Plan Load-Serving Study: December 2011

20:10:21:15 CHANGES IN STATUS OF FACILITIES

1) **Sherco Unit 3 Upgrade:** This project involves replacing the generation step up transformer and steam turbine and will result in an increase of about 20 MW of which our share will be approximately 12 MW because of our joint ownership of this unit with the Southern Minnesota Municipal Power Agency. During the final post-overhaul testing in November 2011, the unit experienced significant vibration damage. Based on our current assessment of conditions, our restoration plan targets Sherco 3 coming back online in the first quarter of 2013. However, the restoration is complex and given the remaining work to be done, some degree of uncertainty remains.

2) **Bay Front Boiler #5 Gasification Project:** The Bay Front Plant is located in Northern Wisconsin and is owned by NSPW. Two of the units at the plant have already been reconfigured to run on biomass. A third unit, Boiler #5 is currently fueled by coal and petroleum coke, but due to this boiler's age, the location of the Bay Front facility, and pending changes to environmental permit compliance requirements, we are finding that it will not be cost-effective to continue to operate

this boiler on those fuels. As a result, we are exploring various options to reconfigure this unit to run on biomass.

3) **Monticello:** Federal regulators in November 2006 approved a 20-year license extension for the Monticello nuclear plant. To accommodate operations to 2030, we also sought and gained approval from Minnesota regulators for expanded on-site storage of used nuclear fuel at Monticello. The dry storage facility was built in 2008, and it currently houses 10 containers of used fuel. The Minnesota Commission has approved our request to expand generating capacity at the Monticello Nuclear Plant by approximately 71 MW. Federal action on that request is pending.

4) **Prairie Island:** Our application to renew the operating licenses of the two reactors at Prairie Island was approved by the Nuclear Regulatory Commission in June 2011. The Minnesota Public Utilities Commission ("MPUC") approved our request for up to 35 additional dry casks to store used nuclear fuel. The additional casks are needed to accommodate operations during a 20-year license extension period. The MPUC also approved our request to expand the generating capacity of each of the two units at Prairie Island. On March 30, 2012, we submitted a Change of Circumstance filing to the MPUC addressing our proposed reduction in size and a delay in the federal review process and requesting that the MPUC find that the revised project remains in the public interest. The filing currently awaits a decision by the MPUC.

5) **Black Dog Repowering:** We have been studying repowering the remaining coal facilities (units 3 and 4, together about 270 MW) at the Black Dog facility. Black Dog units 3 and 4 were installed in 1955 and 1960 respectively and are currently near the end of their economic and engineering life. Changes to environmental permit compliance requirements will likely result in these units ceasing coal-fired generation in 2015.

6) **Louise Avenue Substation:** In 2011 the Company added a new substation at the intersection of 85th Street and Louise Avenue in southwestern Sioux Falls. The new substation is intended to relieve loading on the adjacent Lincoln County Substation. A new 50 MVA transformer and two new 13.8KV feeders provide needed new capacity and voltage support to the growing southwest side of Sioux Falls.

20:10:21:16 PROJECTED ELECTRIC DEMAND

NSPM and NSPW operate an integrated electric generation and transmission system (the "NSP System") serving customers in South Dakota, North Dakota, Minnesota, Wisconsin and Michigan. The forecast of our native energy requirements and peak demand for the State of South Dakota jurisdiction is shown in Table Xcel Energy-SD-1. We produce its long-range "median" forecasts of native energy requirements, summer peak, and winter peak demand. We plan to meet the needs of the integrated NSPM/NSPW generation and transmission system. For planning purposes, we also develop a bandwidth (called semi-high and semi-low scenarios) to supplement our "median" forecasts. These two scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of US economic growth with no basic change in the relationship between the regional and national economies. Table Xcel Energy-1 through Table Xcel Energy-3 show the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP system. Table Xcel Energy-SD-1 shows the South Dakota portion of the NSP System forecast.

The forecast for the NSP System is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial, and large commercial and industrial. Each customer class is modeled independently for the five states included in the NSP System. The native energy requirements are determined by applying a loss factor on total sales. The NSP System peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter "peak loads" provided in Table Xcel Energy-SD-1 represent the South Dakota jurisdiction customer demand at time of total System seasonal peak demand. This "coincident" demand is appropriate for generating capacity requirement forecasting.

It is important to note, however, that a "non-coincident" peak demand must be used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the multi-state NSP System, peak customer demands in our South Dakota service areas can be as much as 10 percent higher than the demands registered during the hour in which the total System peak demand occurs. It is these local "non-coincident" peak demands that determine the need for transmission improvements required for load serving functions.

20:10:21:17 CHANGES IN ELECTRIC ENERGY

Table Xcel Energy-SD-1 shows the projected volume and percentage increase in energy demand for our South Dakota service territory for each year.

Table Xcel Energy-SD-1
Northern States Power Company
State of South Dakota
Forecast of Electric Energy Requirements and Peak Demand

	Summer Peak (MW)	Winter Peak (MW)	Energy (GWh)	Change In Energy (GWh)	% Change In Energy
2012	410	332	2,123		
2013	422	339	2,151	28	1.3%
2014	433	347	2,192	41	1.9%
2015	443	354	2,234	42	1.9%
2016	454	362	2,282	48	2.1%
2017	461	367	2,316	34	1.5%
2018	476	375	2,354	38	1.6%
2019	486	383	2,397	44	1.9%
2020	499	392	2,445	48	2.0%
2021	506	396	2,488	43	1.8%
2022	516	403	2,535	47	1.9%
2023	527	411	2,589	54	2.1%
2024	538	418	2,645	57	2.2%
2025	549	425	2,699	53	2.0%
2026	561	433	2,757	58	2.2%
2027	573	440	2,818	61	2.2%
2028	585	448	2,880	63	2.2%
2029	597	456	2,940	59	2.1%
2030	609	464	3,002	63	2.1%

Average Annual Growth Rate, 2012-2030:

% growth:	**2.2%**	**1.9%**	**1.9%**

Notes:

1). Peak Load is ***coincident*** to the Xcel Energy system peak.
2). Winter Peak = Winter Peak season, 2012 is 2012-2013 winter peak.
3). Peak Load forecast growth from 2022 - 2030 is based on average summer and winter SD peak growth rates from 2012 through 2021.

Table Xcel Energy-1
Northern States Power Company
State of South Dakota
NSP System Net Energy Requirements (MWh)

Year	Semi-Low (MWh)	Median (MWh)	Semi-High (MWh)
2012	44,169,728	45,307,485	46,437,078
2013	43,458,707	44,808,992	46,171,216
2014	43,389,906	44,889,436	46,383,180
2015	43,465,944	45,094,561	46,718,441
2016	43,700,884	45,466,044	47,216,555
2017	43,794,327	45,674,920	47,550,610
2018	43,904,101	45,908,930	47,926,197
2019	43,951,385	46,085,073	48,235,256
2020	44,055,068	46,315,018	48,574,278
2021	44,073,375	46,494,083	48,909,954
2022	44,247,902	46,788,604	49,331,510
2023	44,398,169	47,096,043	49,812,147
2024	44,575,350	47,431,091	50,314,442
2025	44,646,704	47,689,248	50,744,713
2026	44,793,501	48,022,161	51,253,691
2027	44,982,620	48,412,586	51,869,216
2028	45,214,896	48,879,853	52,514,894
2029	45,421,741	49,308,256	53,168,510
2030	45,658,215	49,753,691	53,865,804

Average Annual Growth Rate, 2012-2030:

% growth:	**0.2%**	**0.5%**	**0.8%**

Notes: Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level
NSP System Net Energy Requirements have been adjusted for DSM (Demand Side Management)

Table Xcel Energy-2
Northern States Power Company
State of South Dakota
NSP System Net Summer Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2012	7,748	8,231	8,724
2013	7,734	8,281	8,831
2014	7,765	8,353	8,951
2015	7,808	8,434	9,064
2016	7,852	8,519	9,200
2017	7,891	8,606	9,324
2018	7,953	8,698	9,459
2019	7,972	8,777	9,551
2020	8,049	8,859	9,670
2021	8,066	8,922	9,776
2022	8,113	9,008	9,887
2023	8,188	9,083	10,010
2024	8,219	9,155	10,129
2025	8,234	9,199	10,173
2026	8,233	9,251	10,259
2027	8,268	9,310	10,375
2028	8,272	9,370	10,473
2029	8,272	9,421	10,540
2030	8,320	9,487	10,645

Average Annual Growth Rate, 2012-2030:			
% growth:	**0.4%**	**0.8%**	**1.1%**

Notes: Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level
Net Peak Demand Adjusted for DSM

Table Xcel Energy-3
Northern States Power Company
State of South Dakota
NSP System Net Winter Peak (MW)

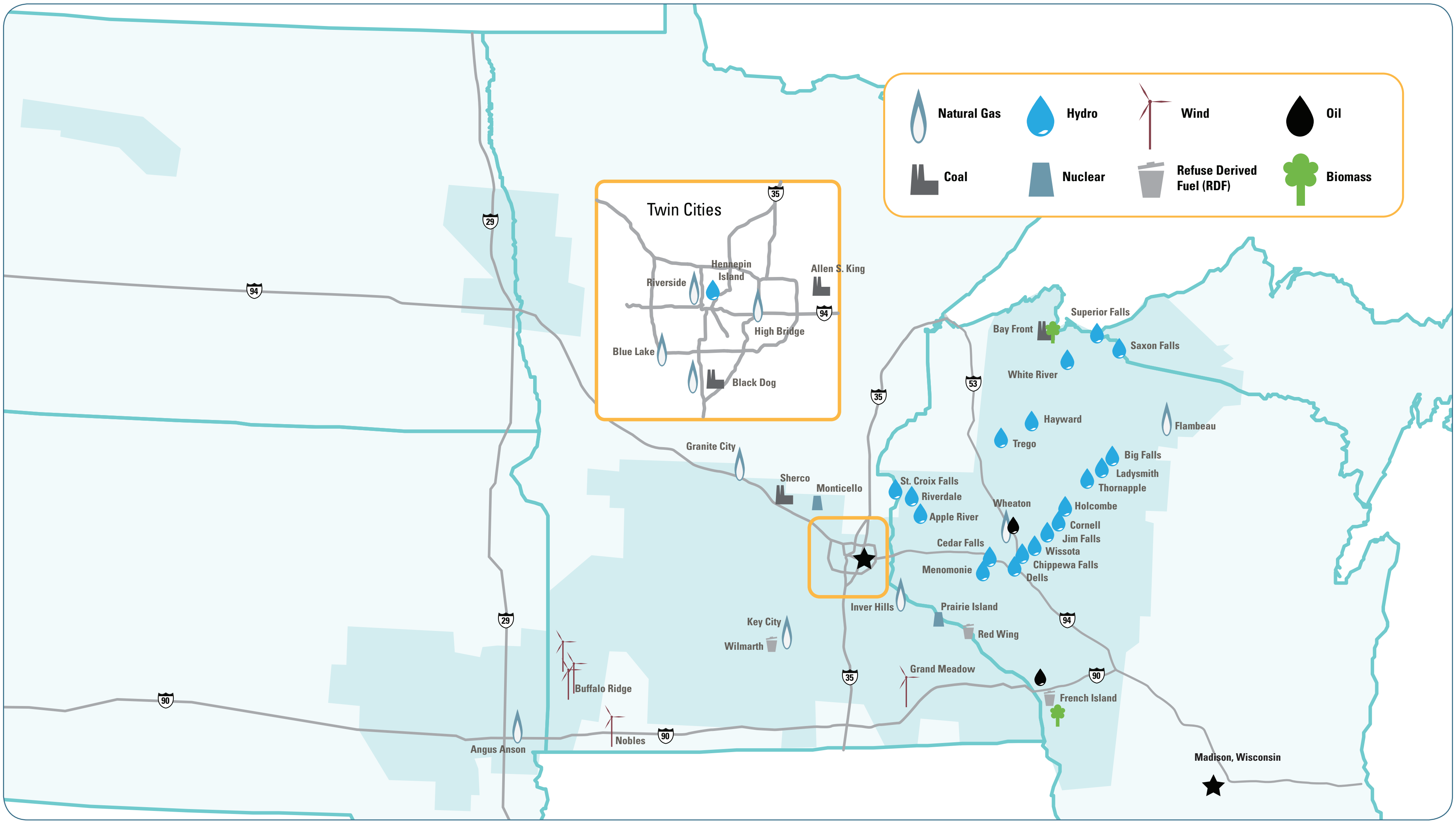
Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2012	6,517	6,836	7,158
2013	6,458	6,830	7,209
2014	6,442	6,873	7,302
2015	6,449	6,919	7,395
2016	6,455	6,963	7,472
2017	6,452	7,011	7,571
2018	6,469	7,057	7,651
2019	6,466	7,098	7,734
2020	6,471	7,141	7,804
2021	6,465	7,175	7,875
2022	6,491	7,222	7,949
2023	6,500	7,250	8,022
2024	6,470	7,271	8,074
2025	6,418	7,270	8,117
2026	6,393	7,281	8,158
2027	6,371	7,295	8,199
2028	6,349	7,308	8,233
2029	6,337	7,323	8,314
2030	6,343	7,348	8,375

Average Annual Growth Rate, 2012-2030:			
% growth:	**-0.1%**	**0.4%**	**0.9%**

Notes: Winter Peak = Winter Peak season, 2012 is 2012-2013 winter peak.
Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level
Peak Adjusted for DSM

Xcel Energy®
RESPONSIBLE BY NATURE™

Upper Midwest Generation Resources



2012 South Dakota Communities Served

E- Electricity U- Unincorporated EU- Electric & Unincorporated

Alexandria **E**	Chancellor **E**	Garretson **E**	Rowena **EU**
Artesian **E**	Crooks **E**	Harrisburg **E**	Salem **E**
Baltic **E**	Dell Rapids **E**	Junius **EU**	Sherman **E**
Bridgewater **E**	Dolton **E**	Lennox **E**	Sioux Falls **E**
Canistota **E**	Ellis **EU**	Marion **E**	Tea **E**
Canova **E**	Emery **E**	Monroe **E**	Unityville **EU**
Canton **E**	Fedora **EU**	Ramona **E**	Vilas **E**
Carthage **E**	Forestburg **EU**	Renner **EU**	Winfred **EU**
Centerville **E**	Fulton **E**	Roswell **E**	Worthing **E**

APPENDIX A
XCEL ENERGY RESOURCE PLAN DOCUMENTS

We filed an update to the Resource Plan on December 1, 2011. A copy of the update is included as Appendix A.

Xcel Energy®

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

[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.

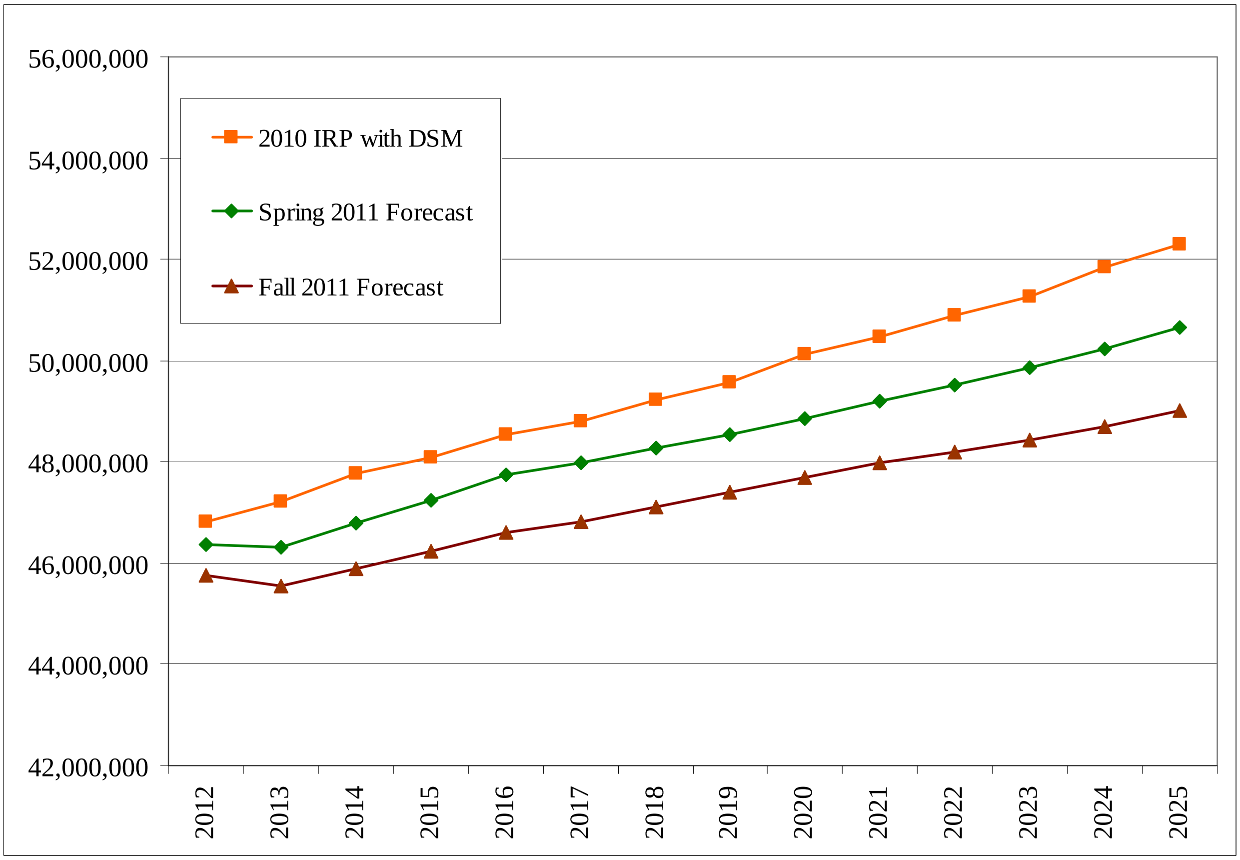
1. *Comparison of System Peak Demand and Median Net Energy Forecasts*

The table and graphs below illustrate the progression of our system peak demand and median net energy forecasts over time.

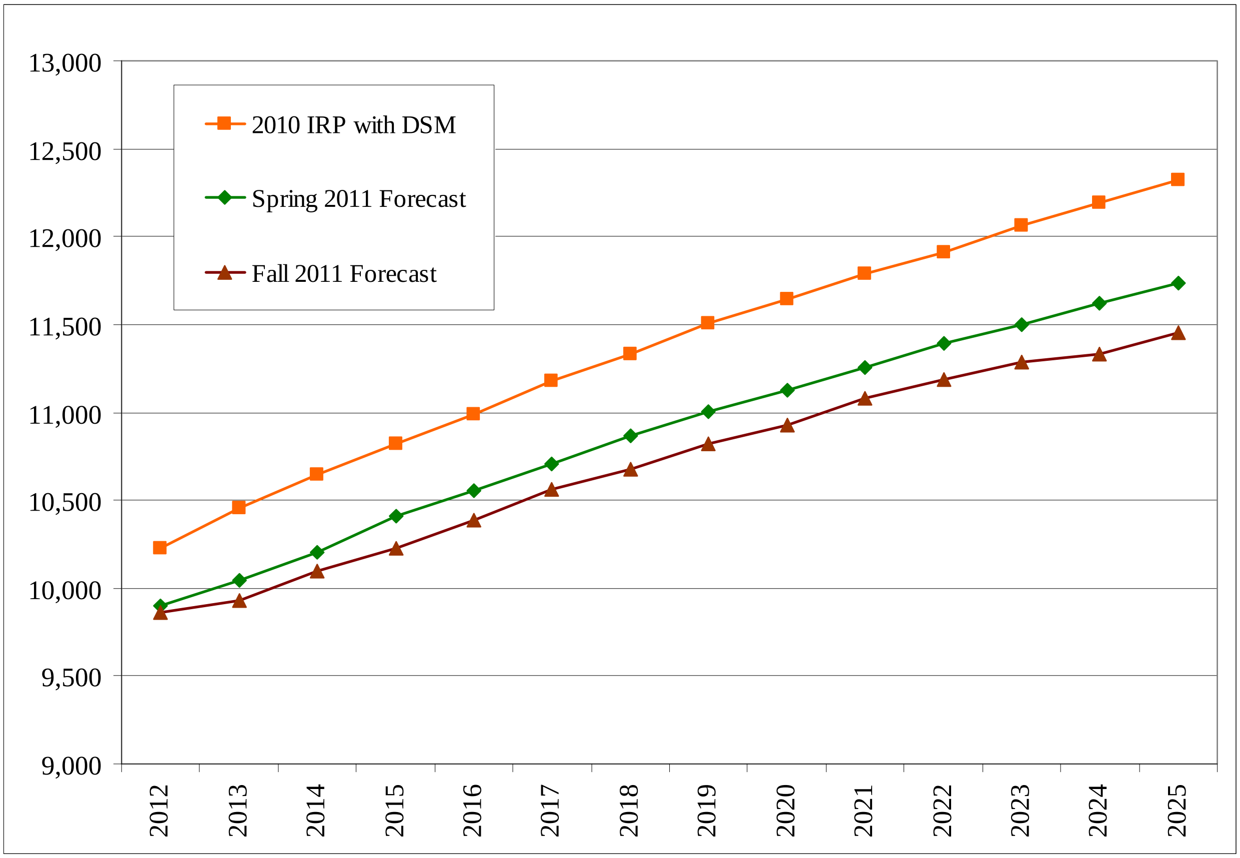
Forecast	**Annual Growth in System Peak Demand**	**Annual Growth in Median Net Energy**
Initial Resource Plan (June 2010)	1.1%	0.9%
Black Dog CON Update (June 2011)	0.9%	0.7%
Resource Plan Update (September 2011)	0.7%	0.5%

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



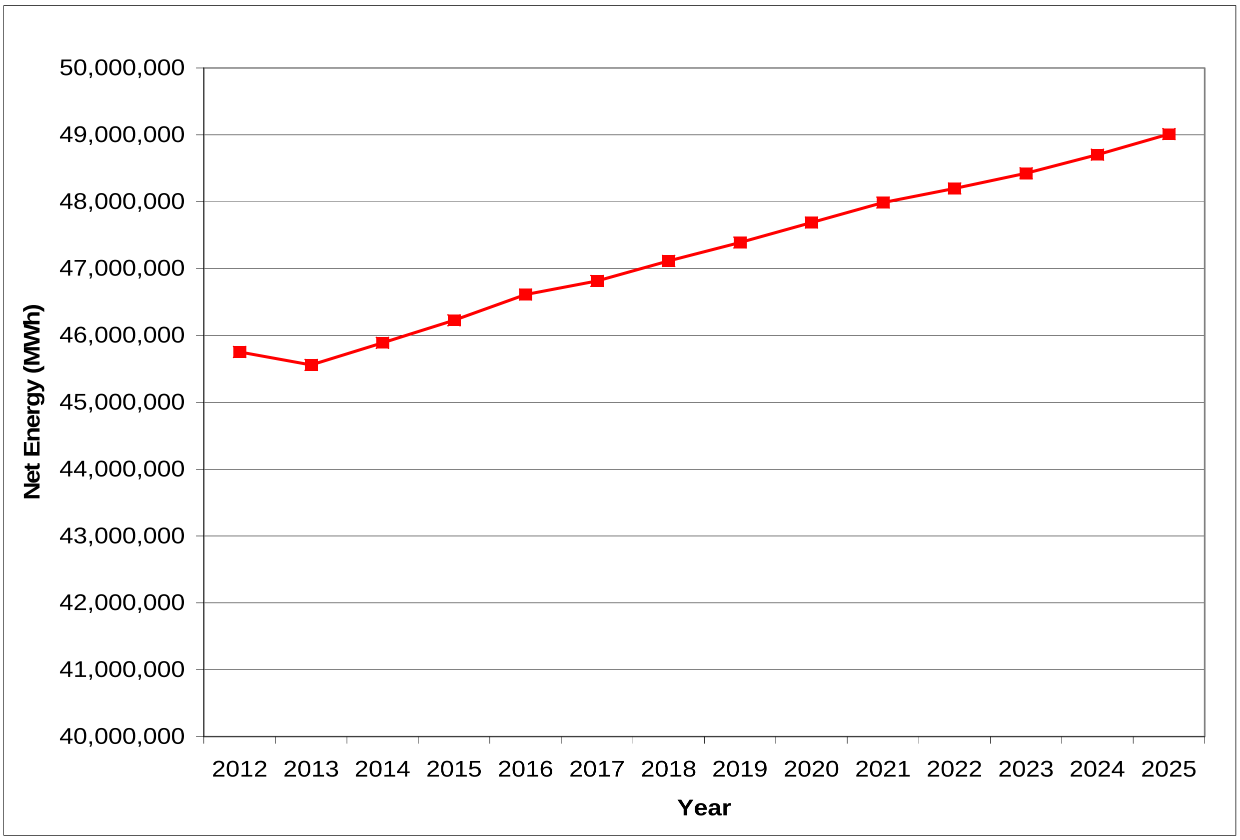
Revised Figure 3.7
Base Peak Demand (MW)
90th Percentile Forecast
Comparison of Current and Previous Demand Forecasts



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.

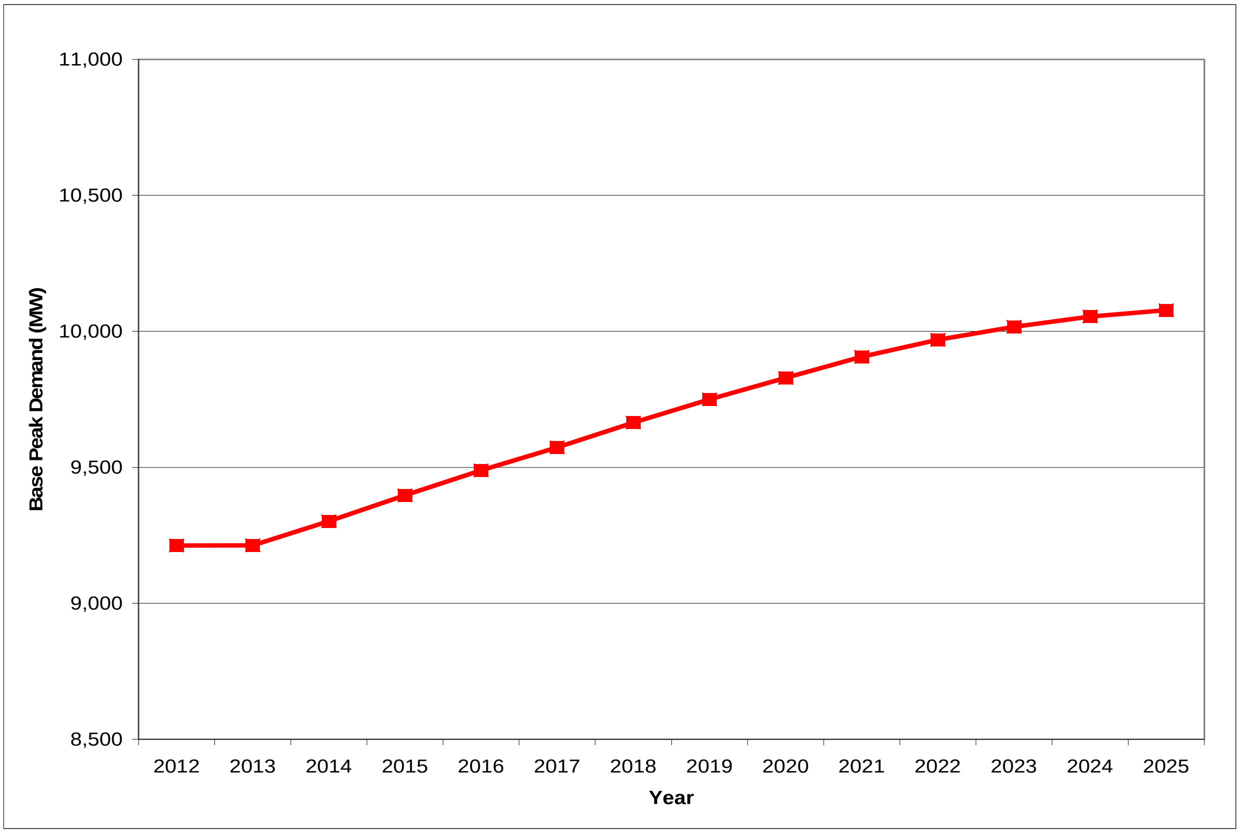
Revised Figure 3.1
Median Net Energy (MWh) NSP Total System
(Includes 1.5% Retail Sales DSM Adjustment)



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

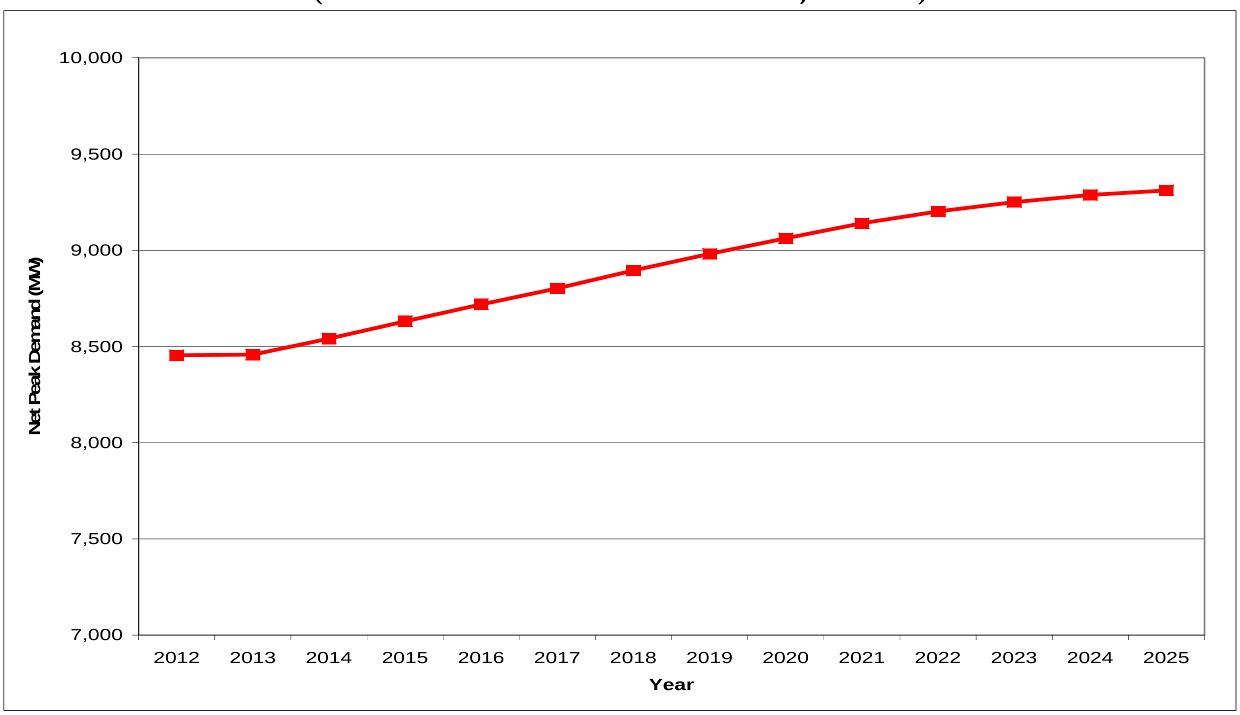
While many of the resources outlined in our initial Resource Plan are still needed, the discussion below explains our resource needs in light of our revised forecasts.

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*

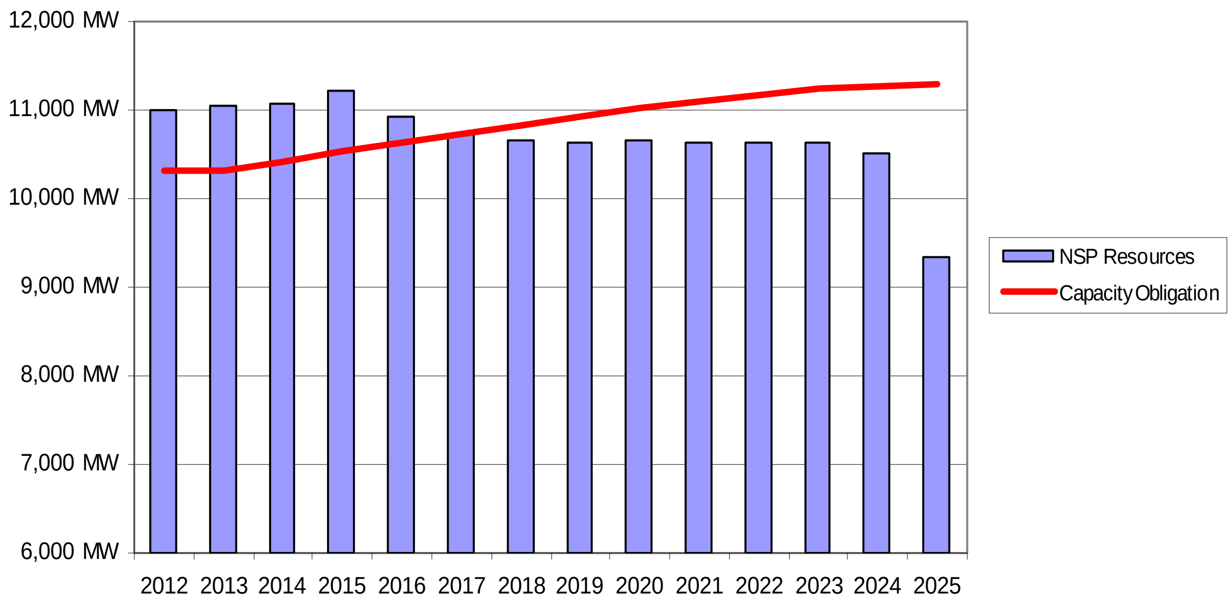
Based on our updated forecasted demand and expected available resources discussed above, we now anticipate new production capacity will be needed starting in 2018. This is three years later than indicated in our initial filing and provides us with additional time to assess the appropriate resources to 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

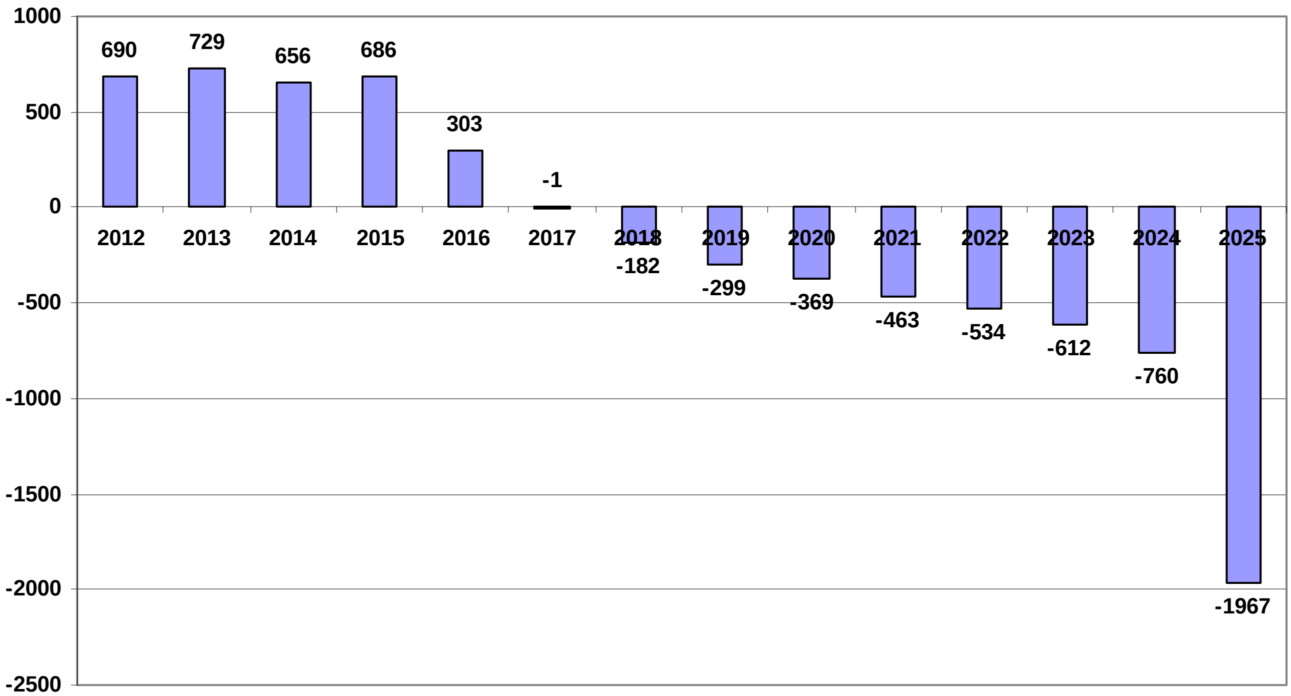
Revised Figure 3.10 presents an updated comparison of our forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions.

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

[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 Sherco 3 8 MW SAF Hydr 3 MW NthShaok 0 MW GoodhuNS 10 MW Fch Isld 3 61 MW DiamondK 0 MW Danielsn 3 MW CommWndN 4 MW BigBlue 5 MW	WIND_PPA 13 MW PrRose 26 MW ND_50 6 MW Monti 1 67 MW CrownHyd 1 MW Borders 19 MW	WIND_PPA 13 MW	WIND_PPA 13 MW P Island 2 55 MW MH375500 375 MW DIV350IN 350 MW	WIND_PPA 13 MW P Island 1 55 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		WIND_PPA 13 MW

Resource Retirements	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
			Key City 4 -14 MW Key City 3 -14 MW Key City 1 -14 MW Granite 4 -14 MW Granite 3 -14 MW Granite 2 -14 MW Granite 1 -13 MW		MH500 -500 MW Div150In -168 MW	Coyote 1 -100 MW	Rapidan -3 MW Div200In -224 MW	Wilmarth 1 -18 MW Viking -2 MW Red Wing 1 -20 MW HERC -34 MW Flambeau 1 -14 MW	WSMorrn -6 MW WindPowr -3 MW Moraine -7 MW KODARAHR -12 MW	MNMethan -5 MW	Fch Isld 4 -64 MW Fch Isld 3 -61 MW Byllesby -2 MW	St.Cloud -7 MW	St Paul -25 MW MNDakota -19 MW	Fch Isld 1 -21 MW Chanaram -11 MW Bayfront 6 -29 MW Bayfront 5 -22 MW Bayfront 4 -19 MW	Stahl -1 MW MNWind -1 MW MH375500 -500 MW LkBnton2 -13 MW Invenerg 2 -161 MW Invenerg 1 -161 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/
____
Lindsey Didion

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No	OFF_SL_10-825_RP-10-825
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_10-825_RP-10-825
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Paper Service	No	OFF_SL_10-825_RP-10-825
B. Andrew	Brown	brown.andrew@dorsey.com	Dorsey & Whitney LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_10-825_RP-10-825
Jeffrey A.	Daugherty	jeffrey-daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_10-825_RP-10-825
Edward	Garvey	garveyed@aol.com		32 Lawton Street St. Paul, MN 55102	Paper Service	No	OFF_SL_10-825_RP-10-825
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	No	OFF_SL_10-825_RP-10-825
Todd J.	Guerrero	tguerrero@fredlaw.com	Fredrikson & Byron, P.A.	Suite 4000 200 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_10-825_RP-10-825

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Hank	Koegel	N/A	enXco	10 Second St., NE, Ste 107 Minneapolis, MN 55413	Paper Service	No	OFF_SL_10-825_RP-10-825
Nancy	Lange	nlange@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Paper Service	No	OFF_SL_10-825_RP-10-825
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_10-825_RP-10-825
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	OFF_SL_10-825_RP-10-825
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Mark	Lindquist		The Minnesota Project	1026 North Washington Street New Ulm, MN 56073	Paper Service	No	OFF_SL_10-825_RP-10-825
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_10-825_RP-10-825
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Paper Service	No	OFF_SL_10-825_RP-10-825

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_10-825_RP-10-825
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_10-825_RP-10-825
Thomas L.	Osteraas	tomosteraas@excelsiorenergy.com	Excelsior Energy	225 S 6th St Ste 1730 Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825
Joshua	Pearson	N/A	enXco, Inc.	15445 Innovation Drive San Diego, CA 92128	Paper Service	No	OFF_SL_10-825_RP-10-825
Kent	Ragsdale	kentragsdale@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_10-825_RP-10-825
Kevin	Reuther		MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	No	OFF_SL_10-825_RP-10-825
Matthew J.	Schuerger P.E.		Energy Systems Consulting Services, LLC	P.O. Box 16129 St. Paul, MN 55116	Paper Service	No	OFF_SL_10-825_RP-10-825
Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC	15347 Boulder Pointe Road Eden Prairie, MN 55347	Paper Service	No	OFF_SL_10-825_RP-10-825
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_10-825_RP-10-825
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_10-825_RP-10-825
Douglas	Tiffany	tiffa002@umn.edu	University of Minnesota	316d Ruttan Hall 1994 Buford Avenue St. Paul, MN 55108	Paper Service	No	OFF_SL_10-825_RP-10-825

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No	OFF_SL_8-509_1
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_8-509_1
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_8-509_1
Katherine	Becker	becker@mdh-law.com	Madigan Dahl & Harlan	N/A	Electronic Service	No	OFF_SL_8-509_1
B. Andrew	Brown	brown.andrew@dorsey.com	Dorsey & Whitney LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_8-509_1
Bianca	Calatayud	calatayud@mdh-law.com	Madigan, Dahl & Harlan	N/A	Electronic Service	No	OFF_SL_8-509_1
Carol	Duff	N/A	-	1024 West 4th Street Red Wing, MN 55066	Paper Service	No	OFF_SL_8-509_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_8-509_1
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_8-509_1
Karen Finstad	Hammel	Karen.Hammel@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota Street St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_8-509_1
Thomas P.	Harlan	harlan@mdh-law.com	Madigan, Dahl & Harlan, P.A.	222 South Ninth Street Suite 3150 Minneapolis, MN 55402	Paper Service	No	OFF_SL_8-509_1
Arshia	Javaherian	arshiajavaherian@alliantenergy.com	Interstate Power and Light.	PO Box 351 Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_8-509_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	OFF_SL_8-509_1
Michael	Lewis	michael.lewis@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_8-509_1
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_8-509_1
Richard	Luis	Richard.Luis@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper Service	No	OFF_SL_8-509_1
Paula	Maccabee	Pmaccabee@visi.com	Just Change Law Offices	1961 Selby Avenue St. Paul, MN 55104	Paper Service	No	OFF_SL_8-509_1
Phil	Mahowald	pmahowald@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Road Welch, MN 55089	Paper Service	No	OFF_SL_8-509_1
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_8-509_1
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Paper Service	No	OFF_SL_8-509_1
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Paper Service	No	OFF_SL_8-509_1
Patricia	Silberbauer	Pat.Silberbauer@ag.state.mn.us	Office of the Attorney General-DOC	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	Yes	OFF_SL_8-509_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_8-509_1
Michael	Wadley	mike.wadley@xenuclear.com	Prairie Island Nuclear Generating Plant	1717 Wakonade Drive East Welch, MN 550899642	Paper Service	No	OFF_SL_8-509_1
Brian	Zelenak	brian.r.zelenak@xcelenergy.com	Xcel Energy	414 Nicollect Mall 7th Floor Minneapolis, MN 554011993	Paper Service	No	OFF_SL_8-509_1

NSP Transmission Lines – 115 kV and above

2012