UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Citizens Energy Task Force and
Save Our Unique Lands,

Complainants,
v. **Docket No. EL13-49-000**

Midwest Reliability Organization (MRO);
Midwest Independent Transmission System
Operator, Inc. (MISO); and as Applicants
for the CapX 2020 Hampton-La Crosse
Transmission Project Xcel Energy, Inc.
(Northern States Power Company, a
Wisconsin Corporation, Northern States Power
Company, a Minnesota Corporation, d/b/a Xcel
Energy); Great River Energy, a Minnesota
Cooperative Corporation; Dairyland Power
Cooperative, a Wisconsin Cooperative
Corporation; Wisconsin Public Power Inc., a
Wisconsin corporation;

MOTION FOR LEAVE TO ANSWER AND ANSWER OF CITIZENS ENERGY TASK FORCE AND SAVE OUR UNIQUE LANDS

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (hereinafter "Commission"), Citizens Energy Task Force and Save Our Unique Lands (hereinafter "CETF/SOUL") submits this Motion for Leave to Answer and Answer (hereinafter "Answer") in response to the Answer of Respondent Utilities, Midwest Independent Transmission System Operator, Midwest Reliability Organization, MISO Transmission Owners, Public Service Commission of Wisconsin, Southern Minnesota Municipal Power Agency, and Rochester Public Utilities filed on March 21, 2013, and the April 1, 2013 comments of the Minnesota Public Utilities Commission.

I. INTRODUCTION

The Respondent Utilities provide information that should be closely considered by the Commission. To a point, they are correct in their claim that studies regarding "new generation" were not part of the CapX 2020 Phase I review, and that their Corridor Study released in 2009 indeed does not address system instabilities caused by the addition of the CapX 2020 Hampton – Rochester – La Crosse transmission project. However, while not modeled, Respondent Utilities and MISO would have known of generation plans that would lead to the tipping point, which their studies discuss.

Respondent Utilities provided Appendix H with their Answer, which gives further insight into the specific issue raised by Complainants, first, that the radial nature of the Hampton – La Crosse transmission project does create stability issues; second, the recognition that a 345 kV radial line is "only a piece of a more comprehensive solution;" and then expressly stating that if the radial line were built before the extension eastward to Madison, it would require significant additional lower voltage system upgrades.

The La Crosse 161 kV Load Serving Study contained a "Regional 345 Option Analysis" which evaluated only Prairie Island to other 345 kV systems, including Columbia (2), West Middleton (2), and Salem (1). While not conclusive, these studies reviewed five alternatives, and eliminated three, leaving only the Prairie Island to Rochester to North La Crosse to Columbia and the Prairie Island to Rochester to North La Crosse to West Middleton, both of which are essentially "Twin Cities to Madison" and neither of which are radial lines terminating in La Crosse.

Rather than refute the Complaint, the Answer of Respondent Utilities' adds to the evidence of a systemic electrical problem in moving forward with a radial line ending in La

Crosse. None of the studies produced or referenced by Respondent Utilities' qualified engineers address an electrical fault of the 345 kV radial line and the impact on the transmission system. None of the studies have addressed whether the addition of a La Crosse – Madison line would alleviate the instability problem or address the impact that a fault of all or part of the extended Hampton-Rochester-La Crosse-Madison transmission line would have on the transmission grid.

II. <u>MOTION FOR LEAVE TO ANSWER</u>

Pursuant to Rule 212[1] and 213[2] of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, CETF/SOUL request leave to file this Motion and Answer to the Answers and Motions to Intervene and Comments of Respondent Utilities, Midwest Independent Transmission System Operator, Midwest Reliability Organization, MISO Transmission Owners, Public Service Commission of Wisconsin, Southern Minnesota Municipal Power Agency, and Rochester Public Utilities filed on March 21, 2013, and the April 1, 2013 comments of the Minnesota Public Utilities Commission.

Responsive Answers are generally prohibited, but there are situations where the Commission does permit Answers, particularly where the answer would provide useful and relevant information to assist the Commission in making its decision, or where the Answer corrects factual errors of responding parties and clarifies issues in the Complaint before the Commission.[3] CETF/SOUL request that the Commission accept our Answer because it is narrow in scope and it will correct factual errors and clarify the issues raised in the Complaint, both of which will assist the Commission in the decision making process.

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1 18 C.F.R. §385.212 (2012).
2 18 C.F.R. §385.213 (2012).
3 See e.g., Order, p. 19, *Am. Transmission Co., LLC v. Midwest Independent Transmission System Operator, et al.*, 142 FERC ¶ 61,090 (2013).

III. ANSWER

Complainants request leave to file this answer regarding several points raised by Respondent Utilities and other Commentors/Intervenors.

A. Procedural Issues

1. Complainants have not utilized engineers because the Complaint is based on Respondent Utilities' own studies, performed by Respondent Utilities "qualified electrical engineers."

Complainants have not utilized engineers because the Complaint is based on the Respondent Utilities' own studies and conclusions, performed by their own qualified electrical engineers, who provided credible technical and engineering analysis in the studies and testimony filed by the Applicants in support of their transmission projects.

2. Respondents named and served were the CapX 2020 applicants

Respondent Utilities objects to the choice of Respondents. The Respondents named were those utility applicants in Minnesota Certificate of Need and Wisconsin Certificate of Public Convenience and Necessity dockets.[4]

3. Complaint is not untimely because Respondents' current project relies on outdated information and Respondents' are presently withdrawing from projects based on changed circumstances and updated data.

Respondent Utilities and others claim that the Complaint is untimely because Complainant "relies on studies published at least four years ago." Respondent Utilities Answer at 14. Respondent Utilities also infer that Complainant is confused, and that the Corridor Study is not for "existing generation" but to determine what is necessary to add new generation. Id., 4.

> The Complaint relies heavily on certain studies that identified and analyzed the next increment of transmission expansion that would be necessary after the Twin Cities – La Crosse Project is placed in service and with thousands of additional megawatts of new generation added to the system. Specifically, the Study Report

[4] Minnesota PUC Docket E02, ET-002/CN-06-1115 and Wisconsin PSC Docket 05-CE-136 respectively.

> of Electric Transmission Corridor Upgrade from Granite Falls Area to Southwest Twin Cities ("Corridor Study"), the Minnesota RES Update Study Report ("RES Update"), and the Western Wisconsin Transmission Reliability Study ("WWTRS"), each assumes the Twin Cities – La Crosse Project in all underlying system models as well as the need to accommodate generation levels over and above those studied for the Twin Cities – La Crosse Project.

Respondent Utilities Answer, p. 4.

However, the entire CapX 2020 Phase I build out, including both Hampton – La Crosse and La Crosse – Madison was premised on extreme increases in demand and the addition of massive amounts of generation, the latter of which was also a focus of the Corridor study. The need for the Hampton-La Crosse line and all of CapX relies on studies based on 2003 and 2004 data published in 2005. We now know these to be unreasonably high forecasts and very high levels of presumed new generation. See Supra, Section B 2, Decreased Demand Known to Applicants.

The timing of Complainant's Complaint is reasonable as the Respondents have justified project need on the same old studies where new information is now available and the impacts of the recession are now clear. Meeting Minnesota's RES Mandate, which is for all intents and purposes is already met, is not a justification for transmission, nor a justification for adding transmission in Wisconsin.

4. Complaint is not untimely because MISO has approved projects in subsequent MTEPs that depend upon projects approved in MTEP 08, nor is it moot because future projects have been approved that may address stability concerns.

The approval or rejection of a project lies with a State's jurisdiction. Even after approval by Public Utility or Service Commissions, projects may be challenged through the Commissions' administrative process and the courts. See e.g., Comments and Intervention of Wisconsin Public Service Commission. Respondent Utilities and MISO cannot usurp this very clear and understood State right by claiming uncertainty. To remove any uncertainty, Respondent Utilities and MISO can either present dependent segments or projects together, capturing their total costs and Environmental Impact, wait for State approval on "foundational projects" prior to determining next steps, or accept the risk inherent in a defective process. Another option would be to change the law or regulations, or change the MISO process, although not retroactive.

The complaint is not "moot" due to the MISO MTEP2011 approval of Badger Coulee, which may address instability issues and may also capture claimed economic benefits, but these are not yet demonstrated facts because the project is not even an applied for in the State of Wisconsin. If connected sufficiently to render the Complaint moot, this would validate Complainants claim of improper segmentation, and would necessitate an environmental impact statement and economic analysis of both lines together, neither of which gave been done.

5. Complainant is not untimely because Complainants are not members of MISO, and have had no opportunity for participation at MISO in MTEP decision-making and Complainants have been actively involved at the state level when opportunities for participation is available.

Respondents claim, based on the Commission's dismissal of ATC's Complaint against MISO, et al, that Complainants "should have advanced this argument during the planning process, when MISO actively engaged with stakeholders to develop regional expansion plans."[5] However, the fact situations of the Xcel Energy and American Transmission Company's ownership issues over the Hampton – La Crosse and Badger Coulee transmission lines is different than that of CETF/SOUL's Complaint. Unlike American Transmission Company, Complainants are not regarded as "stakeholders" by MISO or the Respondent Utilities, and have

[5] *American Transmission Company LLC v. Midwest Independent Transmission System Operator, et al,* 142 FERC ¶ 61,090 at P 53.

no opportunity to participate in the MTEP process. The FERC Order at the paragraph 53 as cited by Respondents states:

> In the Complaint, American Transmission does not challenge the validity of Appendix B of the Transmission Owners Agreement or Attachment FF of the Tariff, nor does American Transmission challenge how MISO applied these documents in the 2008 or 2011 MTEP and the project designations in Appendix A of the respective reports. Instead, American Transmission now requests that MISO apply Appendix B, section VI of the Transmission Owners Agreement retroactively to enable American Transmission to own and construct 50 percent of the Twin Cities – La Crosse Line based on an assertion that the two segments consisting of the Twin Cities – La Crosse Line and the La Crosse – Madison Line, once completed will form a single 345 kV interconnection, even though they were approved by MISO in different MTEP planning cycles. We believe that American Transmission should have advanced this argument during the planning process, when MISO actively engaged with stakeholders to develop its regional expansion plans. We therefore defer to MISO's designation of ownership for the project to Xcel and the other CapX 2020 participants.[6]

ATC is a stakeholder at MISO, and CETF/SOUL are not. Stakeholders who can participate in the MTEP process are limited by MISO policy to a chosen few:

> The entities comprising these stakeholder groups are not members of MISO; rather, they are representatives of public consumer groups and other stakeholder groups serving on the Advisory Committee, which have been chosen by recognized consumer, environmental and other stakeholder organizations having an interest in the activities of MISO.[7]

In addition to being a stakeholder, senior management of ATC has significant historic and current influence over MISO planning both generally and in the MTEP. ATC's original CEO was a formative member of MISO and senior management currently leads one of MISO's two key planning committees. ATC's former counsel is President Obama's Senior Advisor to the Secretary of Energy and co-chair of the Rapid Response Team for Transmission.[8]

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[6] Id.

[7] MISO Stakeholder page: https://www.midwestiso.org/Library/Repository/Communication%20Material/Corporate/Current%20Members%20by%20Sector.pdf

[8] Obama Administration Officials to Announce Job-Creating Grid Modernization Pilot Projects, October 4, 2011, online at http://energy.gov/articles/obama-administration-officials-announce-job-creating-grid-modernization-pilot-projects

Those chosen as "ENV'L/OTHER STKHDR GROUPS (Non-Members)" by MISO are also those that, with one or two exceptions, have received substantial funding for promotion of transmission and are frequent participants in transmission promotional activities, and three of which intervened in support of CapX 2020's Certificate of Need Application in Minnesota.

VII. **ENV'L/OTHER STKHDR GROUPS (Non-Members)**

1. **Citizens Action Coalition of Indiana**
2. **Clean Wisconsin**
3. **Environmental Law & Policy Center**
4. **Fresh Energy**
5. **Great Plains Institute**
6. **Izaak Walton League of America**
7. **Project for Sustainable FERC Energy Policy**
8. **Wind on the Wires**

These stakeholder groups do not represent the interests of CETF/SOUL.

Stakeholder participation has been an issue under FERC Order 890, evidenced in comments by the Organization of MISO States:

> However, the reality is that the practical ability of many stakeholders, including retail customers and those representing the interests of retail customers is limited. Transmission planning and energy industry practices generally are evolving rapidly. The Commission must understand that stakeholder resources, particularly those within state commissions and other customer and public interest representatives, are spread thin.

Attachment A, p. 8, Comments of Organization of MISO States, Order 890 FERC Docket AD09-8-000 (emphasis added).

In the FERC Complaint docket referenced by Respondent Utilities,[9] ATC challenged ownership of a transmission project in which it participated in developing, participated in the studies, and in the MTEP process itself. CETF and SOUL are not stakeholders and are unable to participate as ATC did in that docket. The FERC decision regarding ATC's challenge of MISO declaration of ownership in the Hampton-Rochester-La Crosse transmission line is not applicable

[9] *American Transmission Company LLC v. Midwest Independent Transmission System Operator, et al,* 142 FERC ¶ 61,090.

to non-participating non-members of MISO. To hold citizens to the same standards of early involvement as MISO stakeholders, policy formers and planning leaders would be absurd.

The MTEP process is not an agency proceeding, there is no review process or timetable for such review, and "stakeholders" are severely limited in number, scope of interests and impact. Only when a project moves to State planning and approval is there a mechanism for the public to become informed and involved. Complainants have been criticized for their steadfast involvement at the State level for many years, having focused on CapX2020 and its dependent segment, Badger Coulee, from the pre-application, contested case, reconsideration and judicial review. Complainants filed the complaint with FERC as the logical next step after exhausting all administrative remedies in Minnesota and Wisconsin. At this time believe that FERC is the appropriate venue for this Complaint.

6. **Economic harm is measured at minimum as the cost of the project**

Respondent Utilities claim that the CETV/SOUL Complaint is deficient because it does not quantify the cost of harm. That expert analysis is something not available to CETF/SOUL, an expense that is cost prohibitive to intervening organizations. However, Respondent Utilities ' experts have quantified a minimum cost of harm, which is the $507 million cost estimate for the Hampton – La Crosse transmission project.. That $507 million cost will be borne by ratepayers through the FERC approved MISO tariff, with the cost allocation for a Multi Value Project set at 100% postage stamp to load. MISO Tariff Attachment FF.

B. Substantive Issues

1. **Studies did not address impact of failure of CapX Phase I projects**

Respondents find fault with the Complaint, stating that "Complainants have not met their burden to establish that the Project creates any reliability problems," and citing to studies including the Corridor Study, the CVS study, the WWTRS, etc. It is the burden, instead, of a project proponent to demonstrate that the project will not cause any reliability problems. Respondent Utilities have yet to conduct studies that show that the line will not create reliability issues should the line fail.

All of the studies referenced by Complainant and Respondent Utilities focused on non-CapX 2020 project transmission line contingencies, specified a line in question and modeled an outage and identified contingencies. Not one study addresses the obvious issue of what would occur to the grid if the CapX 2020 project, in whole or in part, were to fail. Where would this power go? This question has not been addressed, other than to state that additional work must be done including operating guides and bolstering the lower voltage system. See e.g., SE Minnesota/SW Wisconsin Study. The CapX 2020 projects were approved with no regard for the impact of their construction and operation of the project on the transmission system and only addressed what contingencies could be solved by adding the project. Respondent Utilities Answer, p. 4; see e.g. p. 16.

Applicant is correct in that Complaint is citing Respondent Utilities CapX 2020 Phase I studies, and later studies performed to identify the next increment of transmission expansion, and these studies are cited because these are the only studies that support and justify CapX 2020 transmission. The "next increment of transmission expansion" is not the subject of the Complaint, it is that the studies that serve as the basis for CapX 2020 Phase I are inadequate, that planning and electrical flaws exist when the line ends at La Crosse, and that these inadequacies remain in the studies that followed. See /SE MN/SW WI Study, p. 1, 5Appendix A-2, Application, CapX 2020 CoN, 06-1115)

2. **Decreased demand known to Applicants and Errors Identified in Peak Demand Calculations**

Circumstances change. Decreased demand has been the turning factor in other Independent System Operator determinations that a project is no longer needed. For example, PJM has withdrawn the MAPP project, first a segment and later the entire project, and also the PATH project. Both were large projects enmeshed in a many year process, and both were determined not to be needed given economic changes that also changed “need” for the projects. Whether the changed circumstances occur prior to or after MTEP “approval,” the planning process requires reiteration, or as PJM terms it, “retooling,” and the economic changes should be taken seriously. Information about decreased demand was known to the Applicants, and should have been known to MISO during the MTEP 08 process.

CapX 2020 was based on a presumed need for 4,500 – 6,300 MW, or 8,000MW of new generation considering line losses, to cover the forecasted 2.49% annual growth rate.[10]

Control area	2009 load level (2004 MAPP Series) (MW)	Yearly growth rate (%)	Calculated 2020 load level (MW)
ALT (West)	3265.3	1.60	3888.2
Xcel Energy (North)	9632.6	2.68	12885.1
MP	1507.3	1.70	1814.4
SMMPA/RPU	330.0	2.70	442.4
GRE	2833.5	3.27	3943.2
OTP/MPC	1677.2	2.70	2248.3
DPC	954.7	2.60	1266.2
Total	20200.6	Ave. = 2.49%	26487.8

Table 1 – CapX 2020 Anticipated Area Growth

Id., Attachment B, CapX 2020 Technical Update, p. 5.

[10] Attachment B, p. 5; see also p. 1, CapX 2020 Technical Update, Minnesota CapX 2020 Certificate of Need Application Appendix A-1, Docket ET-2, E-002/CN-06-1115. Available online: http://www.psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=160027

As noted in the Complaint, demand has dropped precipitously, rendering CapX 2020 "forecasts" such as this preposterous.

> As noted by the MPUC, CETF intervened in the Minnesota Certificate of Need docket: CETF argues that incorporating this new evidence into Applicants' forecasts would produce a demand forecast for 2020 that would be less than the lowest amount considered in the 2020 Vision Study forecasts which provide the engineering basis for the proposed projects. This analysis, CETF argues, undermines Applicants' rationale for the proposed projects as well as the foundation for the ALJ's Report.

MPUC Order p. 10, Attached exhibit to MPUC Intervention and Comment, March 28, 2013.

Applicants and MOES[11] characterized the decreased demand as "short term," which was adopted by the Administrative Law Judge:

> The ALJ found that "reopening the record to analyze short-term consumption will not materially affect the longer term projection," and a "short term drop in consumption will have little impact on the longer range forecasting of peak demand developed for the certificate of need proceeding."

Id., p. 10.[12] We now know this is not short term.

Respondents have admitted "Change of Circumstances," withdrawing from projects that are no longer needed because circumstances have changed so significantly,[13] and large transmission build-outs are being cancelled elsewhere, particularly in PJM. Applicants have made several filings regarding "Change of Circumstances" in Minnesota, citing decreased need. Xcel Energy, Minnesota's largest utility, has filed a Resource Plan Update detailing decreased demand. Xcel has filed Notice of Changed Circumstances in two Certificate of Need dockets, withdrawn from the Black Dog Certificate of Need project and the further expansion of generating capacity at the Prairie Island Nuclear Power Plant. Id.

Xcel Energy's own demand projections in its Integrated Resource Plan (IRP) are also not

[11] Minnesota Office of Energy Security, Dept. of Commerce.
[12] Citing Order Denying Motion for Limited Discovery and to Reopen Hearing (December 10, 2008) at 2; see also ALJ's report, Findings 185 – 200.
[13] Attachment C, Xcel Energy Resource Plan Update, MPUC Docket E-002/RP-10-825, see also Attachment F, MPUC IRP Order, p. 3, Docket E002/RP-10-825.

as high as those in the CapX 2020 studies, rather than a 2.49% increase, instead projecting only 0.7% growth in peak demand and 0.5% in net energy:

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%

Attachment C, Xcel Energy Resource Plan Update, p. 14.

Xcel recent Earnings Call reflected this reality:

Benjamin G. S. Fowke – Chairman, Chief Executive Officer and President

Well, everything -- overall, on the residential side, it's safe to say everything is pretty flat. So then you move to the C&I side, and actually, the strongest C&I growth was in Wisconsin this year, followed by Texas, I think, followed by Colorado, which had small growth. And then we were -- we didn't grow at all in Minnesota for a number of reasons. That said, the economy definitely saw some signs of improvement in 2012. Housing permits were up. Job growth was better than the national average. Unemployment was equal to or better than the national average. So I think the economies are in decent shape across all our jurisdictions. Doesn't necessarily mean it translates to high sales growth. And that's consistent with our forecast. I mean, we're not anticipating that we're going to see a tremendous rebound in sales, even as the economies start to improve. I mean, I think, that's our new normal, frankly.

XEL Earnings Call, January 31, 2013[14]. Demand is down, also verified in Xcel Energy's SEC 10-K filing, from 9,792 to 9,475, forecasted to drop to 9,215 in 2013.[15]

Despite the demonstrated drop in peak demand, Respondent Utilities have skewed the forecasts by use of non-coincident peak rather than coincident peak for load service planning, which was challenged in the Wisconsin CPCN proceeding. Coincident peak load is the highest

[14] Transcript of Earnings Call available online at: http://seekingalpha.com/article/1147511-xcel-energy-management-discusses-q4-2012-results-earnings-call-transcript
[15] Attachment G, p. 6, Northern States Power 10-K (selected).

aggregate load for all substations within the study area at a particular snapshot in time. Non-coincident peak loads are the sum of the highest load at each substation or feeder (bus), whenever it occurred, not in any way connected in time to the peaks of other substations or feeders in the study area. Coincident peak load would be lower than non-coincident peak load because the substation/feeder peaks occur at different times. Use of non-coincident peak loads in planning and design of the Hampton to La Crosse line gives an overstatement of demand and result in overbuilding, an overly robust and more costly project than necessary under coincident peak load, and allowing construction of projects at the expense to landowners and ratepayers for purposes of other than serving load, such as increasing market capacity.[16]

La Crosse load service was at issue in the Wisconsin CPCN proceeding, and the grant of the CPCN was based in large part on Xcel's out-of-service status for its French Island 3 unit, making it unavailable for peak demand. The Minnesota PUC recently approved Xcel Energy's IRP which included a provision that the French Island 3 unit would be returned to service.[17] Xcel has also been directed to utilize demand side management and offer discounts for interruptible service to reduce energy sales by 1.3% or more. Id. This is at odds with the Wisconsin CPCN decision regarding the Hampton – La Crosse transmission project, and both of these issues were raised by CETF/SOUL in its Motion for Rehearing in Wisconsin.

Respondent Utilities fail to note that another of the stated assumptions for the CapX 2020 transmission build-out is the presumed significant generation additions in the region based on the Midwest Independent System Operator (MISO) queue at that time, which in the CapX expansion area totaled 16, 712 MW of generation. These are the generation expectations used in development of CapX in the 2005 Technical Update, and in support of its 2007 and 2010

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[16] Hahn Direct, p. 8-13, Wisconsin CPCN Docket 05-CE-136.
[17] Attachment F, PUC Order, Xcel Energy IRP 10-825, March 3, 2013.

Minnesota PUC and Wisconsin PSC applications, issued in 2009 and 2012, many years later. The generation in the MISO queue is also the generation on which the Corridor Study is based. The generation presumed is heavily weighted in Minnesota and Wisconsin, but dispersed across the Midwest region: North and South Dakota (840 MW and 1005 MW), Iowa (1005 MW), Minnesota (6566 MW) and Wisconsin (6559 MW).

The 2005 Technical Update that is the basis for CapX 2020 took this high level of generation, 16, 712 MW, into account at that time to determine what transmission could be needed both generally and specifically presuming a high amount of wind generation to be added. See Id., Diagram 3 – MISO QUEUE, Potential Generation Areas. The CVS Study presumes this same level of generation, not "new generation," and states that a new transmission line is needed east of Minnesota.. CVS Study, p. 6; see also Corridor Study p. 13 of 205; RES p. 9-10.

Where demand has decreased so significantly that projects are being canceled and project proponents are withdrawing from projects, and where information was known to the applicants and should have been known to MISO, the need for these projects is open to question.

3. Compliance with RES mandates is not at issue, it is presumed.

Respondent Utilities also claim that Complainants are in error because utilities need the transmission additions to fulfill their Minnesota Renewable Energy Standard mandates:

> The Corridor Study, RES Update, and CVS were performed to identify additional transmission investments that, depending on assumptions, may be needed to accommodate the new generation necessary meet Minnesota's renewable energy standards between 2016 and 2025.

Respondent Utilities Answer, p. 21. Respondent Utilities repeat this regarding the RES Study:

> Like the Corridor Study, the RES Update was performed to identify additional future incremental additions to the transmission system that would be needed to accommodate the additional generation needed to meet the Minnesota renewable energy standard.

Respondent Utilities Answer, p. 23; See also Respondent Utilities Affidavit of Kline.

Contrary to these statements that transmission is necessary to satisfy Minnesota's renewable energy standard, the studies presume the same 4,000 – 6,000 MW of new generation as presumed initially for CapX 2020 build-out despite the presumed satisfaction of the RES. CVS, p. 11. "The CapX 2020 lines and future lines under study were not part of the model as the export levels were set." Corridor Study, p. 11 (p. 105 of 205). It is not clear what "new generation" is at issue.

Despite the claim of "need" for "Minnesota" RES, use of the Twin Cities as a sink for this generation was found to be a problem:

> The primary drawback, therefore, to using the Twin Cities generators as a sink is the possibility of overestimating the real facility needs. The transformers and lines and voltage support devices may be specified as being needed based on the assumption that there will be no reliable path to deliver generation to the Midwest ISO-wide footprint. But if a line is built across Wisconsin to allow delivery to that greater footprint, the Twin Cities facilities may be somewhat overbuilt.

RES Update/Corridor Study, p. 16 (p. 110 of 205). This belies the claim that compliance with Minnesota's RES is at issue and a purpose for the upgrades.

Further, Minnesota's renewable energy milestones have been met and exceeded by Xcel Energy, the largest of Minnesota utilities and the Utility which, as a nuclear generating utility, has the largest percentage Renewable Energy Requirement.

> On February 4, 2013, Xcel filed a letter of intent to issue a Request for Proposals (RFP) to procure up to 200 MW of wind generation. According to Xcel:
>
> "With the extension of the federal renewable electricity production tax credit (PTC) effective January 2, 2013, we believe it is prudent to assess opportunities for additional wind resources on our system at this time to determine if there are cost-effective wind projects that could provide long-term value to our customers."
>
> Xcel expects to issue the wind RFP as soon as February 15, 2013; the PTC extension carries a requirement for wind projects to begin construction by the end

> of 2013. Xcel outlines a projected timeline for the RFP process, which indicates a "Decision Report" will be filed in July 2013.
> Since Xcel has "enough renewable energy credits to meet RES compliance requirements through 2020," by issuing the RFP, Xcel is not "committing to add wind generation if no projects provide reasonable benefits over the long term."

Attachment D, MPUC Briefing Papers, p. 4, Xcel Energy IRP Docket E-002/RP-10-825; see also Attachment E, Wind RFP Update, p. 2, February 3, 2013. Transmission is not necessary for utilities to comply with Minnesota's RES – they are already in compliance.

4. Complainants have accurately portrayed "Tipping Point"

As above, the generation presumed in the Corridor study is the generation in the MISO queue, a selection of a percentage of it determined by Respondent Utilities. This generation is part of that MISO queue generation utilized in the CapX studies, where 16,712 MW was waiting in queue. See Attachment B, 2005 Technical Update, c.f. Corridor Study.

Respondent Utilities misrepresent the instability issue present with a radial line to La Crosse, and provided the Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study as an attachment to their Answer. See Answer of Respondent Utilities, Attachment H. This study does acknowledge the radial nature of the Hampton – La Crosse transmission project and that it does create stability issues, recognizing that a 345 kV radial line is "only a piece of a more comprehensive solution," and expressly states that if the radial line were built before the extension, it would require significant additional lower voltage system upgrades. The Hampton – Rochester – La Crosse line is planned to be built before any extension to connect into the 345 kV system, and the La Crosse line was approved by MISO in 2008 and the Minnesota Public Utilities Commission years before the La Crosse – Madison transmission line was included in the 2011 MTEP.

This study, published in March 13, 2006, includes Rochester and La Crosse load area studies, and was a foundational study used to support the CapX 2020 Certificate of Need application in Minnesota.[18] This study did raise the issue of the radial line to La Crosse, and included an analysis of the radial Hampton – La Crosse line:

> The radial analysis was performed to study the system impact of a radial 345 kV line in the region in the event that the longer regional 345 kV line options discussed above would not be constructed immediately.

Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study, p. 4, Respondent Utilities Appendix H.[19]

This study succinctly noted:

> The radial analysis showed that additional lower voltage system upgrade would be required for any of the options and extensive work would have to be done to modify existing operating guides and in some cases create new operating guides for operation of the system until the radial 345 kV line could be tied into the existing 345 kV system to the east (West Middleton or Columbia) or to the south at Salem. The radial option would, however, be much more economical than implementing the 161 kV local area solutions in the Rochester and La Crosse areas and then constructing a radial 345 kV line from Prairie Island to North La Crosse.

Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study, p. 5.

In the La Crosse load serving study, "Regional 345 Option Analysis" five transmission options were considered, and each began near the Twin Cities (Prairie Island) and connected into the 345 kV system, either at Columbia or West Middleton, or at Salem. No radial option was considered. Respondent Utilities' Answer, Attachment C, Corridor Study p. 78

> The key finding of the **RES Update Study** is the realization of an operational limit on the amount of wind penetration that can be accepted into the transmission grid in the **upper Midwest.** The RES Update Study verified that installing additional variable or intermittent generation sources (beyond what was assumed in the Corridor Study) would require the larger fossil fuel generators near the Twin Cities to begin backing down. It is also possible that these limits could be observed during very low load periods, requiring

[18] See CapX 2020 Certificate of Need Application, Appendix A-2, MPUC Docket ET02, E-002/CN-06-1115.
[19] This study was also included as Appendix A2 of the Minnesota CapX Phase I Certificate of Need Application, MPUC Docket ET02/CN06-1115.

> the curtailment of wind generation in order to maintain operable output of larger generators.

Id., p. 10 of 205 (emphasis added). Note that this both demonstrates a preference of maintaining operable output of larger fossil generators rather than causing them to be shut down, and also that this study's focus is generation for transmission throughout the Midwest, and not focused on Minnesota RES.

> An indicative stability assessment was also performed. This assessment confirmed that significant new reactive capability will be necessary as variable and intermittent generation sources increase. This is due in large part to generation being located a significant distance from load centers. At the same time, some larger generators are being turned down to make room for the new generators.

P. 14 of 205. This demonstrates that the purpose is to transmit power from generation to a distant load center beyond Minnesota.

The Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study identified Stability studies as "Additional Work to be Done." That did not occur prior to the CapX 2020 Minnesota Certificate of Need application and routing dockets. It also did not occur in the CVS Study which noted that a thorough technical evaluation of all transmission projects in combination has not been performed. CVS p. 11. The instability problems were demonstrated in the Respondent Utilities Corridor Study, Western Wisconsin Transmission Reliability Study, Capacity Validation Study and Supplemental Need Study. See e.g. Corridor Study; Western Wisconsin Transmission Reliability Study, Capacity Validation Study p. 50-51 (If Xcel Energy were to actually shut down as much generation in the Twin Cities as was simulated in the CV, it is expected that large amounts of reactive capacity would need to be installed in the Twin Cities area. As generation moves further away from load, more reactive support is needed at the load and on the transmission in between to support the system voltages… The results of the CVS indicate a line to the east is needed); and Supplemental Need Study.

IV. CONCLUSION

Citizens Energy Task Force and Save Our Unique Lands again request that the Federal Energy Regulatory Commission order that the MTEP 08 addition of the Hampton-Rochester-La Crosse transmission line is prohibited because electrical impacts of the addition of this project to the grid were not considered, and that instead of improving the reliability of the system, it contributes to and/or causes electrical system instability; that the Midwest Reliability Organization (MRO) has neglected its duty to preserve the reliability of the system; and that the Commission Order revocation of the Midwest Independent Transmission Service Operator (MISO) approval of the CapX 2020 Hampton-La Crosse transmission project because the addition of the Hampton-Rochester-La Crosse transmission line contributes to and/or causes system instability. CETF and SOUL request that the Commission order stability studies to determine the system impact of a fault on a radial Hampton – La Crosse line if it were constructed and energized without a connection to the 345 kV system.

Respectfully submitted,

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April 5, 2013

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Citizens Energy Task Force and
Save Our Unique Lands,

Complainants,

v. **Docket No. EL13-49-000**

Midwest Reliability Organization (MRO); Midwest Independent Transmission System Operator, Inc. (MISO); and utilities Xcel Energy, Inc. (Northern States Power Company, a Wisconsin Corporation, Northern States Power Company, a Minnesota Corporation, d/b/a Xcel Energy); Great River Energy, a Minnesota Cooperative Corporation; Dairyland Power Cooperative, a Wisconsin Cooperative Corporation; Wisconsin Public Power Inc., a Wisconsin corporation; as Applicants for the CapX 2020 Hampton-La Crosse Transmission Project.

CERTIFICATE OF SERVICE

Carol A. Overland certifies that on April 4, 2013, I hereby certify that a true and correct copy of the foregoing Motion for Leave to Answer and Answer was eFiled in FERC's electronic filing system and also served by electronic mail upon respondents and all commenters and intervenors, as required by FERC's Regulations.

Dated: April 5, 2013

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Attachment A

Comments of the Organization of MISO States
FERC Docket No. AD09-8-000
November 23, 2009

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Processes Under Order No. 890	))	Docket No. AD09-8-000

COMMENTS OF THE ORGANIZATION OF MISO STATES

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Request for Comments issued on October 8, 2009, the Organization of MISO States ("OMS") hereby submits the following comments regarding transmission planning processes and transmission cost allocation. The Commission originally requested that Comments be submitted no later than November 9, 2009, but subsequently extended that deadline to November 23, 2009.

I. DISCUSSION

The Commission seeks comments about how the current transmission planning processes and the transmission cost allocation practices can be improved. The OMS supports the Commission's initiative to examine the effectiveness of existing transmission planning processes and cost allocation practices, particularly focusing on their regional and inter-regional aspects. The OMS cautions, however, that in its efforts to facilitate transmission investment, the Commission should not abandon principles that have served the industry well for decades. Given the high stakes for the nation in effective energy policy, the Commission must ensure that the processes being developed for regional and inter-regional transmission planning and the practices for transmission cost allocation provide for the nation's future energy needs, while recognizing individual states' interests in ensuring the reliable service to retail customers at reasonable rates. Given the geographic expanse, abundant resource endowment, unique electrical topology and illogical seams and borders of the Midwest ISO region, the OMS has a particular interest and great stake in the Commission's examination of transmission planning and transmission cost allocation policies.

In particular, the OMS recommends that the Commission recognize and support the ongoing initiatives of state regulators, state policymakers, RTOs and stakeholders in particular parts of the country to address and resolve transmission planning, development and cost allocation in ways acceptable to the various needs and multiple interests in those parts of the country. The need for improved transmission planning and fair cost allocation will only increase if policies require the development and construction of additional renewable energy and no-carbon or low-carbon generation. New transmission will be necessary to support these policy choices, which may require that new renewable power be transmitted across long distances and multiple regions. In addition to improved transmission planning, fair transmission cost allocation will become even more important. If the ongoing regional and inter-regional grass-roots efforts to develop policy solutions are able to produce broad consensus, or at least a common understanding regarding solutions, such solutions would create a strong foundation of industry certainty that would likely have more permanence than federally imposed solutions.[1]

The OMS urges the Commission to act only in geographic areas and on issue areas where state and stakeholder action is absent or not working and Commission action may be necessary to stimulate progress. The Commission should allow the genuine state and regional-level efforts

[1] An example of an ongoing effort to develop such policy solutions is the OMS Cost Allocation and Regional Planning workgroup known as CARP. While CARP is further described below, mention of its work is warranted here. Since its inception in January of 2009, CARP has been working with the staff of the Midwest ISO to develop transmission plans that incorporate the viewpoints of OMS members. These efforts have also led to an investigation of a cost-allocation proposal that seeks to assign costs for transmission based on analyses of system usage, i.e., a cost allocation based on "injections" onto and "withdrawals" from the transmission system. CARP is positioned to begin making decisions relating to this proposal at its December meeting.

that have already been initiated to produce progress to proceed in those efforts. If, after a reasonable period of time without substantive results being produced by the existing cooperative efforts led by state policymakers, the Commission should consider issuing policy directives to address transmission planning and transmission cost allocation policies.

A. Transmission Planning Process

Historically, transmission planning and development focused on local reliability needs. However, the development of wholesale energy markets, the central dispatch of generation and the establishment of renewable energy portfolios have shifted this paradigm significantly. This requires transmission planners to perform reliability and economic analyses over much larger footprints. There is also the potential for Congress to enact climate change legislation that will also affect transmission planning and transmission system needs in significant ways. If climate legislation is enacted that restricts the emission of carbon dioxide, it is likely to have a transformational impact on the generation portfolio in many states over a very short period of time. Such new energy policy could result in the construction of new transmission lines to deliver significantly more energy from locations that are remote from load centers. Before the Commission proceeds to implement a large scale planning proposal of its own choosing, the Commission should be aware that states and regional state committees in some areas of the country have already begun the process of adapting to this new era of transmission planning. Indeed, the American Recovery and Reinvestment Act of 2009 ("ARRA") gives significant new impetus to creating a much larger and stronger collaborative approach among all stakeholders. These state and regional processes will lead to better transmission planning results than a federally-led process. These participants have an understanding of the local and regional concerns that are a key to the development of an effective transmission planning process.

At the state level, the OMS is aware of two significant efforts in the Midwest ISO footprint. First, the OMS has formed a Cost Allocation and Regional Planning ("CARP") initiative. In January 2009, this group began an initiative working with the Midwest ISO to consider new cost allocation methods. Part of this initiative includes the development of indicative regional transmission plans tied to particular sets of scenarios and to consider a cost-allocation methodology. Significant computer modeling of generation expansion and needed transmission infrastructure have been part of the CARP initiative. Results from this initiative may be ready as soon as early to mid 2010.

The second state policy-maker led approach involves the governors and state commissions from five states. Specifically, governors from Iowa, North and South Dakota, Minnesota and Wisconsin have formed the Upper Midwest Transmission Development Initiative ("UMTDI") with the goal of identifying necessary transmission infrastructure to deliver renewable energy from the western Midwest ISO footprint to states with renewable portfolio standard ("RPS") requirements. The UMTDI participants are also investigating the potential that the five states could develop transmission lines that would provide for the export of renewable energy beyond the borders of the states engaged in this effort. The UMTDI effort is expected to finish its work in 2010 and is also examining cost allocation issues.

The CARP and UMTDI initiatives show that state leadership is already taking action to adjust to new transmission planning needs, the realities of the ARRA funding impacts and the possibility of new federal energy policy.

The most recent development in regional transmission planning is the largest in scope, comprising the entire Eastern Interconnection. The ARRA directed $80 million to the Department of Energy ("DOE") to conduct resource assessments and provide technical assistance for interconnection-wide planning. The DOE released a Funding Opportunity Announcement ("FOA") in June of 2009 that identified distinct roles for transmission planners and engineers (Topic A) as well as a specified role for state policymakers and regulators (Topic B).[2]

After the release of the FOA, representatives from Governors' offices, state energy offices, regulatory commissions and other leaders throughout the eastern United States proposed to the DOE on September 14, 2009 under Topic B that an Eastern Interconnection States' Planning Council ("EISPC") be established. One of EISPC's major goals is to have state policymakers within the Eastern Interconnection create and establish a coordinated and consistent set of directives and analyses (e.g., assumptions and scenarios) for the modeling that will take place with this funding by the DOE-selected Topic-A entity. Of the 41 jurisdictions in the Eastern Interconnection, 38 have filed letters of support for the proposal. This represents an impressive and unprecedented level of cooperation among the states in the Eastern Interconnection.

EISPC, CARP and the UMTDI are prime examples of the role that state leadership can play in transmission planning and the development of new transmission infrastructure. There are a variety of reasons why these state and regional processes are likely to produce better results than a federally-led process. First, state commissions have the ultimate responsibility for retail electric rates and are therefore keenly aware of how the costs of interstate transmission lines will flow to ratepayers. Second, transmission planning must accommodate state choices with respect to generation portfolios and the complementary demand-side programs. Third, state regulators are better situated to identify and address transmission upgrades such that they do not harm or require excessive upgrades to existing facilities. Lastly, because state agencies are closer to

[2] U.S. Department of Energy Funding Opportunity Announcement DE-FOA-0000068

those regulated, their decisions will be more legitimate to those affected most by new transmission lines. State-level decision-making allows for more complete public information, participation, credibility and public acceptance.

The OMS encourages the Commission to support CARP, UMTDI, EISPC and other similar initiatives that may follow these models. The OMS also recommends that the Commission facilitate the development of additional such state-led transmission planning and cost allocation stakeholder efforts by framing and clarifying the range of available policy options, particularly with respect to inter-regional issues.

- **Are existing transmission planning processes adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers? Should prospective transmission developers coordinate their projects in the interest of "right-sizing" facilities to make the best possible use of available corridors and minimize environmental impacts? If so, what process should govern the identification and selection of projects that affect multiple systems?**

The Midwest ISO's intra-RTO transmission planning process is generally working well and the above-mentioned interconnection-wide transmission planning efforts are too new to judge. While some of the inter-regional issues may ultimately be addressed by larger planning efforts like EISPC, the inter-regional transmission planning processes need to be improved and merit Commission guidance. The OMS offers recommendations in this regard below.

In general, RTO planning efforts focus on identifying the needs of the customers within the RTO and issuing a transmission expansion plan that identifies and evaluates options and proposes a solution to meet those intra-RTO needs. While some RTOs, including the Midwest ISO, participate in inter-RTO planning, those activities are often separate from the RTO's internal planning efforts. Internal RTO planning efforts are generally aimed at developing a transmission expansion plan with projects that the RTO directs to be built. As such, inter-RTO planning efforts are largely an academic exercise, with no apparent coordination among the various regions.

Sound transmission planning should provide an orderly structure to coordinate transmission projects not only to "right size" facilities but to make the best use of transmission corridors and not unduly create more corridors or new constraints. To the extent transmission developers are able to work cooperatively together, project costs may be shared among them which should reduce each developer's project costs, thus benefitting the developers' customers.

Ideally, the purpose of any proposed project would be clearly stated and transparent. Potential developers would, on their own, collaborate on selecting and locating potential joint projects and introducing the joint project into their ISO/RTO planning process. However, when collaboration fails, then the ISO/RTO planning process should identify project or project-portion alternatives that could reduce overall costs, "right size" facilities to meet identified needs over a larger footprint or more efficiently use transmission corridors. The states where the projects would be located should, in certain cases, have this information to conduct their state regulatory processes, and any developers opposing the more efficient alternatives would need to explain why such efficiencies should not be approved.

In addition, in the case of large inter-regional projects, it should be recognized that State Regulators may not be able to justify such large projects based solely on the benefits for their own states. In these cases regional cooperation will be critical to ensure that all transmission upgrades are "right sized" for current needs, as well as the foreseeable future. The identification and adoption of fair cost allocation or cost recovery methodologies will be an important piece of this necessary regional and inter-regional cooperation.

While the RTOs, particularly the Midwest ISO, have undertaken cross-border transmission planning, very little in the way of practical projects has, to date, come from it. As such, improvements should be made regarding coordination and goals of such endeavors.

- **Are there adequate opportunities for stakeholders to participate in planning activities that span different regions, including for example those undertaken pursuant to bilateral agreements?**

There is adequate opportunity for stakeholders to participate in planning activities. Indeed, there are numerous stakeholder forums at PJM and the Midwest ISO associated with transmission planning. However, the reality is that the practical ability of many stakeholders, including retail customers and those representing the interests of retail customers is limited. Transmission planning and energy industry practices generally are evolving rapidly. The Commission must understand that stakeholder resources, particularly those within state commissions and other customer and public interest representatives, are spread thin. To the extent that the Commission can identify policies that will streamline and focus state and regional efforts, the scarce resources of the state commissions and the stakeholders can be more effectively focused.

While there is some transmission planning coordination between the Midwest ISO and PJM, the effort is largely an add-on to existing intra-RTO practices rather than being a combined transmission planning process. What is missing from the current inter-regional planning continuum is a coordinated process that involves the stakeholders of all affected RTO regions and a focus on issues impacting the regional and inter-regional RTO footprints. Furthermore, inter-regional involvement by stakeholders is very challenging, in that stakeholders would have to be involved in multiple ISO/RTO processes simultaneously. In particular, state commissions that straddle the PJM/Midwest ISO seam struggle to meaningfully participate in the transmission planning efforts of both the Midwest ISO, PJM and SPP. Similarly, state commissions not close to RTO seams do not have the resources to participate in inter-seam planning, even though such actions would impact these states as well.

In sum, the inter-RTO transmission planning processes merit additional Commission guidance and the OMS makes recommendations below in this regard.

- **Is there adequate coordination among planning entities to provide consistency in the data, assumptions and models being used in planning activities?**

The OMS is not in a position to directly answer this question. The planning entities are in the best position to respond about consistency between the planning entities. However, it is clear that PJM and the Midwest ISO can be subject to some modeling inconsistencies such as those illustrated by the recent market flow calculation controversy in Docket No. ND10-1-000. Part of this settlement proceeding may include an investigation of whether the calculation errors impacted loop flow assumptions, day-ahead unit commitment and/or Financial Transmission Rights /Auction Revenue Rights auction results. While that matter involves market operations and settlements rather than planning issues, it illustrates the potential negative effect that even small data inconsistencies can have on modeling efforts.

Planning for large RTO regions is a very complex process that involves many assumptions about any number of planning scenarios. There may not be a one-size-fits-all approach to modeling the interconnected grid. However, more formal coordination of individual system expansion plans between individual regions and planning entities will likely lead to more effective and efficient transmission planning. Due to the complexity of the grid, coordination needs to focus on inter-regional projects and high voltage bulk power transmission planning. Further, data availability and consistency is almost certain to be an issue as larger planning processes like EISPC move forward. To the extent the Commission can help facilitate the sharing and accumulation of data for this endeavor, it will increase the efficiency and the likelihood of success of the inter-regional coordination efforts.

- **Will the interconnection-wide processes adopted pursuant to funding opportunities under the American Recovery and Reinvestment Act of 2009 result in an ongoing process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing sub-regional and regional planning processes? Will the scope and function of these interconnection-wide planning activities be sufficient to help address the concerns identified above? How will planning activities conducted on an interconnection-wide basis be integrated into the development of sub-regional and regional transmission plans and vice versa?**

One of the ARRA's goals is to improve the coordination and development of transmission planning and infrastructure construction utilizing input from all stakeholders, the RTOs, the utilities, the states and others.[3] With respect to interconnection-wide planning, this legislation should be given its chance before the Commission steps in with alternative interconnection-wide policies. Once established, this baseline will allow appropriate entities to develop their business case for appropriate projects, and states with siting authority will have a foundation of sound planning and stakeholder input to begin their respective review processes.

While it is still too early to definitively say whether the interconnection-wide transmission planning process will succeed, the OMS believes that participants will work in good faith to provide interconnection-wide plans for the benefit of the entire Eastern Interconnection. We also believe that the ISO/RTO entities in the regions will attempt to incorporate the interconnection-wide plans into their regional planning processes and filter such regional plans down to the sub-regional levels. As such, it is too early for the Commission to impose change on those efforts. While there may be a place for Commission-initiated policy improvements with respect to both regional and inter-regional transmission planning in some parts of the country,

[3] U.S. Department of Energy Funding Opportunity Announcement DE-FOA-0000068, at 5

interconnection-wide transmission planning efforts are in their nascent stages and should be given time to produce the expected results. As interconnection-wide transmission planning proceeds over the next few years, situations may arise that call for the Commission to nudge it in one way or the other, but doing that now would be disruptive rather than helpful.

- **How are reliability impact studies aligned with economic-based evaluations of sub-regional or regional projects and assessments of projects needed to satisfy renewable energy standards? If not aligned, how can reliability assessments and economic evaluations be aligned in order to better identify options that meet regional needs?**

Presently, in the Midwest ISO footprint there is a distinction with respect to eligibility for cost sharing and cost allocation between network upgrades, reliability projects and economic or commerce-oriented transmission facilities. At the time these cost allocation distinctions were adopted, they made sense because transmission planning and development was a function of reliability and economics. However, such distinctions fail to fully capture the dynamic nature of the transmission grid. For example, from electrical engineering and economic perspectives, a transmission line that fulfills these goals today may have less of an impact on these objectives in the future.

The OMS is not aware that the distinctions between reliability planning, generator interconnection planning, economic planning and renewable resource planning create any problems focusing strictly on the RTO's engineering planning and not cost allocation. The difficulty lies in defining into which single category of "need" particular projects with multiple uses and benefits must be slotted. Such single-purpose designations do not further efforts to meet some of these particular planning purposes and fairly allocating the costs of the projects that are determined to be needed.

The Midwest ISO also includes reliability testing as well as economic evaluations in its current sub-regional and regional planning processes. For example, the Midwest ISO's Regional Generation Outlet Study (RGOS) is intended to identify which states have renewable portfolio standards, how much renewable energy is needed in each state, potentially where the renewable energy would come from and the transmission needed to deliver that energy. However, at the present time, the Midwest ISO's tariff is not aligned with its planning efforts. Although the Midwest ISO and stakeholders are working diligently to derive a new rate tariff structure that does reflect today's drivers for transmission planning and construction, this tariff-planning misalignment is causing significant issues for proposed projects.

- **How should merchant and independent transmission projects be treated for purposes of regional transmission planning?**

All proposed transmission projects, including independent transmission projects, should be treated the same in regards to regional transmission planning. In short, all transmission proposals should be subject to the planning and study processes that are in place to ensure that the interconnection and operation of the proposed project will not detrimentally impact the grid. After all, there is only one interconnected transmission system in the eastern interconnection (even DC lines need to interconnect with AC lines at the ends of the lines.) As such, all new proposals should have to go through the RTO planning processes in place to ensure the continuing integrity of the grid. No project should be approved by the FERC before these processes are completed or any approvals should be conditioned on successful, timely completion of these processes.

- **Should they be required to participate in the planning process and, if so, at what point must they engage in the planning process?**

All transmission proposals need to be subject to the RTO planning and testing processes to ensure that the project can safely and reliably be interconnected and operate within the grid. Exceptions would not be in the public interest.

- **Do rights of first refusal for incumbent transmission owners unreasonably impede the development of merchant and independent transmission? If so, how can this impediment be addressed?**

Please see the answer to the next question.

- **Are there other barriers to the development of merchant and independent transmission in the transmission planning process?**

The Commission must ensure that, with respect to RTO transmission planning, there is no undue preference for incumbent or non-incumbent transmission providers or their affiliates. In particular, any rights of first refusal in RTO transmission planning practices could have a negative influence on the development of transmission lines if an incumbent uses the right of first refusal to impede the development of transmission identified as approved in the RTO's planning processes. While any right of first refusal should not be permitted to unduly discriminate against merchant and independent transmission, allowance must also be made for differences in state regulatory structures.[4]

The Midwest ISO Transmission Owners' Agreement ("TOA") establishes the Midwest ISO as the regional planning authority. The TOA states, "The Midwest ISO shall engage in such planning activities as are necessary to fulfill its obligations under this Agreement and the

[4] For instance, in a traditionally regulated state, such as Indiana, utilities are generally vertically integrated with monopoly status within its service territory; i.e., no other utility may operate within the service territory of another utility without regulatory approval.

Transmission Tariff."[5] The TOA requires the Midwest ISO to produce a Midwest ISO Plan on a biennial basis.[6] The TOA provides that, "Approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities."[7] The TOA then requires that, "The affected Owner(s) shall make a good faith effort to design, certify, and build the designated facilities to fulfill the approved Midwest ISO Plan."[8] The TOA states that, "Each Owner shall use due diligence to construct transmission facilities as directed by the Midwest ISO [ ] subject to such siting, permitting, and environmental constraints as may be imposed by state, local, and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals."[9]

While it is not specifically identified as a "right of first refusal," the TOA includes the following language:

> Ownership and the responsibility to construct facilities which are connected to a single Owner's system belong to that Owner, and that Owner is responsible for maintaining such facilities. Ownership and the responsibilities to construct facilities which are connected between two (2) or more Owners' facilities belong equally to each Owner, unless such Owners otherwise agree, and the responsibility for maintaining such facilities belongs to the Owners of the facilities unless otherwise agreed by such Owners. Finally, ownership and the responsibility to construct facilities which are connected between an Owner(s)' system and a system or systems that are not part of the Midwest ISO belong to such Owner(s) unless the Owner(s) and the non-Midwest ISO party or parties otherwise agree; however, the responsibility to maintain the facilities remains with the Owner(s) unless otherwise agreed.[10]
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> …,

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[5] Agreement of the Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("TOA") Article Three, Section I, Para. C.
[6] TOA Appendix B, Article VI
[7] TOA Appendix B, Article VI
[8] TOA Appendix B, Article VI
[9] TOA Article Four, Section 1, Para. C.
[10] TOA Appendix B, Article VI

> If the designated Owner is financially incapable of carrying out its construction responsibilities or would suffer demonstrable financial harm from such construction, alternate construction arrangements shall be identified. Depending on the specific circumstances, such alternate arrangements shall include solicitation of other Owners or others to take on financial and/or construction responsibilities. Third-parties shall be permitted and are encouraged to participate in the financing, construction and ownership of new transmission facilities as specified in the Midwest ISO Plan. In the event interest among other Owners or other entities is not sufficient to proceed, all Owners, subject to applicable regulatory requirements, shall be responsible for sharing in the financing of the project and/or hiring of a contractor(s) to construct the needed transmission facility; provided, however, the Owners' obligations under this sentence shall be subject to the Owners being satisfied that they will be compensated fully for their investments and will not be subject to additional regulatory requirements, unless the Owners otherwise agree to waive either or both of these requirements.[11]

These provisions of the TOA, particularly the provision that provides existing transmission owners with the responsibility to construct facilities that are connected to the owner's system and the ownership rights to such facilities may be interpreted as a "right of first refusal". If interpreted in that manner, these provisions could act as a discriminatory barrier to independent and merchant transmission developers, since a developer that is not a designated "Owner" would only be able to construct in the Midwest ISO footprint when a designated "Owner" was financially incapable of doing so or otherwise declined to do so. While "third-parties" are permitted to participate in the financing, construction and ownership of new transmission facilities, such opportunity appears to arise only after the incumbent transmission owners have declined the opportunity. This right of first refusal may preclude the ability of independent transmission owners from competing with incumbents to build projects. Placing all transmission developers on equal footing could bring discipline to transmission costs through increased competition between developers. However, any changes to these provisions of the TOA would still need to recognize different state regulatory structures and not impede on state jurisdiction and statutes.

[11] TOA Appendix B, Article VI

The question of whether merchant and independent transmission projects are eligible for funding from RTO customers is an open one in the Midwest ISO in the area of transmission constructed for the interconnection of remote renewable energy sources. A merchant transmission developer could employ self-funding for its project. On its face, it would seem that a self-funded merchant transmission proposal would only need to satisfy the operational planning aspects of the RTO, since the developer would not be asking the RTO customers to fund the project. How such a project would or could be usurped by an existing transmission owner using a right of first refusal, with consequent funding from the RTO customers, is one of the questions that will need to be addressed during the MISO RECB stakeholder process. Two other issues also need to be discussed. One is how the recovery tariff will be set for one Transmission Owner whose AC line crosses five other Pricing Zones, or TO owners. Another issue to be discussed is who is responsible for funding and/or owning the underlying system upgrades that support the Extra High Voltage overlay.

In sum, the Commission must ensure that independent and merchant transmission developers can meaningfully participate in the RTO transmission planning process and that RTO practices do not unduly discriminate against any transmission owner with respect to transmission project development and ownership. Any provisions of RTO/ISO tariffs or agreements that frustrate this participation should be scrutinized and clarified, while still giving consideration and allowance for state regulatory structures.

- **Should similar assumptions regarding resource availability be used for generation owned by the transmission owner and merchant or independent developers?**

All generation, regardless of whether it is affiliated with a transmission owner must be treated the same with respect to transmission planning.

- **Is the interconnection queue process hindering the ability to plan the transmission system to integrate new generation? Would any reforms to the Commission's interconnection procedures support efficient planning of the transmission system?**

Any interconnection queue system could possibly hinder the ability to perform meaningful planning if it is not designed correctly. For example, a highly permissive queue system (i.e., one with few requirements for getting and staying in the queue) may not have sufficient controls to discourage or prevent game playing and will likely be overwhelmed with projects, many of which have a very low likelihood of actually being built. This system will send an unclear signal to transmission planners that are attempting to incorporate likely generation development into future development scenarios. Conversely, a queue process that is too restrictive may impede the identification and development of necessary generation and may unduly restrict the types of entities engaging in such development. Where the balance lies between these competing positions is difficult to determine, and may be very different from region to region, where different policies and resources may take precedent. However, striking such a balance is worth the attention in order to facilitate planning efforts.

The Midwest ISO's interconnection queue process itself generally does not hinder transmission planning. However, there are a large percentage of the projects currently in the queue that will never be built. The fact that many of these interconnection decisions are in the hands of parties proposing new generation rather than the Midwest ISO and its member transmission owners, could be seen as too permissive and makes efficient transmission planning difficult. Conversely, parties are starting to see that interconnection queue rules may discourage or prevent settlements between generators and transmission owners for the purposes of facilitating interconnection agreements. The Midwest ISO has been working with a variety of stakeholders in an attempt to find the proper balance for its interconnection queue.

Determining and implementing an interconnection queue process that is "just right" is clearly a difficult but important element to the implementation of a successful transmission planning effort. The Midwest ISO's effort to address its interconnection queue problems should be given a chance to succeed. To that end, the Commission should follow the Midwest ISO's interconnection queue reform processes and give them a chance to succeed as well as coordinate with current planning efforts by CARP, UMTDI and MISO stakeholders before the Commission seeks to develop or impose any policies concerning the Midwest ISO's interconnection queue.

- **Should there be consistency in the way transmission providers treat demand resources, such as demand response, energy efficiency and distributed storage, in the transmission planning process? Are there preferred methods of modeling or otherwise accounting for demand resources in the planning process? Does the planning process investigate transmission needs at fine enough granularity to identify beneficial demand resource projects?**

The importance of demand response, energy efficiency, distributed storage, distributed resources and price responsive demand is rapidly increasing and these elements will likely have even greater impact in the future. Effective transmission planning must take these elements into account. Granular transmission planning that is able to account for these resources and elements as well as the regional and regulatory differences that may apply to them will be a positive development. The measurement and verification of these types of resources is an issue that will need to be addressed.

- **Are existing dispute resolution procedures in transmission provider tariffs adequate to address disputes that arise in the planning process?**

The Midwest ISO tariff provides effective alternative dispute resolution ("ADR") procedures available for disputes that arise in the planning process. These procedures have been called on sparingly and far more often with respect to market and settlement issues than planning issues. The OMS is not able to advise whether the ADR procedures are infrequently used because Midwest ISO market participants are not familiar with using these procedures or because the Midwest ISO has been successful in resolving most disputes at an early stage. It is the OMS' understanding that the Midwest ISO is considering modifications of the ADR procedures to improve stakeholder awareness of their availability, to make submission of a dispute easier, and to improve the fairness of the procedures.

B. Transmission Cost Allocation

The OMS recognizes that lining up the causes and beneficiaries of a single line is often difficult (particularly in an alternating current grid), and that the benefits of any single line are likely to change over time. The CARP work group, the RECB Taskforce as well as the UMTDI are investigating different approaches.

- **To the extent that a lack of up-front certainty about cost allocation is inhibiting transmission development, describe the relative impact of this concern on specific projects and as it relates to other impediments to development.**

State regulators have been told that the lack of up-front certainty about a cost allocation methodology is one of the greatest inhibitors to transmission development. Therefore state regulators and other policymakers are working together and are making a concerted effort to provide leadership to develop a workable and fair cost allocation methodology that will remove any barrier that the current methodology may create. CARP, RECB and UMTDI have cost allocation discussions as their main focus. The cost allocation methodologies that these processes work to develop will be evident in the near future.

- **Should processes be established to help stakeholders address cost allocation matters over larger geographic regions? What is an appropriate scope for those regions? Should they align with the regions for which planning is conducted?**

Transmission costs should be allocated over the same geographic areas that are affected by the energy transactions. Since inter-regional energy transactions are common and the effects of those transactions are often broad, then costs should be allocated commensurate with the beneficial effects of the transaction. The main issue lies in how beneficiary and cost causers are defined, which is precisely the question that CARP, RECB and the other regional processes described above are attempting to define in their cost allocation discussions.

Inter-RTO cost allocations may be a more difficult issue. In the case of PJM and the Midwest ISO, scenarios arise where the cost causers/beneficiaries are located in one or both RTOs. However, since the current Midwest ISO/PJM inter-regional tariff is discounted to zero, there is no opportunity to charge the load or generators in the other RTO for the benefits of new transmission projects that are received. As such, with the prospect of billions of dollars of new transmission projects in an RTO with significant renewable energy resources, customers in one RTO will be unfairly subsidizing transactions in the other. The Commission should direct the RTOs to create an inter-regional tariff that charges the beneficiaries of the transmission system, regardless of which RTO they are located in.

- **Are there regional cost allocation methodologies outside RTOs, and broader regional cost allocation within RTOs, that should be considered or established? If so, how should this be done?**

In Order 890, the Commission did not require any specific cost allocation method, but provided the following overall guidance:

> First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation

> proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by state authorities and participants across the region.[12]

Much has changed since the issuance of Order 890 and the Commission should now refine and clarify its guidance, particularly with inter-regional (e.g., inter-RTO) impacts in mind.

First, the Commission should reexamine and reiterate its desire to have cost causers and beneficiaries pay for the transmission upgrades that are necessary to fulfill a variety of goals. One way to assign new transmission costs is to base assignments on an assessment of those market participants that cause the costs to be incurred and those market participants that benefit or will benefit from the new transmission.[13] However, lining up the cost causers and beneficiaries of a single line is often difficult (particularly in an alternating current grid), and the benefits of any single line are likely to change over time. At the same time, as the 7th Circuit Court found, in order to be counted in the quantification, the purported benefits must be "articulable and plausible."[14] To that end, because the costs of new transmission are quantitative, the assessment of causation and beneficiaries should also be quantitative, if possible. While there are numerous just and reasonable ways to measure benefits and beneficiaries, the assessment should, to the extent possible, be a quantitative and demonstrable evaluation of incremental transmission facility impacts rather than just a qualitative assessment based on generalized assumptions or unsupported speculation. Indeed, quantified information should typically be weighted more heavily than non-quantified information. However, non-

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[12] *Preventing Undue Discrimination and Preference in Transmission Service* 118 FERC ¶ 61,119, (2007) at P 559 ("Order 890")

[13] See *Illinois Commerce Commission, et al., v. Federal Energy Regulatory Commission, et al.,* ("7th Circuit Decision) at p. 10, where the Federal Court of Appeals for the 7th Circuit Court stated that, "To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."

[14] 7th Circuit Decision, at p. 11, where the 7th Circuit Court allowed that, if purported benefits cannot be quantified, they must at least be "articulable" and have a "plausible reason."

quantifiable costs and benefits definitely exist and need to be assessed and addressed. After the quantifiable factual and policy information is presented and vetted, non-quantifiable costs or benefits should be recognized and factored into the support or opposition to a case.

Second, the Commission has not heretofore given sufficient weight and sufficient clarity to its third guiding factor from Order 890. The Commission stated that it will "consider whether the [cost allocation] proposal is generally supported by state authorities and participants across the region."[15] However, the Commission has not yet clarified how it will judge whether there is general support by state authorities and participants across the region. Nor has the Commission established what the "region" is. The Commission has not yet clarified what weight it will give to general support by state authorities and participants across the region when it is evaluating a transmission cost allocation proposal.

With respect to transmission planning and cost allocation, the state commissions in the Midwest are primarily concerned with the following "regions": (1) the Midwest ISO region; (2) the PJM region; (3) the combined PJM and Midwest ISO region; (4) the combined Midwest ISO and SPP region; and (5) the combined Midwest ISO and non-Midwest ISO MAPP region.

With respect to the Midwest ISO region, the OMS formed the CARP working group to try to forge consensus (or at least a common understanding of differences in view) among the Midwest state regulators and policymakers on difficult transmission planning and transmission cost allocation issues. The Midwest ISO stakeholders have a Planning Advisory Committee ("PAC") and a Regional Expansion Criteria and Benefits ("RECB") task force to develop proposals and provide advice to the Midwest ISO on transmission planning and transmission cost allocation issues. The OMS CARP and the Midwest ISO RECB are working together in an

[15] Order 890, at P 559

iterative manner on transmission cost allocation policy. The CARP and RECB processes are inclusive, transparent, and comprehensive.

The OMS recommends that such arrangements serve as the model for cooperative and collaborative processes for transmission planning and transmission cost allocation. The Commission should declare that when cost allocation proposals (1) have been developed through such a cooperative and collaborative process and are generally supported by state authorities and participants; and (2) satisfy the cost causation - beneficiaries pay principle, the products and decisions produced by such process will receive great deference when submitted to the Commission for approval.

The OMS recommends that the Commission encourage the initiation of processes comparable to the CARP/PAC/RECB process for each of the other "regions" of interest to the Midwest state commissions, namely the (1) the PJM region; (2) the combined PJM and Midwest ISO region; (3) the combined Midwest ISO and SPP region; and (4) the combined Midwest ISO and non-Midwest ISO MAPP region.

As Steve Gaw pointed out in his September 10, 2009 Comments to the Commission in this proceeding, current RTO transmission planning does not deal well with the benefits of transmission projects to the extent those benefits flow to someone outside the RTO or outside the RTO's ability to bill for costs.[16] In some cases, benefits that accrue outside of the RTO responsible for the transmission planning are simply ignored. In which case, beneficial projects are not built because the aggregate of the benefits that are counted does not equal or exceed the cost of the project. In other cases, the benefits that flow outside the RTO are counted and the electric consumers inside the RTO are expected to pay for the costs of the project that generates

[16] Prepared Opening Remarks of Steve Gaw, Policy Director of the Wind Coalition, from September 10, 2009 Conference in Atlanta, GA under AD09-8

benefits to others merely because the RTO has no way of billing those others outside the RTO for the costs. Under such circumstances, projects will likely not be built because the intra-RTO customers expected to pay will balk with protestations that the benefits they receive do not equal or exceed the costs they must pay. In either case, the needs of the larger inter-RTO region are not well served.

Ideally, the geographic coverage of transmission planning processes would be coterminous with the flow of benefits from the transmission projects examined in such planning process. So, whenever intra-RTO planning finds projects for which benefits flow outside the RTO, a joint planning process with that transmission planning entity and its state policymakers and stakeholders must be initiated. In most cases, the flow of benefits from any particular project will be largely confined to the RTO's immediate neighbor. For this reason, the OMS recommends the establishment of standing joint planning processes with each of the Midwest ISO's neighboring transmission planning entities. However, in other cases, the benefits of a particular project may flow to even larger geographic regions, and, potentially, to the entire Eastern Interconnection. Therefore, the EISPC process may fulfill this needed element of transmission planning. The OMS is confident the Commission will be following the EISPC process to ensure that these broad geographic issues are sufficiently addressed in that process.

In the context of inter-RTO, and broader, transmission planning processes, the Commission should consider adopting rules or guidelines for inter-RTO transmission cost allocation. The guidelines must allow the RTO in whose footprint the transmission project will be built to assess costs, bill and collect from, the appropriate entities outside the RTO for costs of the project consistent with their benefits.

The state regulators are in the best position to judge the RTOs' beneficiary analyses. To the extent that a state's electric consumers will truly obtain benefits in accordance with the RTO's analysis, it can be expected that the state regulator will allow the recovery of the costs, provided that the costs are prudent and do not exceed the benefits that a project provides. Because, as explained above, if transmission costs are not reasonably allocated proportionate to benefits, it is likely that valuable transmission projects will not get built.

The Commission and the RTOs must work with the state commissions to establish how benefits of transmission projects will be measured and how the distribution of those benefits will be assessed.[17] The Commission and the RTOs must enable the state commissions to conduct their own independent analyses of benefits and beneficiaries. Unless sufficient data, information, analytical tools and capability to operate the analytical tools are provided to the state regulators, state regulators and the electric consumers they represent may balk at the prospect of incurring the costs of transmission projects.

- **Should each transmission provider hold an open season solicitation of interest for needed transmission projects identified through the transmission planning process in order to assist in cost allocation determinations?**

While an open season is unusual for electric operations, holding open season solicitations for proposed transmission projects has the potential to provide several benefits. In particular, an open season would likely provide information concerning the degree of interest in constructing the line and would assist in deciding questions regarding the size, type and timing of the project to best meet the requirements of the system. In instances where cost allocation uncertainty exists, holding open season solicitations could provide beneficial information regarding how

[17] The Commission stated in Order 890, "The states, which have primary transmission siting authority, may be reluctant to site regional transmission projects if they believe the costs are not being allocated fairly." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), 118 FERC 61,119, at P 560 (2007)

many interconnecting projects are interested and how much energy these parties expect to transmit over the proposed transmission lines. The open season concept may also help to ensure that new generation and transmission projects are built in tandem, and thus guard against the potential for stranded or underutilized assets.

However, open season solicitations may be helpful in certain states or regions, but may conflict in others because different transmission owner business models are utilized. Therefore, any policies relating to open season solicitations should be mindful of any interconnection requirements or other similar efforts will have to be sufficiently flexible to account for these state and regional differences.

A similar concept to open season is a competitive bidding process for the construction of new transmission projects. If the Commission were to pursue this concept, the OMS would expect that all qualified developers would be permitted to compete to build the transmission projects that are determined to be necessary under the relevant regional or inter-regional transmission planning process. In most cases, the winners of the bidding process would have to qualify as a public utility under applicable state law. A competitive process should produce the most cost-effective option for constructing a needed expansion of the transmission grid. A workable competitive process should be based on established criteria and standards for determining the most cost-effective bid such as:

(1) *Optimizing* (not maximizing) renewable integration;
(2) Ability to obtain timely permits and other authorizations;
(3) Capability to obtain timely financing; and
(4) Other relevant economic factors.

While existing transmission owners may be in a good position to establish these criteria, independent developers will likely be able to exert some competitive pressure on the transmission owners. The state commissions, as facilitators of the regional or inter-regional planning and cost allocation process would be in a good position to decide which entity/entities could most cost-effectively construct and own the transmission project.

- **How can the customers that benefit from a particular facility be determined? Is there a preferred method? Should the method vary depending on the nature of the facility?**

It is difficult to determine the particular customers that benefit from a specific transmission facility. There does not seem to be a widely accepted, preferred method that is applied in the United States. The OMS CARP group has been examining various methods this year. In particular, the CARP group has been exploring the injection/withdrawal cost allocation methodology. One aspect of a flow-based, injection/withdrawal cost allocation method is that the determination of beneficiaries is dynamic. The underpinning of this methodology is to model the generalized access and use of the current network. The results of this model then guide the allocation of costs of future transmission facilities. The OMS CARP group expects to complete its evaluation of the injection/withdrawal approach by the end of 2009.

- **Should costs for base upgrades needed for existing reliability or economics be allocated differently than excess capacity expected to be needed for later developed resources? Should the allocation of costs for certain projects take into account the risk of under-subscribed "right sized" lines? If so, how should costs be re-allocated over time as such lines become subscribed by new customers?**

In a world where there is a significant need for new transmission, the distinction between base reliability and market-based projects is at a minimum blurred and in reality, no longer needed. Defining "right sized" as posed in the question is challenging. Because of the overall need for further transmission, which is expected to continue to grow into the future, it makes some sense to purposely right size facilities to avoid having to "tear down and rebuild" in the near future or to have to come back in the and create additional transmission corridors to serve that next increment of future customer growth.

However, the "right sizing" concept may pose challenges to regulators and policymakers. Whether to support and how to address deliberately over-sizing (assumed to equate to "right-sizing") proposed transmission projects is a thorny issue that speaks directly to state and federal policies and laws. For example, as discussed above, over-sizing a project proposal can put state regulators and policymakers in a difficult position because most state law (and federal law) have various "public interest" and "used and useful" laws that typically discourage purposely constructing transmission capacity that will not be used when the line is put into service but is expected to be used in years to come. Such "right-sizing" of facilities is especially challenging for state regulators when the transmission project is over-built to serve projected needs in a different state. All of this is not to say that policies and laws may not start to be re-shaped to accommodate this change in thinking but it will not be done overnight.

- **Should cost allocation mechanisms continue to differ based on whether a project is deemed necessary based on reliability and adherence to approved reliability standards versus economic considerations?**

Reliability and economic considerations are both important reasons for transmission development, but this question fails to capture a significant reason why transmission development is necessary today. The fact is, most transmission development today is being discussed in order to fulfill policy considerations of encouraging and requiring additional renewable energy generation. Future development is likely going to be based on policy requirements to mitigate and reduce carbon dioxide emissions. While any development of new transmission will likely result in reliability and economic benefits, the cost allocation or cost recovery mechanisms may have to be focused on the policy reasons for the development.

Over time, any project will lower the risks of interruptions by some degree, and almost every upgrade justified for reliability concerns will inevitably yield at least some economic benefit. Given that both economic and reliability projects create costs and benefits on the integrated transmission system, transmission projects should be considered as a whole. Failing to acknowledge this new reality will allow some transmission projects to be constructed because they provide what are perceived to be "reliability benefits" while other "economic projects" are rejected for insufficient benefits despite allowing access to regions with lower cost generation resources. Such an outcome effectively imparts an artificial dividing line between projects that both contain an economic and reliability component. Furthermore, by reflexively approving every proposed reliability project, the Commission would potentially be ignoring more cost-effective solutions to serving incremental load such as targeted demand response or distributed generation.

- **How should non-quantifiable costs or benefits be identified, factored in or otherwise weighted?**

As noted above, the Commission must be sure to address the non-quantifiable costs and benefits, which, while difficult to fit into a numeric equation, definitely exist. Indeed, non-quantified information should be factored in with quantified information. After the quantifiable factual and policy information is presented and vetted, non-quantifiable costs or benefits should be recognized and factored into the support or opposition to a case.

- **Should the determination of beneficiaries of a transmission facility include generators as well as loads?**

Both generators and load benefit from the construction and operation of interconnecting transmission. In fact, it is difficult to imagine that an RTO could develop a workable or comprehensive set of benefits metrics that did not take into account the positive benefits obtained by generators (either existing or new) from new transmission projects. While it is basically true that, in the end, load pays for all transmission costs, allocating costs to generators proportionate to their benefits will better target the "correct" set of load as the generators attempt to recover their costs from their customers.[18]

- **Should benefits be recalculated over time? Would recalculations negatively affect usage decisions?**

The distribution of beneficiaries should be re-examined from time-to-time. As the electric system and its uses change over time, the beneficiaries of transmission projects are also likely to change over time. Re-examination of beneficiaries would also help to eliminate free riders on the transmission system.

Adjustments to a project's cost allocation to reflect changes in the beneficiary distribution over time need not create uncertainty for project developers provided that there is certainty that the transmission project costs will be recovered from a cost-causer or a beneficiary. The "someone" need not be fixed over the life of the facility in order for the developer to have reasonable assurance about the opportunity to recover its costs.

II. CONCLUSION

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate comments regarding the issues discussed in these comments. The following members generally support these comments.

Indiana Utility Regulatory Commission
Iowa Utilities Board
Michigan Public Service Commission
Minnesota Public Utilities Commission

[18] The OMS notes that the Commission has approved a cost allocation treatment that reimburses generators for 100% of qualifying interconnection costs in the ATC, ITC/METC, and ITC Midwest pricing zones of the Midwest ISO. The recent Commission order ER09-1431 RECB Phase I solution did not supersede the previously approved methodology for these zones. To the extent that these OMS comments do not contradict the policies approved by the Commission for these pricing zones, the Michigan PSC supports the OMS comments in this regard. Through the ongoing cost allocation forums such as CARP and RECB Phase II, etc the Michigan PSC will be examining alternative methodologies.

Montana Public Service Commission
North Dakota Public Service Commission
Public Utilities Commission of Ohio
Pennsylvania Public Utility Commission
South Dakota Public Utilities Commission

The Illinois Commerce Commission, the Kentucky Public Service Commission, the Missouri Public Service Commission and the Wisconsin Public Service Commission abstained from the vote on these comments. The Manitoba Public Utilities Board did not participate in this pleading.

The Minnesota Office of Energy Security and the Indiana Office of Utility Consumer Counselor, as associate members of the OMS, participated in these comments and generally support these comments.

Respectfully Submitted,

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Dated: November 23, 2009

Attachment B

CapX 2020 Technical Update:
Identifying Minnesota's
Electric Transmission Infrastructure Needs
October 2005

CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs

October 2005

EXECUTIVE SUMMARY

Background

Minnesota's electric transmission infrastructure, a network of transmission lines of 230 kilovolts and higher, primarily was designed and built during the 1960s and 1970s. As explained in CapX 2020's December 2004 interim report, the system is adequate to meet today's needs. But to support customers' growing demand for electricity, this high-voltage transmission system in Minnesota and neighboring states requires major upgrades and expansion during the next 15 years.

To ensure that this backbone transmission system is developed and available to serve growing demand for electricity and to plan for major capital expenditures, Minnesota's largest transmission-owning utilities—Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, and Xcel Energy—initiated the CapX 2020 project.

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region.
- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

The utilities have completed a draft study that defines a vision for transmission infrastructure investments needed in Minnesota through 2020. That technical study, which meets the first part of CapX 2020's mission, is described in this report. Studies will continue to determine which facilities will need to be built first. As other regional transmission studies are completed, they will be integrated into the CapX 2020 study. A report that describes progress on the second part of CapX 2020's mission, including pending legislation, is planned for this summer

Study overview

In developing this long-range plan for major new construction, the CapX 2020 technical team considered two potential scenarios for growth in electricity demand:

1. Anticipated load growth of 2.49 percent annually from 2009 through 2020, for an increase of 6,300 megawatts. This is based on load projections for utilities with customers in Minnesota, published by the Mid-Continent Area Power Pool (MAPP) in the *2004 MAPP Load and Capability Report* and in recent utility resource plan filings. Load growth of 6,300 MW would require over 8000 MW of new generation, given losses that occur when transmitting.
2. Slower load growth—about two-thirds of the published load projections—of 4,500 MW.

Based on information from independent power producers, wind developers, utility resource planning staff, and the Midwest Independent Transmission System Operator's generation interconnection queue, the team also worked out three generation scenarios, each including 2,400 MW of renewable energy, to illustrate potential locations of new electric generating plants or wind farms.

The goals were to identify new transmission *independent* of where plants are located *and* to identify new transmission *specific* to particular electric generation scenarios. The team considered planning requirements for meeting the Minnesota Renewable Energy Objective, addressed issues related to relieving transmission congestion, and focused on high-voltage solutions that best addressed the three different generation scenarios.

Results: The CapX 2020 Vision Plan

Facilities common to two of the three generation scenarios were identified as the cornerstone of the CapX 2020 Vision Plan—1,620 miles of 345 kV transmission lines that total $1.215 billion, about 80 percent of the cost of each scenario individually. The following table identifies these facilities. Any long-range vision plan also will have to include additional unique facilities for each scenario.

Facility Name				
From	**To**	**Volt (kV)**	**Miles**	**Cost ($M)**
Alexandria, MN	Benton County (St. Cloud, MN)	345	80	60
Alexandria, MN	Maple River (Fargo, ND)	345	126	94.5
Antelope Valley (Beulah, ND)	Jamestown, ND	345	185	138.75
Arrowhead (Duluth, MN)	Chisago County (Chisago City, MN)	345	120	90
Arrowhead (Duluth, MN)	Forbes (northwest Duluth, MN)	345	60	45
Benton County (St. Cloud, MN)	Chisago County (Chisago City, MN)	345	59	44.25
Benton County (St. Cloud, MN)	Granite Falls, MN	345	110	82.5
Benton County (St. Cloud, MN)	St. Bonifacius, MN	345	62	46.5
Blue Lake (southwest Twin Cities, MN)	Ellendale, MN	345	200	150
Chisago County (Chisago City, MN)	Prairie Island (Red Wing, MN)	345	82	61.5
Columbia	North LaCrosse	345	80	60

Ellendale, ND	Hettinger, ND	345	231	173.25
Rochester, MN	North LaCrosse	345	60	45
Jamestown, ND	Maple River (Fargo, ND)	345	107	80.25
Prairie Island (Red Wing, MN)	Rochester, MN	345	58	43.5
	Total miles 1620		**Total cost $1,215 ($M)**	

Conclusion

The CapX 2020 technical team believes the results documented here to be the basis for additional studies to better identify the transmission needs of the study region. The following report details the technical study behind this update. Section headings are:

- Base model assumptions
  (about loads and generation and how scenarios were determined, biases).
- Analysis
  (of study assumptions such as system conditions, contingencies, Big Stone II, and other sensitivities).
- Scenario analysis
  (of existing system performance, transmission alternatives, and line flows on interface and tie lines).
- Slow growth analysis.
- Common facilities.
- Conclusion and next steps.
- CapX 2020 Technical Team members.
- Appendices.

Although the existing transmission system is adequate to meet the reliability needs of customers today, the CapX 2020 study shows that the study region will experience specific and numerous transmission overloads, outages, and voltage problems if we make no transmission additions between now and 2020. Collaborative efforts and plans, such as those identified in this report, are necessary to reduce the risk of investing in new transmission infrastructure and to preserve electric reliability for customers.

1. Base Model Assumptions

The CapX study region encompasses the service territories of electric utilities that have load-serving responsibilities for Minnesota consumers. This region is represented in Diagram 1 below.

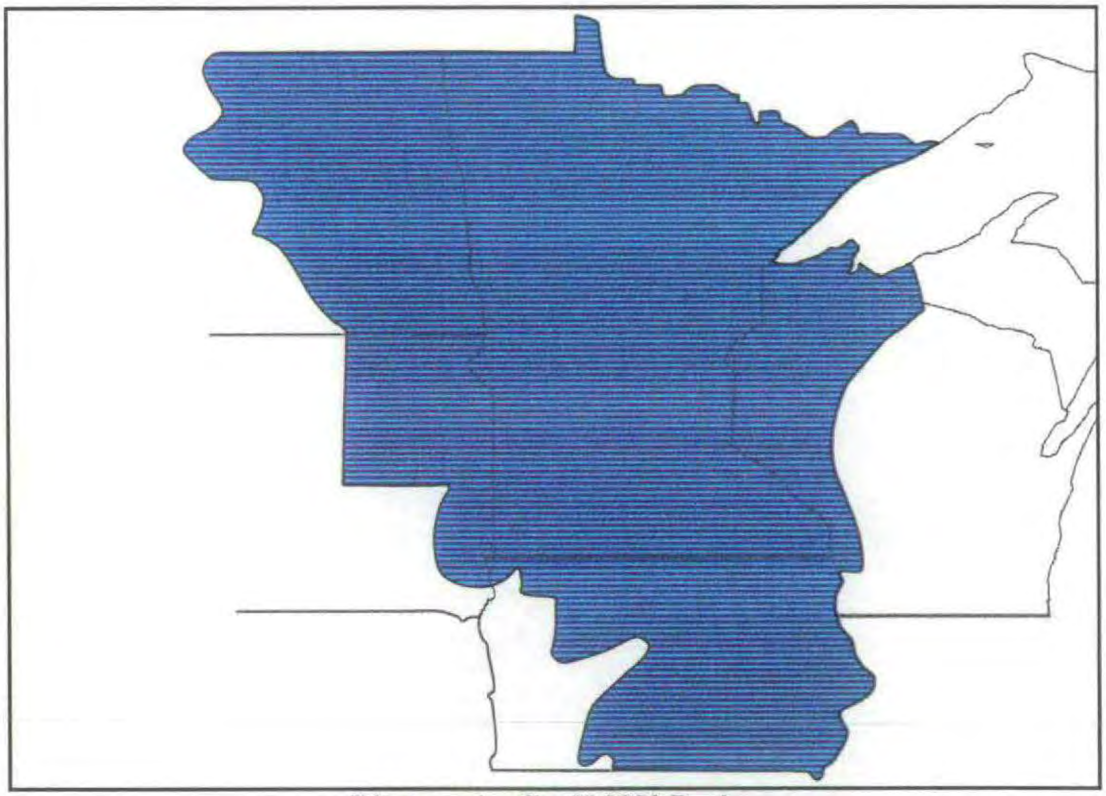

Diagram 1 – CapX 2020 Region

1.1 Loads

The CapX 2020 technical team chose the MAPP 2004 Series, 2009 summer peak model, as the base model to begin scaling loads to the anticipated 2020 load level. To accurately model 2020 loads, the technical team used individual company load growth from the *2004 MAPP Load and Capability Report* for the following control areas: Alliant Energy (west), Xcel Energy (north), Southern Minnesota Municipal Power Agency, Otter Tail Power Company, and Dairyland Power Cooperative.

Note that each control area contains not only load belonging to the control area operator, but also that of other companies. For example, Missouri River Energy Services has load in the Alliant Energy (west), Minnesota Power, Otter Tail Power Company, Western Area Power Administration, and Xcel Energy (north) control areas).

Minnesota Power and Great River Energy's loads were scaled based on their most recent resource plan filings. The growth results are in Table 1

Control area	2009 load level (2004 MAPP Series) (MW)	Yearly growth rate (%)	Calculated 2020 load level (MW)
ALT (West)	3265.3	1.60	3888.2
Xcel Energy (North)	9632.6	2.68	12885.1
MP	1507.3	1.70	1814.4
SMMPA/RPU	330.0	2.70	442.4
GRE	2833.5	3.27	3943.2
OTP/MPC	1677.2	2.70	2248.3
DPC	954.7	2.60	1266.2
Total	20200.6	Ave. = 2.49%	26487.8

Table 1 – CapX 2020 Anticipated Area Growth

Table 1 shows an anticipated load growth of approximately 6300 megawatts (MW) in the CapX 2020 region for the period from 2009 to 2020. The technical team also studied historical loads for Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, and Xcel Energy to determine whether anticipated load growth was consistent with historical load growth in the region. Load growth for these companies averaged 2.64 percent during the period 1980 to 2004. Diagram 2 shows the variability of load growth as well as the continuing upward growth in load for the region. The technical team's forecast from 2009 through 2020 is a slower growth curve than the actual growth in the early 2000's (2.49 percent vs. 2.64 percent).

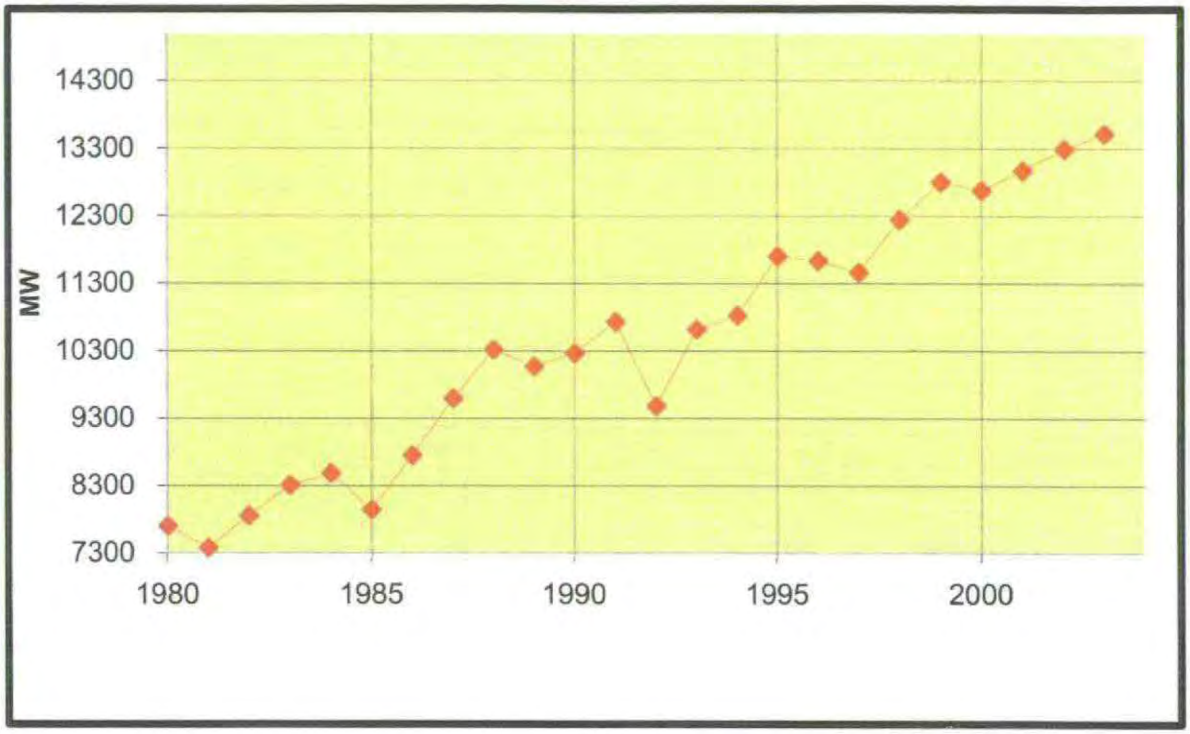

Diagram 2 – Historical Growth

1.2 Generation

The CapX 2020 technical team assumed that the generation modeled in the 2009 summer model would still exist in 2020 and would continue to serve the load modeled in 2009. To address anticipated load growth of 6,300 MW, the technical team solicited information from independent power producers (including wind developers), resource planning entities within various organizations, and the Midwest Independent System Operator's (MISO) generation interconnection queue.

Diagrams 3 and 4 are maps of potential generation addition locations that have been identified either from the MISO queue (Diagram 3) or from Wind on the Wires (which is a wind advocate organization) potential wind sites (Diagram 4).

The technical team combined this information to form potential generation development nodes, independent of fuel type, which they used in the modeling process to supply load increases.

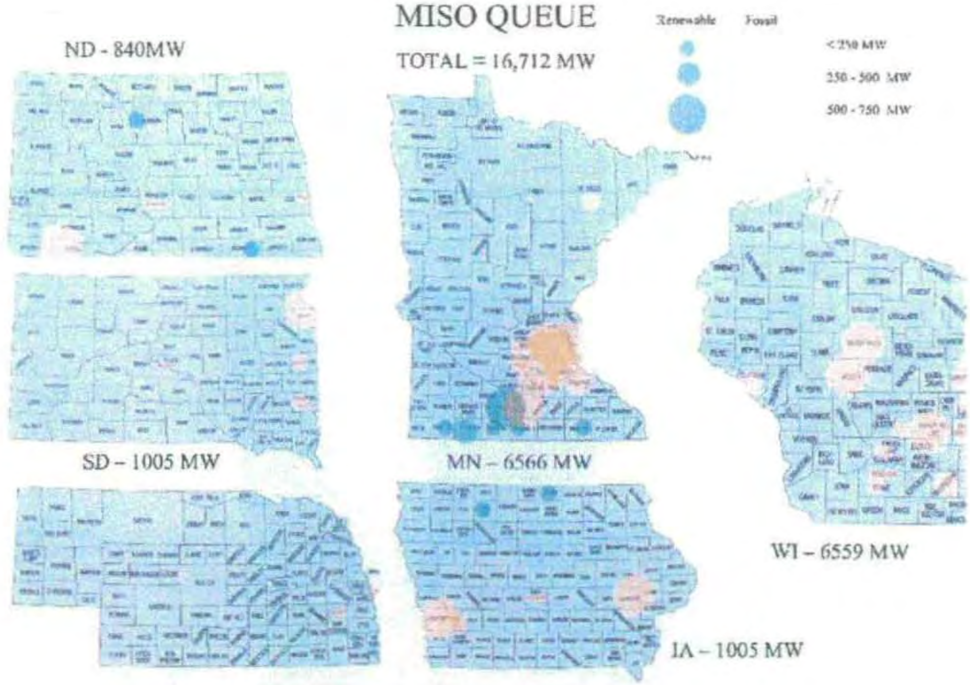

Diagram 3 – Potential Generation Areas

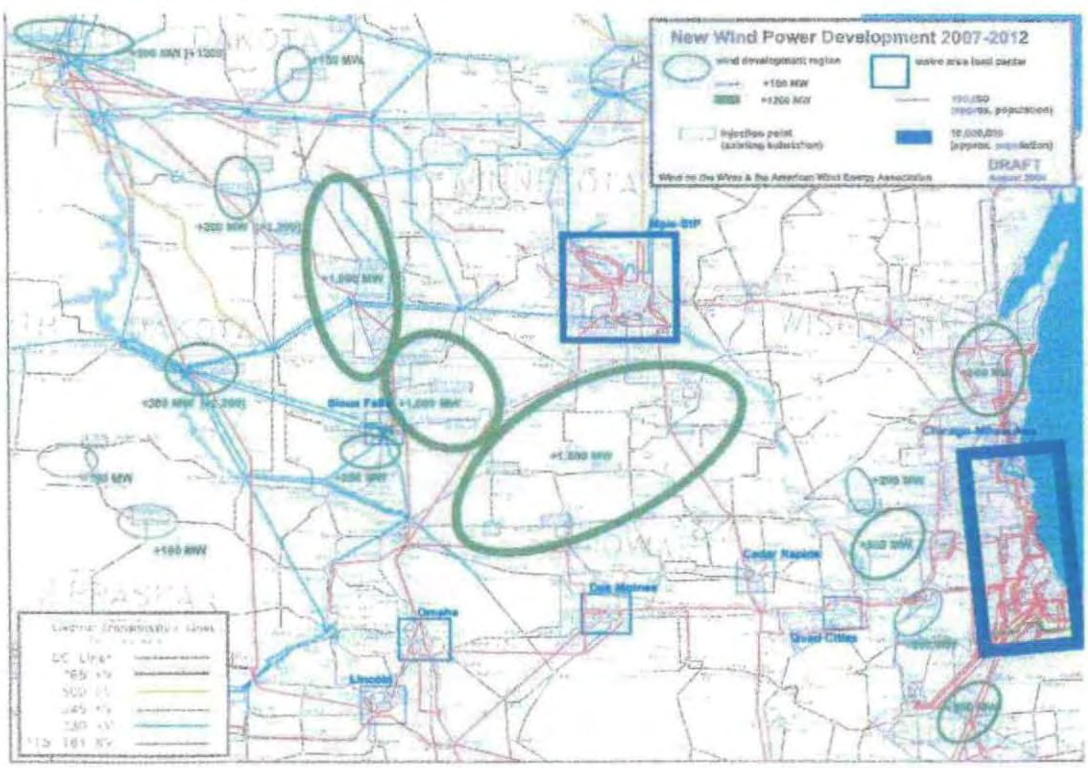

Diagram 4 – Potential Wind Generation Areas

The CapX 2020 technical team mapped the locations of these resources and identified five generation regions: Northern Minnesota, Dakotas (North Dakota and South Dakota), Southern Minnesota/Northern Iowa, Wisconsin and the Metro (Twin Cities Metropolitan) area. These regions are shown in Diagram 5.

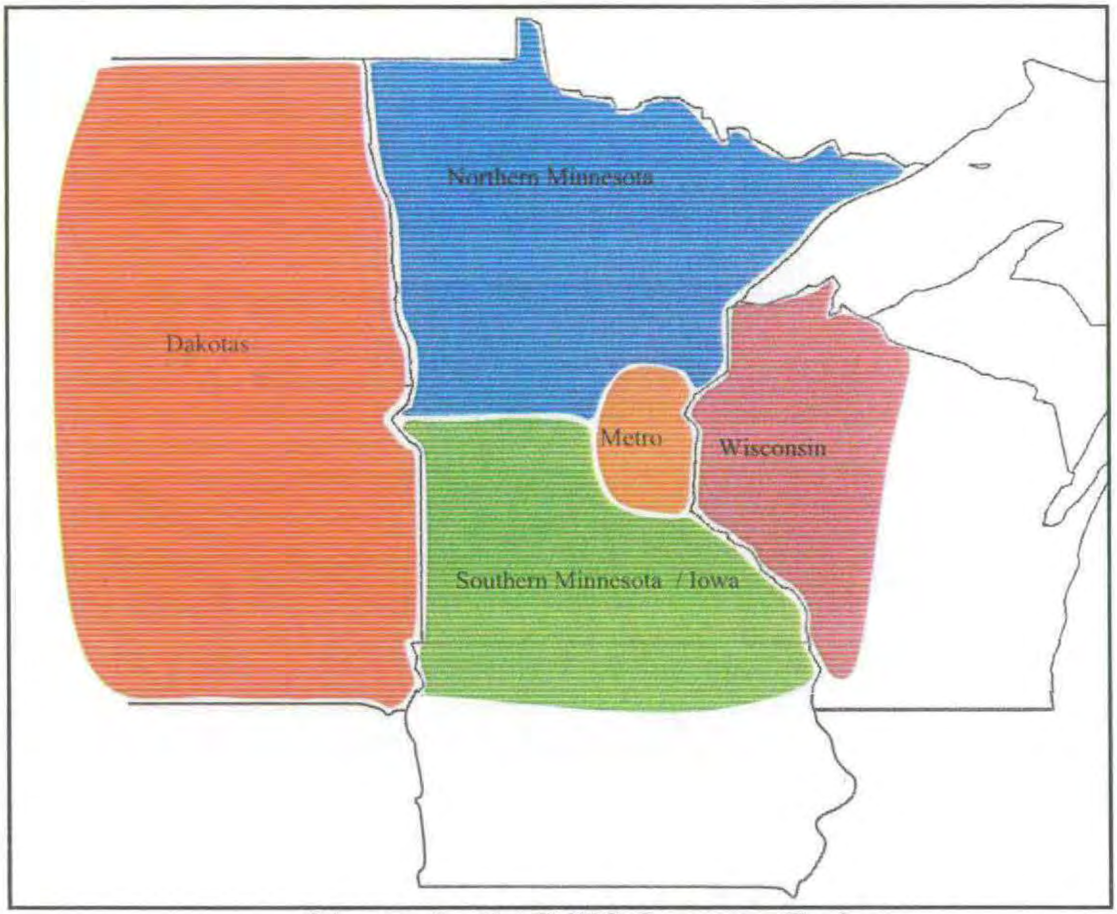

Diagram 5 – CapX 2020 Generation Regions

2.3 Scenario determination

The team modeled three generation scenarios to address the anticipated load growth of 6,300 MW from 2009 to 2020. Each of the scenarios includes sufficient renewable resources to address the Minnesota Renewable Energy Objective of the CapX 2020 participants.

The three generation scenarios consist of a North/West bias, a Minnesota bias, and an Eastern bias. These three generation biases reflect potential generation development that might influence electric power flows on the regional grid and thus indicate the size and location of new transmission infrastructure needed to deliver the generation to customers.

Each of the scenarios includes generation resources from several of the regions. See Table 2.

	Scenario		
Generation areas	North /West Bias	Minnesota Bias	Eastern Bias
Northern MN	1700[1]	1250	550
Dakotas	2100	1000	1600
Southern MN/ Iowa	1875	1875	2175
Metro	650	2200	1000
Wisconsin	0	0	1000
Total	6325	6325	6325

Table 2 – Generation Scenarios

Diagrams 6, 7, and 8 provide geographical representation of the regions for which generation will be modeled in each scenario.

2.3.1 North/West Bias Generation

In the north/west bias generation case the new generation modeled is more heavily based on importing generation into Minnesota from Manitoba, North Dakota, South Dakota, and Iowa.

The generation mix includes 2275 MW to meet Minnesota's Renewable Energy Objective: 975 MW from Minnesota and 1300 MW from outside of Minnesota. It also includes 1950 MW of other Minnesota generation and 2100 MW of other generation from outside of Minnesota.

Chart 1 below illustrates the north/west generation mix.

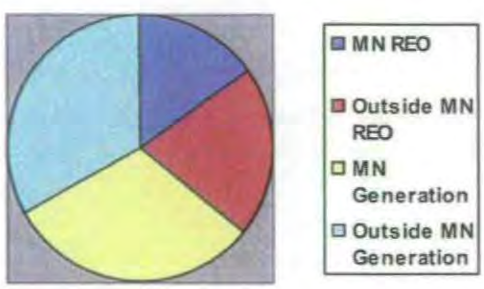

Chart 1 - North/West Bias Generation Mix

[1] This 1700-MW total includes a 1000-MW import from Manitoba.

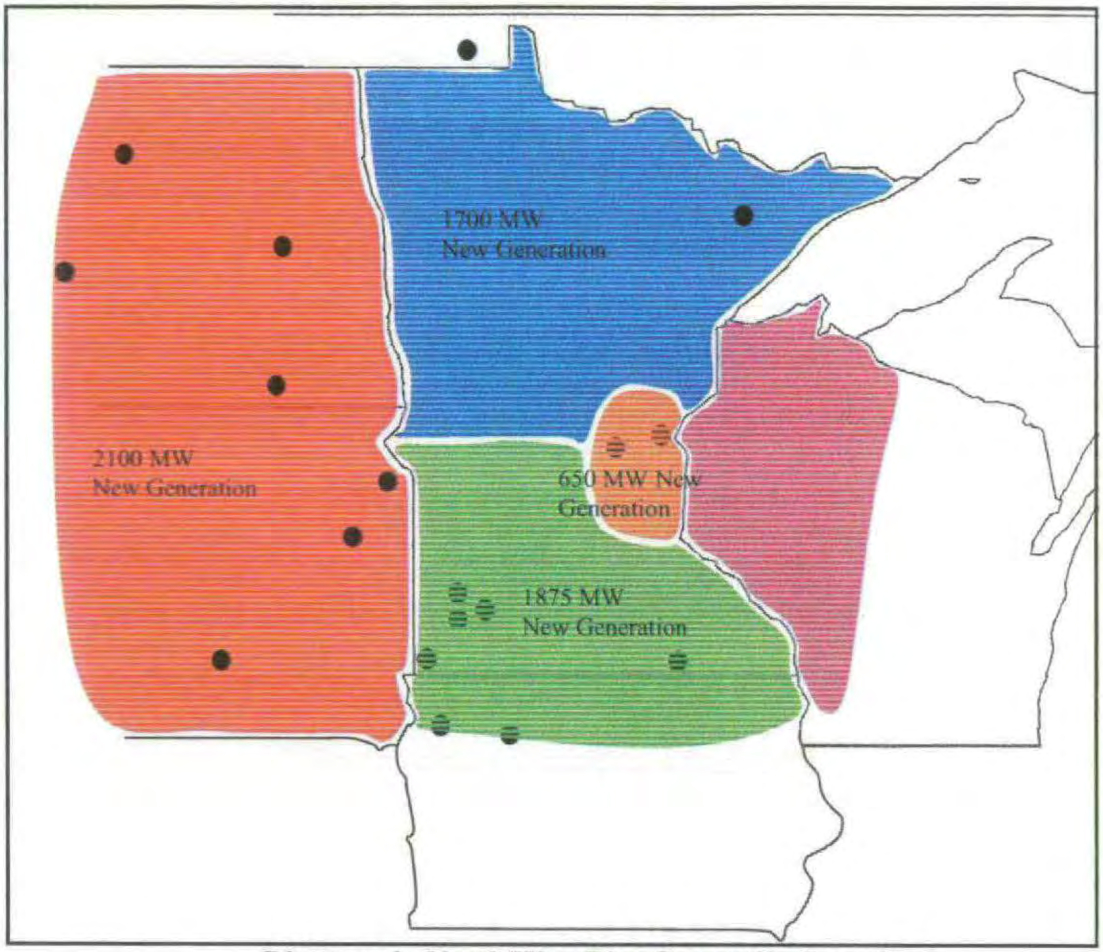

Diagram 6 - North/West Bias Generation Locations

2.3.2 Minnesota Bias Generation

In the Minnesota Bias Generation case all new generation outside of Minnesota (North Dakota, South Dakota, and Iowa) is modeled as 1300 MW of wind generation (REO). The generation modeled inside of Minnesota is a mixture of REO, peaking, and base load generation.

The generation mix includes 2275 MW of Renewable Energy Objective and 4050 MW of Minnesota generation.

Chart 2 below illustrates the Minnesota bias generation mix.

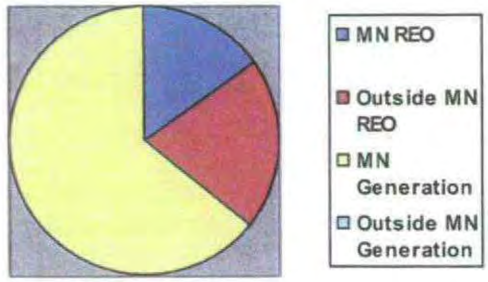

Chart 2 - Minnesota Bias Generation Mix Chart

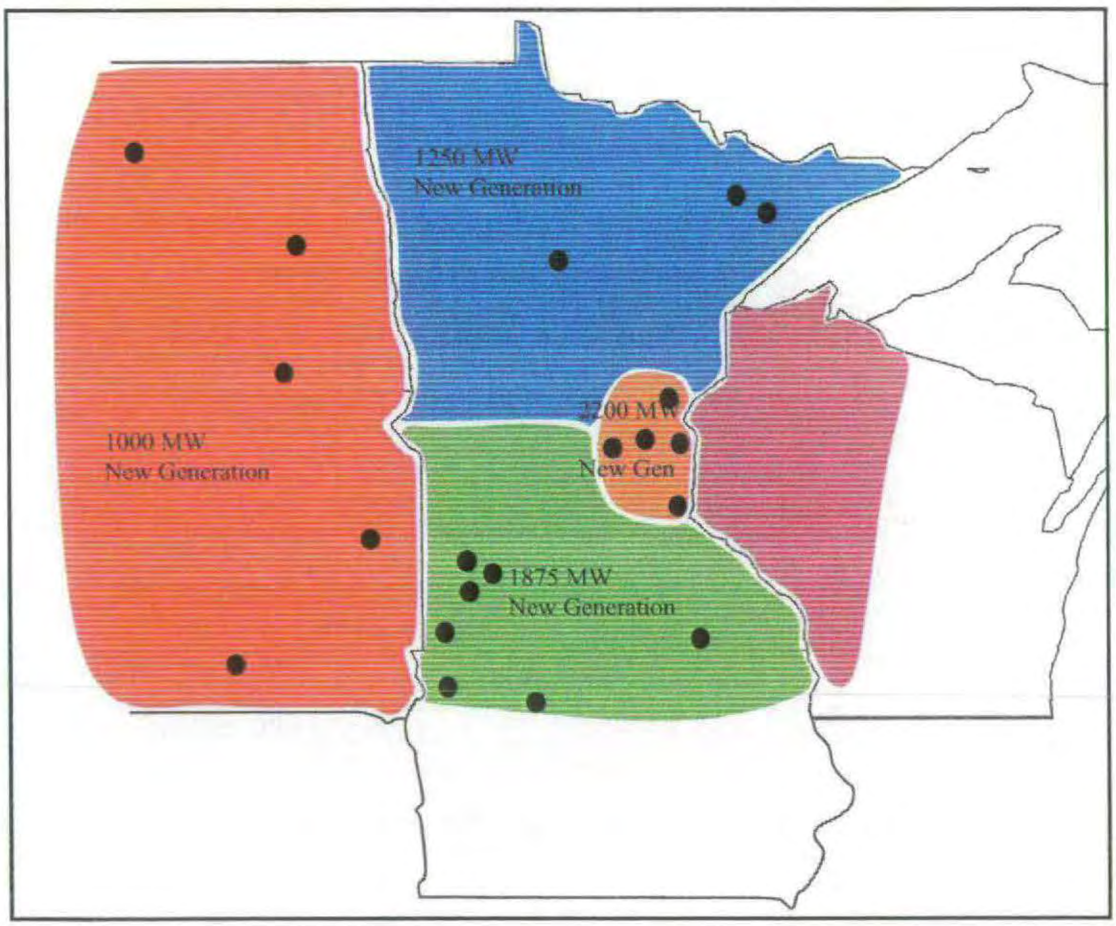

Diagram 7 - Minnesota Bias Generation Locations

2.3.3 Eastern Bias Generation

In the Eastern Bias generation case the new generation modeled is more heavily based on importing generation into Minnesota from Wisconsin and Iowa with 1000 MW new generation modeled in Wisconsin and 1050 MW of new generation modeled in Iowa.

The generation mix includes 2275 MW of Renewable Energy Objective (975 MW of Minnesota REO and 1300 MW from outside of Minnesota REO), 1700 MW of generation from inside of Minnesota, and 2350 MW of generation from outside of Minnesota.

Chart 3 below illustrates the Eastern bias generation mix.

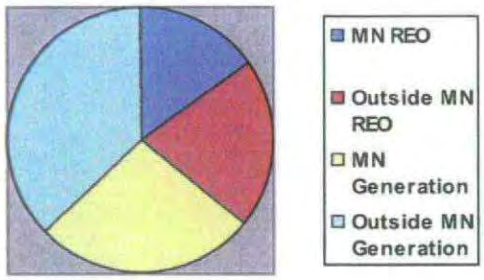

Chart 3 - Eastern Bias Generation Mix

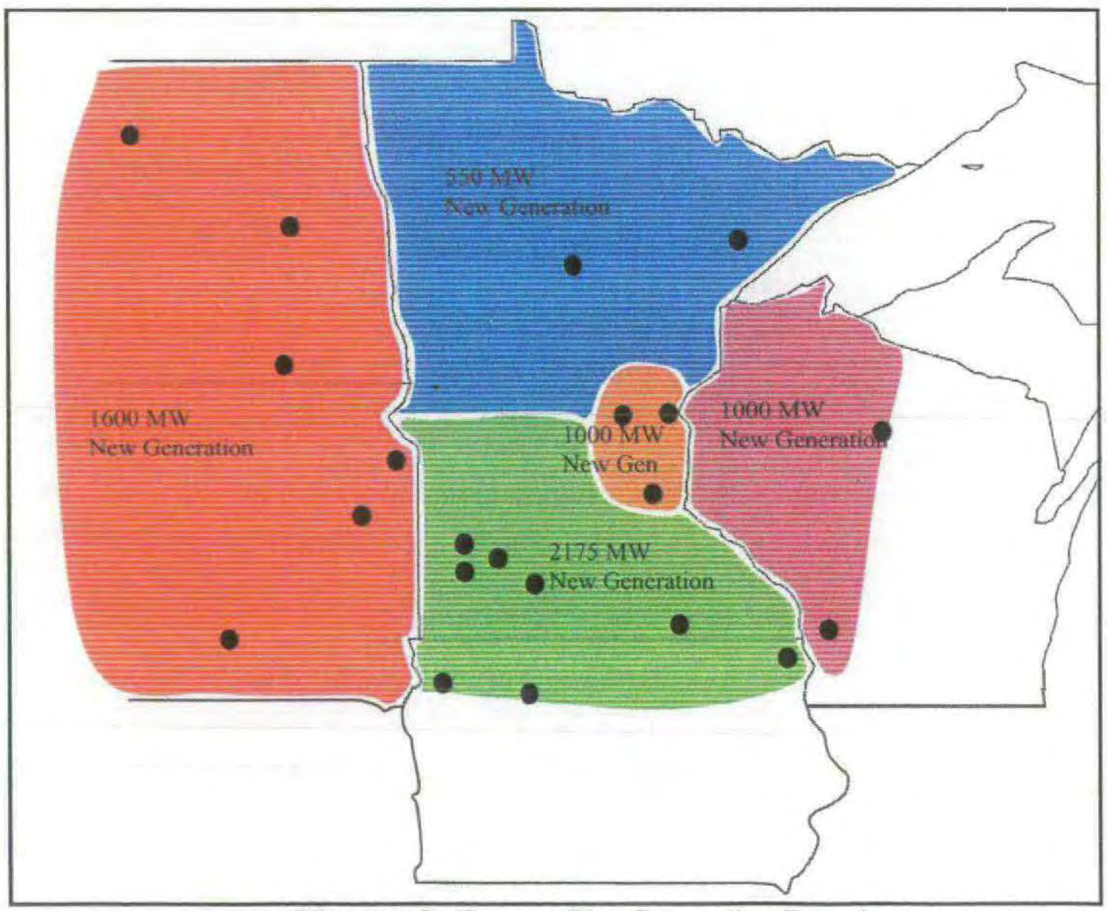

Diagram 8 - Eastern Bias Generation Locations

3 Analysis

The CapX 2020 technical team's primary goal was to create a common transmission backbone that could sustain system growth based on the three generation scenarios. In the future as specific generation is built, other transmission facilities will be required to tie the generation to the transmission backbone system and tie the load-serving centers to the local-serving distribution substations.

With this goal in mind, the team developed an initial list of possible transmission facilities. These facilities are shown in Diagram 9. Diagram 9 was created using inputs from various regional Midwest Independent System Operator (MISO) exploratory studies, the 2004 MISO Transmission Expansion Plan (MTEP '04), as well as input from utility transmission planners in the study area. The team purposely kept lines vague, leaving the routes and endpoints to be determined as study work progressed. Transmission alternatives were limited to facilities 345 kilovolts and larger for the purpose of this vision study of the high voltage bulk transmission study.

The technical team incorporated transmission alternatives identified in on-going studies in conjunction with transmission plans identified by various transmission stakeholders. The goals were to identify transmission improvements that connect remote generation to the load-serving centers in the region and to develop a transmission backbone that supports continued load growth in the various load centers. The transmission improvements focused on high voltage solutions (345 kV lines and 500 kV lines) that best addressed the load areas and the various generation scenarios.

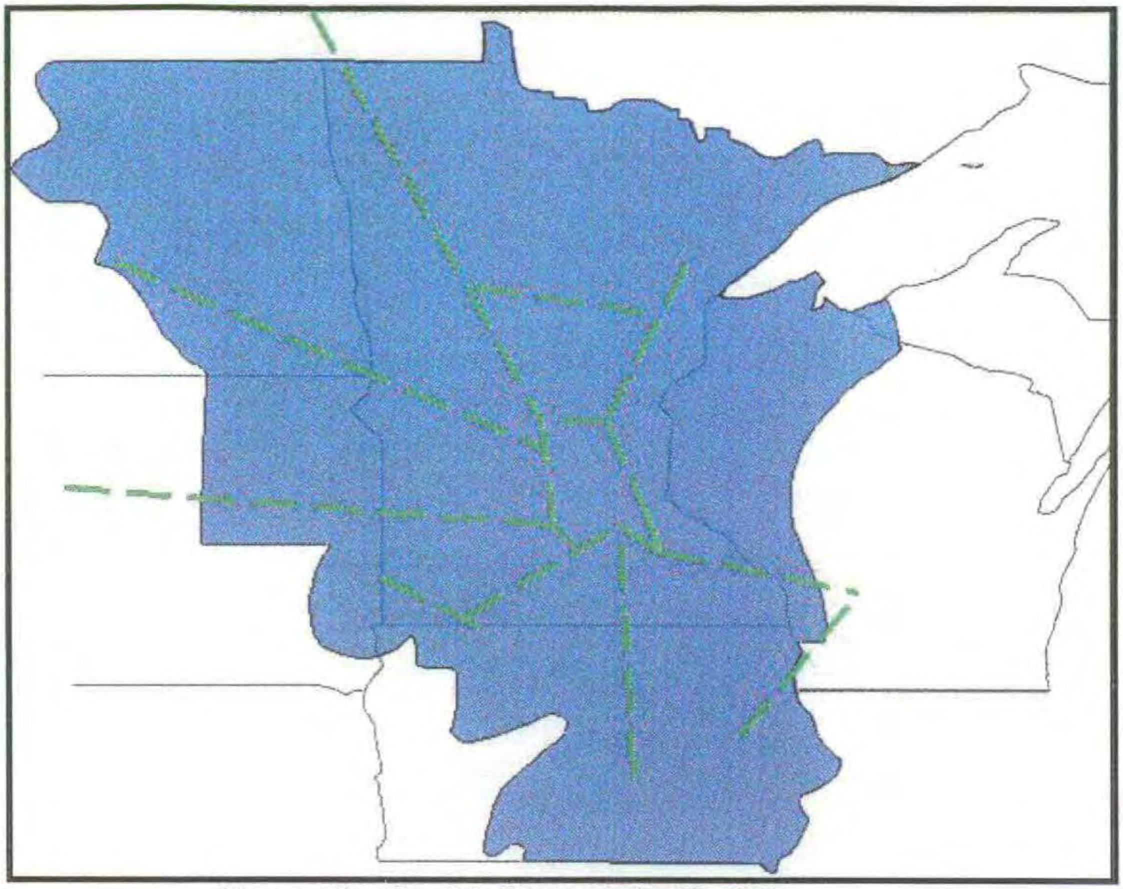

Diagram 9 – Possible Transmission Facilities

As a starting point, the technical team utilized the most probable transmission options from the exploratory studies already underway in the MISO/MAPP footprint, most notably the Southwest Minnesota/ Northern Iowa study and the Northwest Exploratory study. These transmission options are shown below:

- A 345 kV line from the North Dakota coal fields to Fargo and continuing to near St. Cloud, Minnesota
- A 345 kV line from Prairie Island, near Red Wing, Minnesota, to Rochester, Minnesota, and continuing to southwest Wisconsin
- Two 345 kV lines into central Iowa
- A 345 kV or 500 kV line from Manitoba into near St. Cloud, Minnesota.
- Generation outlet transmission facilities presently under study through MISO.

Once these lines were placed on the map, the technical team analyzed the system for the best regional method to tie all these study results together, while maximizing load-serving potential for the entire region well into the future. The team also created a second 345 kV transmission ring around the wider Twin Cities metro area, with "spokes" leading out to the smaller load and/or generation pockets in the region.

A complete list of the potential transmission facilities is included in Appendix A.

3.1 Study Assumptions

3.1.1 System Condition Assumptions

The CapX 2020 study was based on a system snapshot with the best-known 2020 state of the transmission system as of August 2004 for the MAPP region. Since August 2004, very few changes have been made to the base case model. In the last ten months, load, generation and transmission modeling may have been modified in other studies, which the CapX 2020 study does not reflect.

3.1.2 Contingency Analysis Assumptions

The technical team tested several transmission solutions for each generation scenario and performed steady-state powerflow analysis (first contingency simulations) to determine which transmission solution eliminates thermal overloads on transmission lines 161 kV and higher in the region. Because the intent of this study was bulk level load serving, the technical team decided to model all generation on the highest voltage bus available local to the generation, and to run the contingency simulations on a limited list of facilities, namely 161 kV and above.

When reviewing the results of this study, note that only the bulk system overloads and solution are represented. None of the associated substation, generation interconnection facilities, or underlying lower-voltage (below 161 kV) transmission system infrastructure was studied.

3.1.3 Big Stone II Inclusion in the CapX 2020 Vision Study

Interconnection steady-state results from the Big Stone II generation study were completed in the late fall 2004 and, therefore, were included in the CapX 2020 Vision Study. Big Stone II was modeled in the north/west and eastern biases. In the north/west bias, the generator was modeled along with the outlet options that included:

- Big Stone – Canby new 230 kV line
- Canby – Granite Falls 115 kV line converted to 230 kV
- Big Stone – Willmar new 230 kV line

The eastern bias included the generator along with outlet options that included:

- Big Stone – Canby, Minnesota, new 230 kV line
- Canby – Granite Falls, Minnesota, 115 kV line converted to 230 kV
- Big Stone – Ortonville, Minnesota, new 230 kV-line
- Ortonville – Johnson Jct. - Morris, Minnesota, 115 kV line converted to 230 kV

Because the Minnesota bias focused on generation located within state boundaries with the exception of wind resources, Big Stone II, which is a potential coal-fired plant in South Dakota, was not included in this generation bias.

Based on the results from this vision study, the Minnesota and north/west generation biases include a new 345 kV line from Granite Falls, Minnesota, to Benton County (St. Cloud), Minnesota, and all three generation scenarios include a new 345 kV line from Ellendale, North Dakota, to Blue Lake (Mpls/St. Paul), Minnesota, regardless of whether Big Stone II was included. These lines could be instrumental to wind outlet in the North Dakota and South Dakota.

3.1.4 Sensitivities to Current Area Study Work

- Big Stone II was partially included in this vision study as described in section 3.1.3 above. Because the Big Stone II interconnection study was completed during the CapX 2020 technical study timeframe, variations of the interconnection study results were included in the CapX 2020 study. When a certificate of need (CON) is filed for Big Stone II, a vision study sensitivity will be completed to determine how the Big Stone II project proposed facilities fit into the timeline for the CapX 2020 vision study facility additions.
- Buffalo Ridge Incremental Study conducted by Xcel Energy in the winter of 2004 through spring 2005 had no public results available to include during the CapX 2020 case development time. In addition, the Buffalo Ridge study is a lower voltage study than the CapX 2020 focus.

4 Scenario Analysis

The preliminary base case model for the year 2020 includes the 6300 MW of anticipated load growth and the new generation to meet and serve the growth, however the base case doesn't contain any new necessary transmission facilities.[2] The CapX 2020 technical team's preliminary base case analysis of the three generation scenarios identified a significant number of transmission overloads that could occur if no additional transmission is built to serve the projected load growth and the new generation needed by 2020 to meet this growth. The team simulated the loss (outage) of single transmission elements (n-1 analysis) to help determine transmission alternatives to address potential violations of North American Electric Reliability Council criteria, such as low voltages and thermally overloaded facilities.

Power Technology's PSS/E program, Version 29, was used to perform this analysis. Within PSS/E, the activity called ACCC, or AC Contingency Checking, was used as a first check of the entire study area to find problems. ACCC sequentially examines all relevant single contingencies in the region of interest for a given load and transfer base case. Facilities identified in the ACCC outputs were considered limiters if they had line outage distribution factors of 2 percent or greater. Bus voltages lower than 0.9 per unit were also flagged.

For the more detailed analysis of each scenario, the team used a contingency program developed by Great River Energy. The contingency program uses the IPLAN programming language within PSS/E. It performs many functions on the user-defined model, including developing user-defined contingencies with appropriate line-switching procedures, monitoring files for bus voltage and line loading violations, and the output files are then easily imported into Microsoft Excel. Transmission facilities identified in the Excel outputs were considered limiters if they had power transfer distribution factors and/or line outage

[2] Exception: The north/west bias base 2020 case includes a 345 kV facility from Manitoba to near St Cloud, MN

distribution factors of 2 percent or greater. Bus voltages lower than 0.9 per unit were also flagged

For the n-1 analysis, the team ran transmission contingencies and monitored the transmission system in the following control areas:

Control area	PSS/E area #
Alliant Energy West	331
Xcel Energy	600
Minnesota Power	608
Southern Minnesota Municipal Power Agency	613
Great River Energy	618
Otter Tail Power Company	626
Dairyland Power Company	680

4.1 Existing System Performance / Base Case Analysis

The ACCC activity performs all contingencies in the area and, therefore, provides an excellent screening tool for determining as to when and where violations of the planning criteria occur.

Initially, the team ran ACCC on the existing system for the three generation scenario bias cases: Peak load with all the Minnesota bias generation on-line at the 2020 load levels, peak load with all the north/west bias generation on-line at the with 2020 load levels, and peak load with all the eastern bias generation on-line at the 2020 load levels. The team temporarily put aside base case results but eventually will compare them with the post-new facility results for each bias to find the most effective set of 345 kV and higher transmission infrastructure additions to meet the 6,300 MW of new load. The base case system n-1 results are included in Appendix B of this report for each bias case.

Table 3 shows the number of overloaded transmission facilities and voltage violations in the base case 2020 models. Sections 4.2 through 4.5 of this report will discuss the results for each scenario in further detail. Again, n-1 contingency output results are tabulated in Appendix B.

Scenario	System Intact Overloads	n-1 Overload Violations[3]	Voltage Violations
North/West Bias[4]	42	142	45
Minnesota Bias	42	187	14
Eastern Bias	42	197	33

Table 3 – Base Case 2020 Transmission System Violations

[3] Outages of individual facilities 161 kV and higher were simulated.

[4] Includes the addition of a 345 kV facility from Manitoba to near St. Cloud, Minnesota

4.2 Transmission Alternatives

As mentioned previously in this report, Appendix A of this report includes a complete list of all transmission facilities 345 kV and higher that the CapX 2020 technical team considered. The team analyzed each generation scenario separately to determine which of these facilities would most effectively solve thermal and voltage violations on the bulk (161 kV and higher) transmission system in the study area. To do this, the team inserted specific facilities or facility groups from Appendix A one at a time into the model to assess each facility's benefits.

The team selected facilities to insert into the model by determining the location of the need for system improvement. The team recommended as facility additions those facilities that had the greatest benefit to the system by reducing the thermal overload and/or solving voltage violations during n-1 contingency.

The results of the facility addition benefits are shown in Appendix B in the n-1 contingency output result tables for each generation scenario.

4.3 Minnesota Bias Scenario Results

4.3.1 Recommended Transmission Vision Facilities

Diagram 10 shows the final compilation of recommended transmission facilities for the Minnesota bias based on the n-1 contingency analysis completed using the facilities in Appendix A and Table 4. All contingency analysis results and PSS/E automaps are included in Appendix B-1.

Ref. Ref.#	Data Source	Facility name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton County	Granite Falls	345	110	82.5
F-11	MH	Benton County	Riverton	345	78	58.5
F-12	CAPX	Benton County	St. Boni	345	62	46.5
F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-17	CAPX	Boswell	Forbes	345	64	48

F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-32	CAPX	Forbes	Riverton	345	114	85.5
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
F-63	CAPX	Lakefield Jct	Adams	345	92	69
				Total	**1968**	**1,476**

CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

Table 4 – Minnesota Bias Recommended Facilities

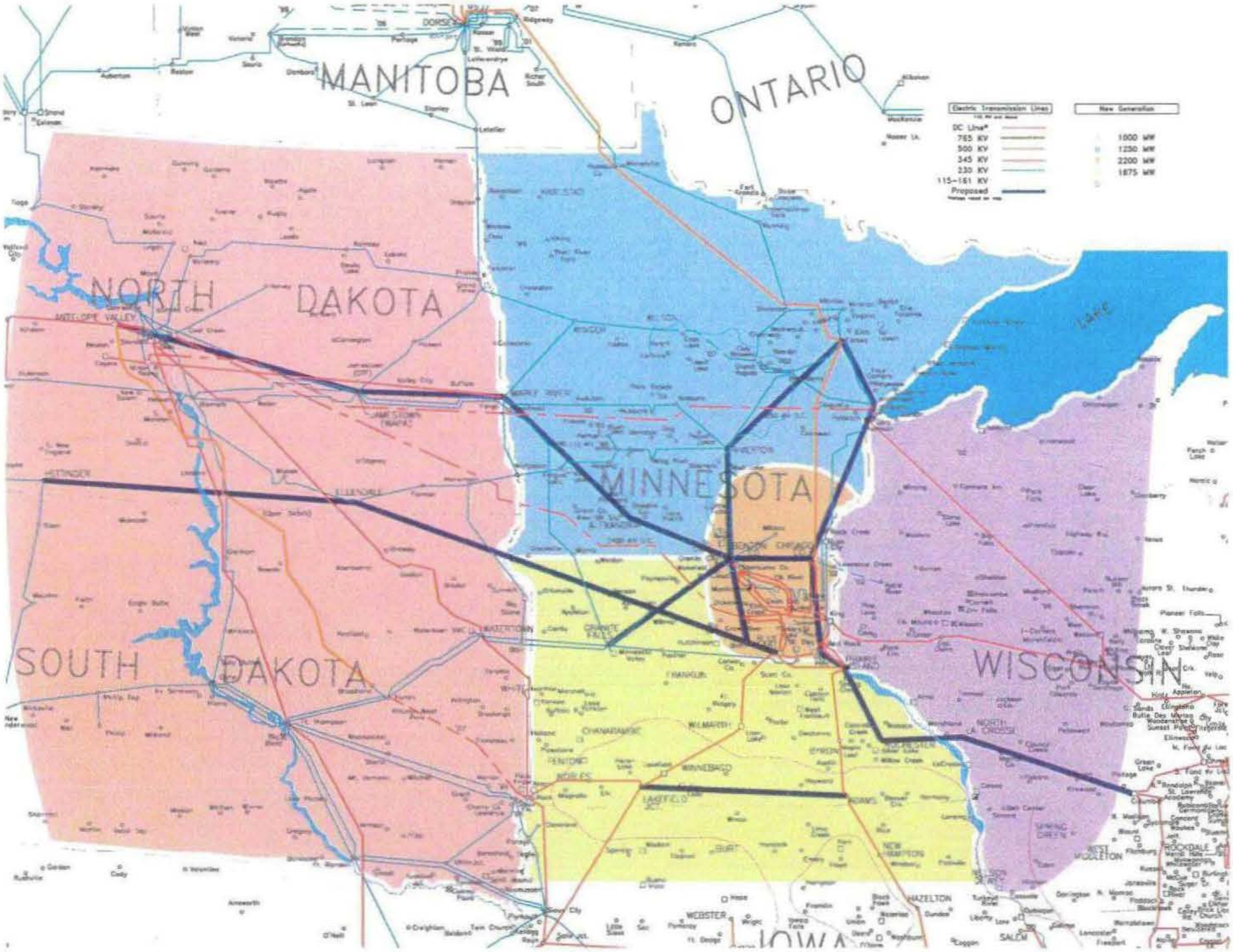

Diagram 10 – Minnesota Bias Recommended Facilities

4.3.2 Line Flows on Interface and Tie Lines

The CapX 2020 technical team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 5 predominantly focuses on lines coming into and going out of Minnesota, including some lines internal to Minnesota connecting pockets of transmission. Table 5 shows that adding the facilities recommended for the Minnesota bias scenario mostly causes reductions in MW flow over these 230 kV and higher interfaces.

LINE	kV Voltage Level	Base 6300 MW flow (MW)	6300 mw UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	870	687	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1418	1308	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	170	183	Manitoba Hydro to northern Minnesota
Letellier – Drayton	230 kV	325	300	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	18	2	Manitoba Hydro – North Dakota (this and the 3 lines above are all that ties Manitoba and U.S. as planned of 2009)
Arrowhead – Stone Lake	345 kV	116	97	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	111	87	West to central Wisconsin
Prairie Island – Byron	345 kV	116	320	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	127	50	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	768	594	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	175	159	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	300	285	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	315	292	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	329	317	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	263	220	Western Minnesota
Fargo – Moorhead	230 kV	53	62	Fargo, North Dakota, to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	260	162	North Dakota, Minnesota border
Maple River – Winger	230 kV	76	69	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	138	84	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	234	153	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	53	51	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	220	114	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	10	26	Coming from the north into St Cloud
Sheyenne – Audubon	230 kV	214	178	Fargo area west into Minnesota
Genoa – Coulee	161 kV	263	204	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	291	192	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	283	187	Northern Minnesota

Table 5 – Minnesota Bias Tie Line / Interface Flows

4.4 North / West Scenario Results

4.4.1 Recommended Transmission Vision Facilities

Diagram 11 shows the final compilation of recommended facilities for the North/West Bias based on the n-1 contingency analysis using the facilities in Appendix A and Table 6. All contingency analysis results and PSS/E automaps are included in Appendix B-2.

Ref. Ref.#	Data Source	Facility Name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton County	Granite Falls	345	110	82.5
F-12	CAPX	Benton County	St. Boni	345	62	46.5
F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-29	MH	Dorsey	Karlstad	345	134	100.5
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-45	MH	Karlstad	Winger	345	91	68
F-40	MH	Winger	Benton Co.	345	162	121.5
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
	Total				**2007**	**1,505**

Table 6 – North/West Bias Recommended Facilities

Key for Table 6:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

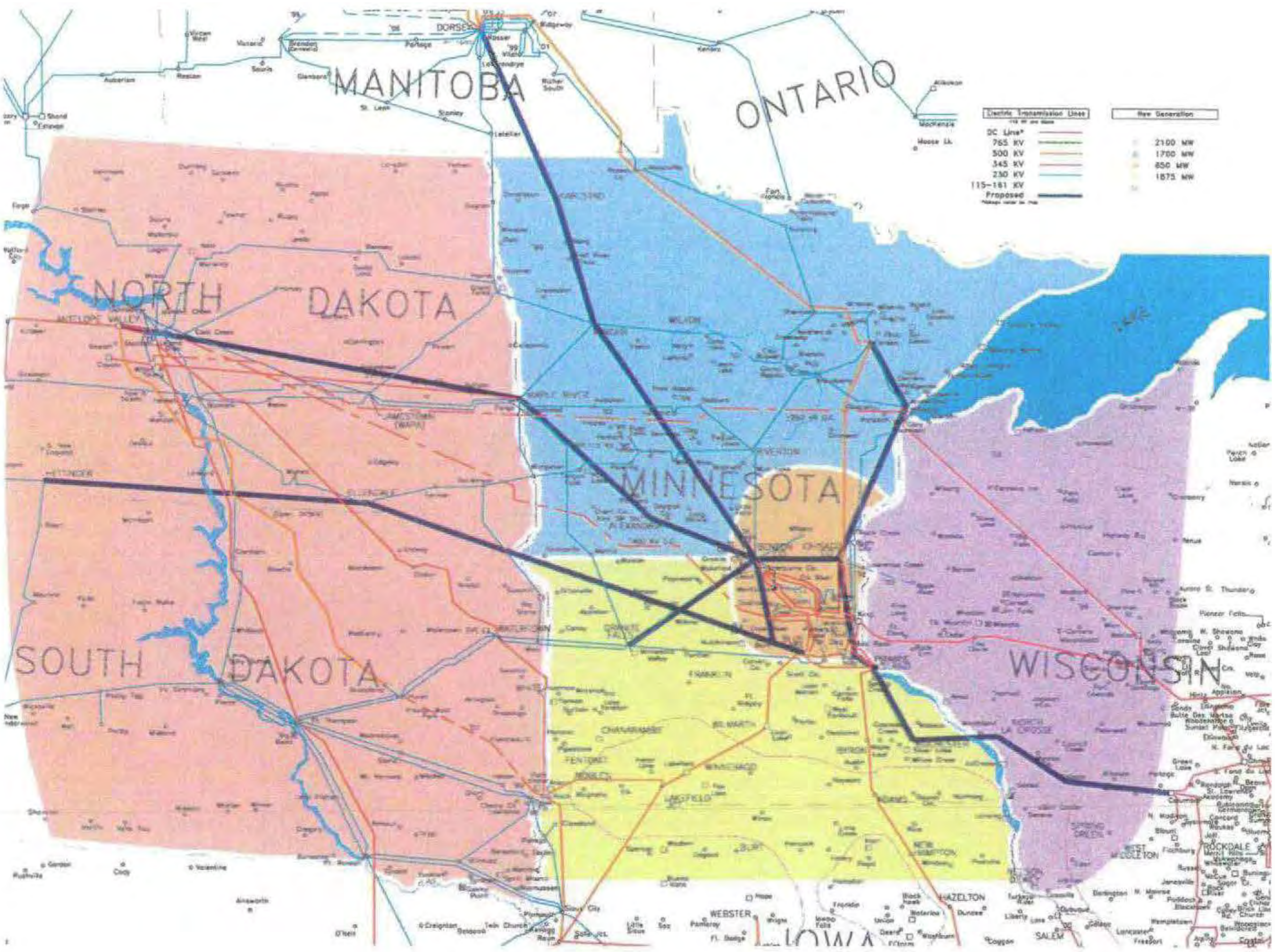

Diagram 11 – North/West Bias Recommended Facilities

4.4.2 Line Flows on Interface and Tie Lines

The Technical Team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 7 predominantly focuses on lines coming into and going out of Minnesota, including some lines internal to Minnesota connecting pockets of transmission.

The table shows that adding the facilities recommended for the north /west bias scenario causes about equal amounts of reductions and additions in MW flow over these 230 kV-and-higher interfaces. Note that in this north/west scenario the Manitoba Hydro flows are lower than in the slow growth scenario Manitoba Hydro export. The reason for this difference is that the CapX technical team has added the 345 kV line in the 6,300 MW load base case, which has 816 megavolt amperes flowing on it.

LINE	kV Voltage Level	Base 6300 MW flow (MW)	6300 MW UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	1507.7	1343.3	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1591.8	1507.5	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	219.2	212.8	Manitoba Hydro to northern Minnesota
Letellier – Drayton	230 kV	286.5	303.7	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	64.4	10.6	Manitoba Hydro – North Dakota (This and the 3 lines above are all that ties Manitoba and U.S. as planned through 2009.)
Arrowhead – Stone Lake	345 kV	271.0	295.4	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	148.4	71.0	West to central Wisconsin
Prairie Island – Byron	345 kV	284.4	277.3	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	274.1	156.6	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	978.5	819.3	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	350.7	261.6	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	500.7	409.9	Northwest of Worthington to Lakefield Jct. sub (Minnesota)
Watertown – Granite Falls	230 kV	293.0	245.0	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	334.5	292.4	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	455.5	404.4	Western Minnesota
Fargo – Moorhead	230 kV	50.8	39.1	Fargo, North Dakota to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	286.6	230.0	North Dakota, Minnesota border
Maple River – Winger	230 kV	64.3	20.9	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	110.0	70.8	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	277.8	213.4	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	89.6	90.0	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	203.5	175.0	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	47.6	36.6	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	265.4	233.0	Fargo area west into Minnesota
Genoa – Coulee	161 kV	278.0	212.0	Western Wisconsin

Boswell – Blackberry Ckt 1	230 kV	284.4	276.2	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	277.6	269.7	Northern Minnesota

Table 7 – North/West Bias Tie Line/Interface Flows

4.5 Eastern Bias

In the eastern bias scenario, the CapX 2020 technical team added part of the additional generation to the east of Minnesota (part on the border of northeastern Iowa and southwestern Wisconsin, part central Wisconsin), in addition to having generation throughout Minnesota, northern Iowa, North Dakota, and South Dakota as in the other two scenarios.

4.5.1 Recommended Transmission Vision Facilities

		Facility Name				
Ref. #	Data Source	From	To	Volt (kV)	Miles	Cost ($M)
F-56	SMNI	Prairie Island	Rochester	345	58	43.7
F-64	CAPX	Eau Claire	King	345	84	63.1
F-65	CAPX	N. LaCrosse	Eau Claire	345	73	55.1
F-66	CAPX	Genoa	N LaCrosse	345	42	31.7
F-67	CAPX	Genoa	Columbia	345	113	84.8
F-68	CAPX	Genoa	Nelson Dewey	345	70	52.4
F-69	SMNI	Nelson Dewey	Salem	345	34	25.6
F-70	CAPX	Genoa	Lansing	345	21	15.8
F-71	CAPX	Lansing	Rochester	345	89	66.8
F-72	CAPX	Ellendale	Big Stone	345	194	145.8
F-73	CAPX	Big Stone	Blue Lake	345	71	53.4
F-02	TIPS	Maple River	Benton Co	345	206	154.5
F-03	NW	Antelope Va.	Maple River	345	292	218.8
F-07	CapX	Arrowhead	Chisago	345	120	90
F-08	CapX	Arrowhead	Forbes	345	60	45
F-09	CapX	Benton Co	Chisago	345	59	44.2
F-10	CapX	Benton Co	Granite Falls	345	110	82.5
F-12	CapX	Benton Co	St Boni	345	62	46.5
F-26	CapX	Chisago Co	Prairie Island	345	82	61.5
F-30	NW	Ellendale	Hettinger	345	231	218.8
			Total		**2071**	**1,600**

Table 8 – Eastern Bias Recommended Facilities

Key for Table 8:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study

SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

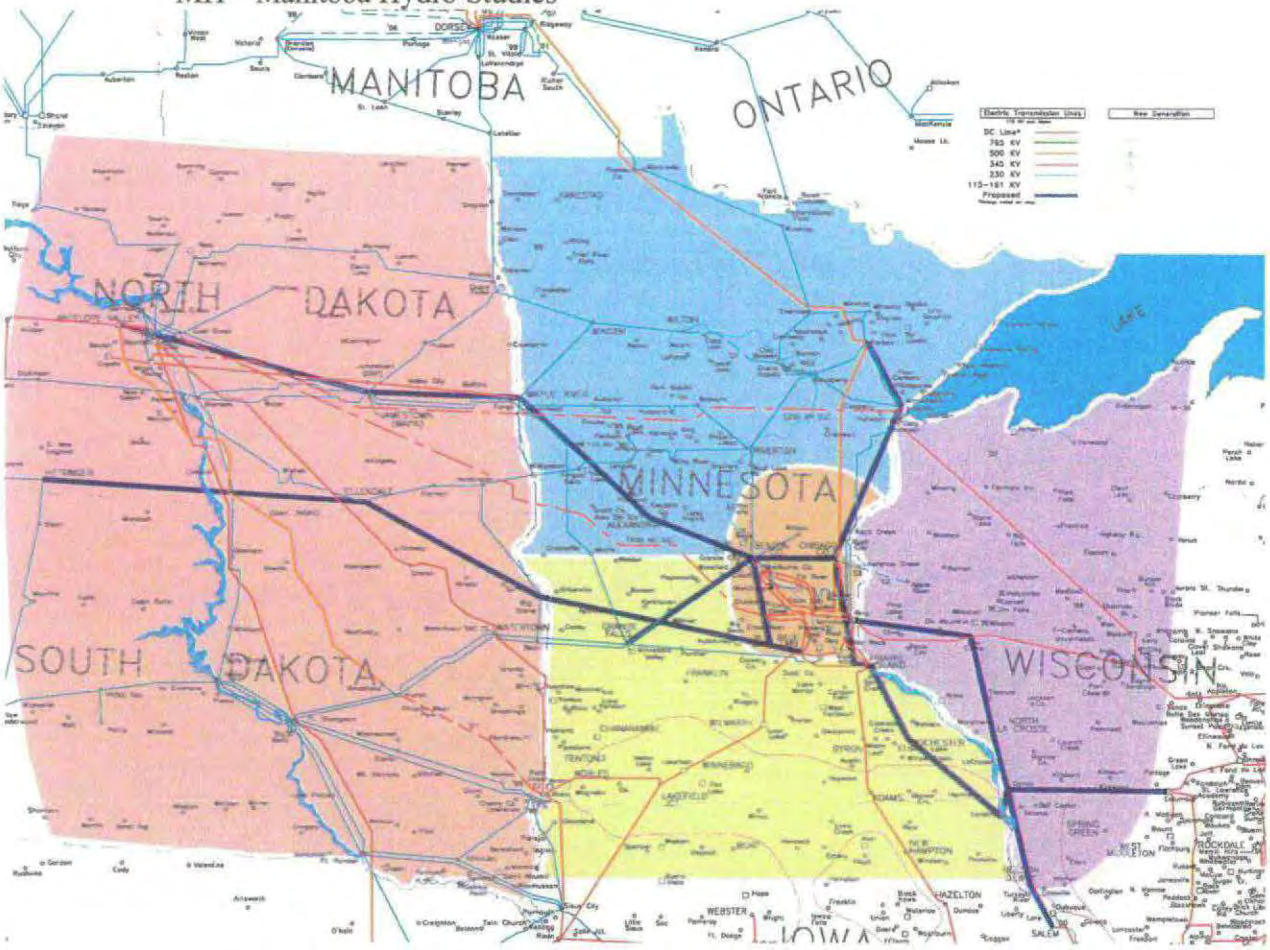

Diagram 12 – Eastern Bias Recommended Facilities

4.5.2 Line Flows on Interface and Tie Lines

The CapX 2020 technical team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 9 predominantly focuses on lines coming into and going out of Minnesota, including some lines inside Minnesota connecting pockets of transmission.

LINE	kV Voltage Level	Base 6300 MW flow (MW)	6300 MW UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	1209.6	1191.7	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1344.9	1329.6	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	178.8	177.7	Manitoba Hydro to northern Minnesota

Letellier – Drayton	230 kV	306.5	314.1	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	-26.9	-18.6	Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.)
Arrowhead – Stone Lake	345 kV	177.1	174.5	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	-174.1	-41.8	West to central Wisconsin
Prairie Island – Byron	345 kV	-380.5	-263.7	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	-138.5	-12.5	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	724.4	660.1	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	97.9	81.1	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	279.4	265.4	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	234.2	224.2	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	276.8	269.9	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	373.6	362.8	Western Minnesota
Fargo – Moorhead	230 kV	-23.1	-21.4	Fargo, North Dakota, to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	305.9	297.2	North Dakota, Minnesota border
Maple River – Winger	230 kV	91.5	88.5	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	129.2	129.3	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	242.6	234.9	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	93.1	92.5	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	227.0	233.4	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	38.3	31.5	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	230.6	222.3	Fargo area west into Minnesota
Genoa – Coulee	161 kV	391.9	210.8	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	279.9	280.3	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	273.2	273.5	Northern Minnesota

Table 9 – Eastern Bias Tie Line/Interface Flows

4 Slow Growth Analysis

The CapX 2020 technical team performed a sensitivity analysis for a reduced load level of 4,500 MW to determine which facility additions are necessary at this slower growth load level. Assuming the 6,300 MW increased load level is reached in 2020 and using a linear load growth rate, the team determined that the 4,500 MW increased load level would be reached in the year 2016.

To model the 4,500 MW load level, the 6,300 MW load model was scaled down in each control area uniformly by scaling the load growth down by a factor of 2/3 (4500/6300). The scaled down load totals for each control area are shown in Table 10.

Control area	Calculated 2020 load level (6300 MW)	Scaled load level (4500 MW)
Alliant Energy (West) (331)	3888.2	3711.1
Xcel Energy (North) (600)	12885.1	11960.5
Minnesota Power Co. (608)	1814.4	1727.1
Southern MN Municipal Power Agency (613)	442.4	410.4
Great River Energy (618)	3943.2	3627.8
Otter Tail Power (626)	2248.3	2085.9
Dairyland Power Co. (680)	1266.2	1177.6
Total	26487.8	24700.6

Table 10 – CapX 2020 Slow Area Growth

The generation total also was reduced by scaling each generator down by a factor of 2/3 (4500/6300). Table 11 shows the reduced generation totals for each generation bias scenario.

Slow Growth Analysis						
	North/West		**Minnesota**		**Eastern**	
	6300 MW	**4500 MW**	**6300 MW**	**4500 MW**	**6300 MW**	**4500 MW**
Northern Minnesota	1700	1214	1250	893	550	393
Dakotas	2100	1500	1000	714	1600	1143
Southern MN/ Northern Iowa	1875	1340	1875	1340	2125	1554
Metro	650	464	2200	1571	1000	714
Wisconsin	0	0	0	0	1000	714
Total	**6325**	**4518**	**6325**	**4518**	**6325**	**4518**

Table 11 – Slow Growth Generation Scenario

The results for each generation scenario at the slow growth load level will be discussed in detail in sections 5.1 – 5.3 of this report. The n-1 contingency output results tabulated in Appendices B-1 through B-3. For the slow growth n-1 analysis, the same contingencies from the anticipated growth study were run again and the transmission system was monitored in the following control areas:

Control Area	PSS/E Area #
Alliant Energy West	331
Xcel Energy	600
Minnesota Power Co.	608
Southern Minnesota Municipal Power Agency	613
Great River Energy	618
Otter Tail Power Company	626
Dairyland Power Company	680

5.1 Transmission Alternatives Considered for Slow Growth

For the slow growth sensitivity the CapX 2020 technical team began the analysis of each generation scenario with the facilities recommended for the 6300-MW vision study. The recommended facilities were individually removed to determine which of the facilities were also necessary at the 4,500 MW load/generation level.

For the Minnesota and North/West biases, the team determined that the majority of the facilities still were necessary even with the load reduced by 33 percent. For the eastern bias case at the slow growth level, there was less justification for some of the various recommended transmission lines. Although, higher voltage lines from the Wisconsin – Iowa border area towards the Twin Cities were still appropriate. It was also still clear that relief of existing facilities is needed on the system between the Dakotas and Minnesota. As explained in section 4.5, additional sensitivity work is still pending for the eastern bias case, both at the 6300 MW level and the slow growth scenario.

5.2 Minnesota Bias Scenario Slow Growth Results

5.2.1 Recommended Facilities

Ref. #	Data Source	Facility Name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton County	Granite Falls	345	110	82.5
F-11	MH	Benton County	Riverton	345	78	58.5
F-12	CAPX	Benton County	St. Boni	345	62	46.5

F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-17	CAPX	Boswell	Forbes	345	64	48
F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-32	CAPX	Forbes	Riverton	345	114	85.5
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
				Total	**1876**	**1407**

Table 12 – Slow Growth Load Level Minnesota Bias Recommended Facilities

Table 12 key:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

Diagram 13 – Slow Growth Load Level Minnesota Bias Recommended Facilities

5.2.2 Line Flows on Interface and Tie Lines

LINE	kV Voltage Level	Base 4500 MW FLOW (MW)	4500 MW UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	1351	1187	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1228	1224	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	180	184	Manitoba Hydro to northern Minnesota
Letellier – Drayton	230 kV	363	340	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	17	38	Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.)
Arrowhead – Stone Lake	345 kV	88	98	Duluth area to northwestern Wisconsin (then to Weston)

Eau Claire – Arpin	345 kV	206	146	West to central Wisconsin
Prairie Island – Byron	345 kV	169	227	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	260	197	Southeastern Minnesota – Eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	719	622	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	175	129	North of Sioux Falls, SD to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	220	128	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	302	272	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	317	297	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	250	220	Western Minnesota
Fargo – Moorhead	230 kV	54	64	Fargo, North Dakota to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	245	144	North Dakota, Minnesota border
Maple River – Winger	230 kV	75	55	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	137	78	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	209	136	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	91	80	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	227	156	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	1.2	34	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	194	165	Fargo area west into Minnesota
Genoa – Coulee	161 kV	268	206	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	288	188	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	281	183	Northern Minnesota

Table 13 – Slow Growth Minnesota Bias Tie Line/Interface Flows

5.3 North / West Scenario Slow Growth Results

5.3.1 Recommended Facilities

Ref. #	Data Source	Facility Name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton	Granite Falls	345	110	82.5

		County				
F-12	CAPX	Benton County	St. Boni	345	62	46.5
F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
			Total		**1620**	**1215**

Table 14 – Slow Growth Load Level North/West Bias Recommended Facilities

Table 14 key:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

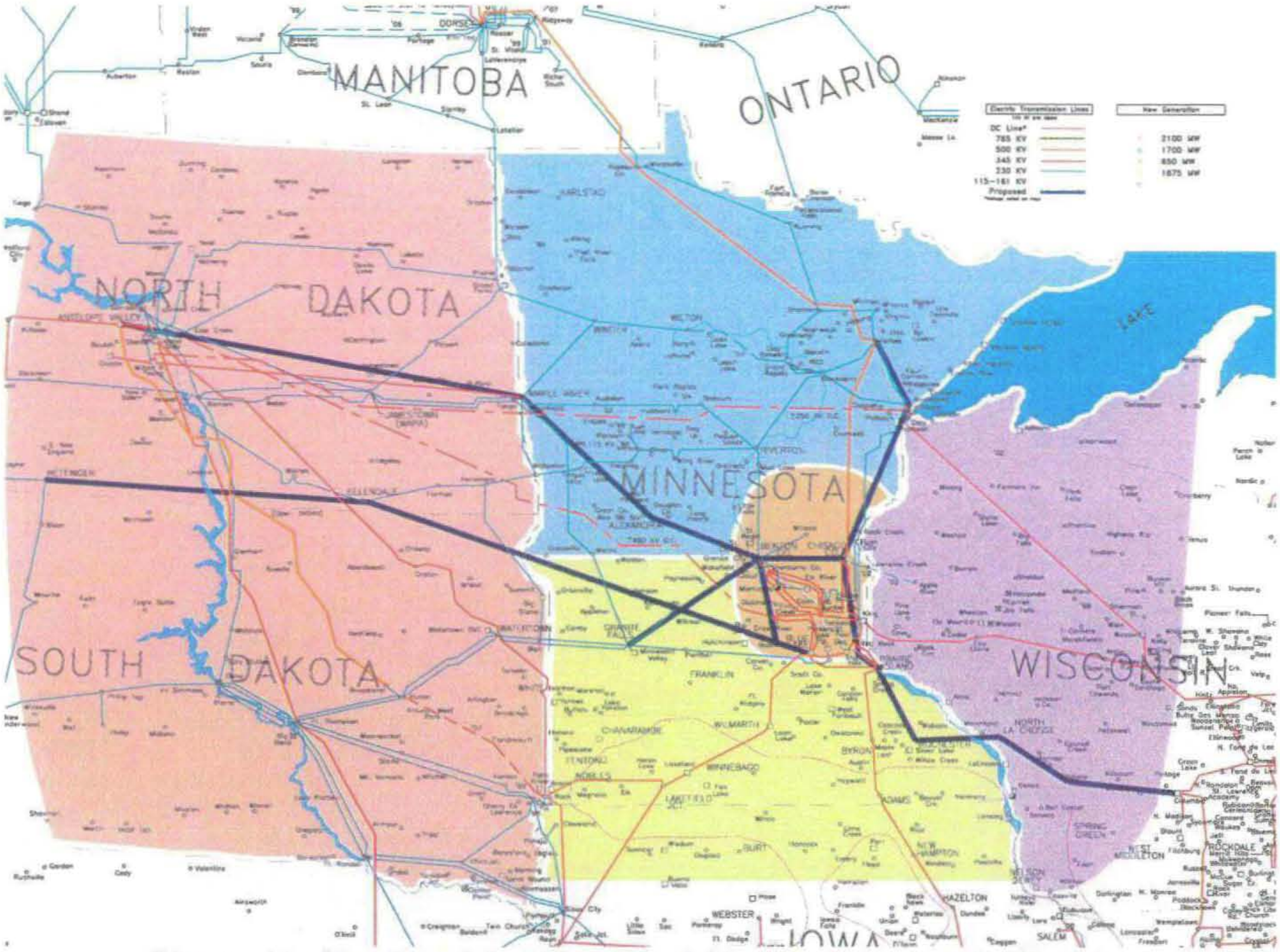

Diagram 14 – Slow Growth Load Level North/West Bias Recommended Facilities

5.3.2 Line Flows on Interface and Tie Lines

LINE	kV Voltage Level	Base 4500 MW FLOW	4500 MW UPGRADE scenario	Description
Forbes – Chisago	500 kV	1540.3	1398.6	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1842.1	1782.9	Manitoba Hydro to Northern Minnesota
Richer – Roseau	230 kV	228.5	223.5	Manitoba Hydro to Northern Minnesota
Letellier – Drayton	230 kV	392.3	405.6	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	34.1	81.1	Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.)

Arrowhead – Stone Lake	345 kV	298.3	310.9	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	72.3	57.8	West to central Wisconsin
Prairie Island – Byron	345 kV	165.4	185.3	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	173.9	92.9	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	746.1	602.3	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	263.9	184.4	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	336.4	252.5	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	248.5	232.0	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	279.8	270.1	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley tap	230 kV	375.4	288.3	Western Minnesota
Fargo – Moorhead	230 kV	54.5	55.4	Fargo, North Dakota, to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	271	200.7	North Dakota, Minnesota border
Maple River – Winger	230 kV	75.1	82.9	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	168.3	139.6	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	241.8	164.3	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	96.1	95.5	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	232.8	216.5	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	63.6	23.9	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	233.9	197.2	Fargo area west into Minnesota
Genoa – Coulee	161 kV	249.8	189.1	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	293.9	287.2	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	286.9	280.4	Northern Minnesota

Table 15 – Slow Growth North/West Bias Tie Line/Interface Flows

In the eastern bias scenario, the CapX 2020 technical team added part of the additional generation to the east of Minnesota (part on the border of northeastern Iowa and southwestern Wisconsin, part central Wisconsin), in addition to having generation throughout Minnesota, northern Iowa, North Dakota, and South Dakota as in the other two scenarios.

5.4 East Scenario Slow Growth Results

5.4.1 Recommended Facilities

Ref. #	Data Source	Facility Name From	To	Volt (kV)	Miles	Cost ($M)
F-56	SMNI	Prairie Island	Rochester	345	58	43.7
F-64	CAPX	Eau Claire	King	345	84	63.1
F-65	CAPX	N. LaCrosse	Eau Claire	345	73	55.1
F-66	CAPX	Genoa	N LaCrosse	345	42	31.7
F-67	CAPX	Genoa	Columbia	345	113	84.8
F-68	CAPX	Genoa	Nelson Dewey	345	70	52.4
F-69	SMNI	Nelson Dewey	Salem	345	34	25.6
F-70	CAPX	Genoa	Lansing	345	21	15.8
F-71	CAPX	Lansing	Rochester	345	89	66.8
F-72	CAPX	Ellendale	Big Stone	345	194	145.8
F-73	CAPX	Big Stone	Blue Lake	345	71	53.4
F-02	TIPS	Maple River	Benton Co	345	206	154.5
F-03	NW	Antelope Va.	Maple River	345	292	218.8
F-07	CapX	Arrowhead	Chisago	345	120	90
F-08	CapX	Arrowhead	Forbes	345	60	45
F-09	CapX	Benton Co	Chisago	345	59	44.2
F-10	CapX	Benton Co	Granite Falls	345	110	82.5
F-12	CapX	Benton Co	St Boni	345	62	46.5
F-26	CapX	Chisago Co	Prairie Island	345	82	61.5
F-30	NW	Ellendale	Hettinger	345	231	218.8
			Total		**2071**	**1,600**

Table 15– Eastern Bias Preliminary Recommended Facilities

Key for Table 15:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

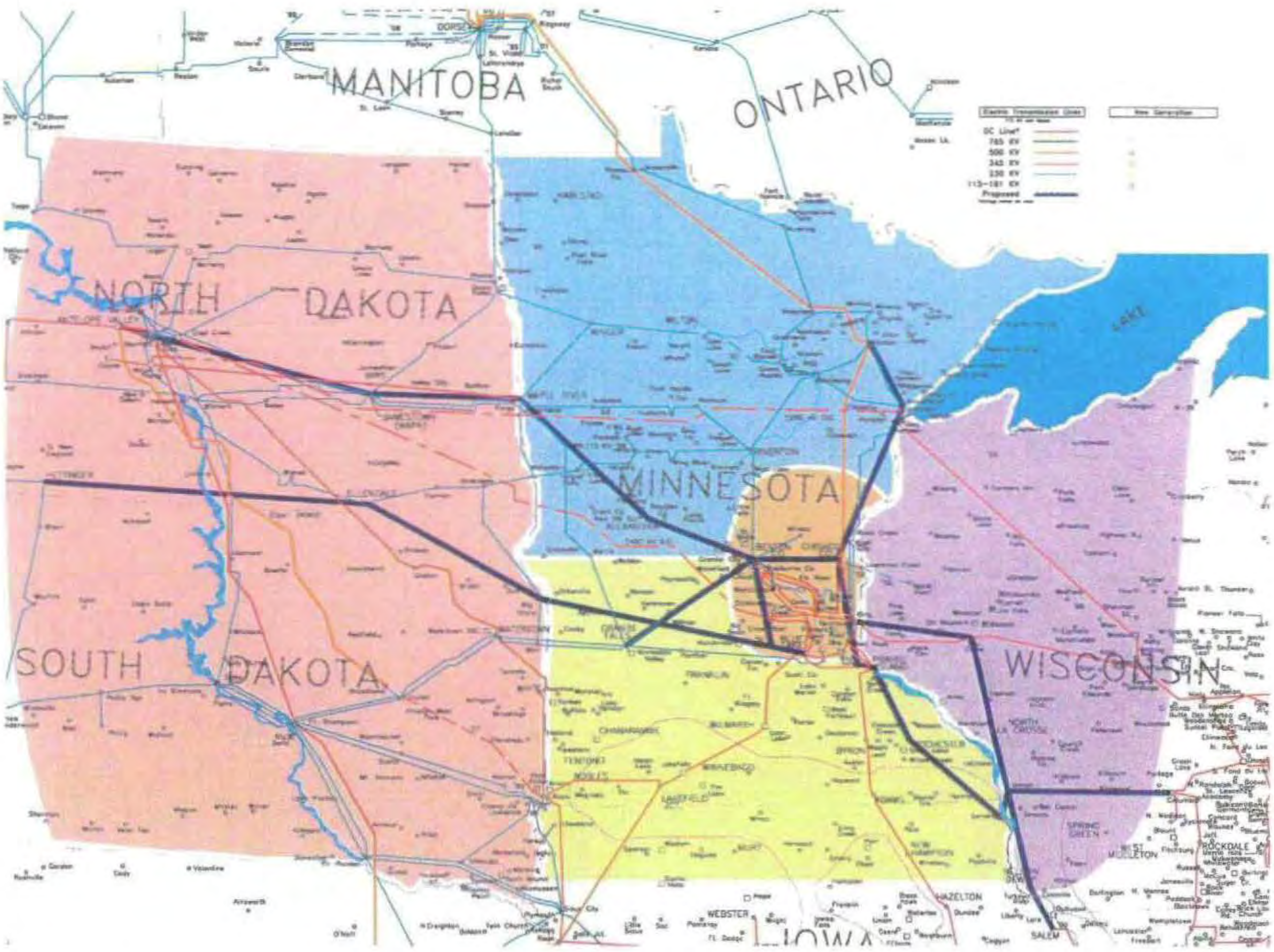

Diagram 15 – Eastern Bias Preliminary Recommended Facilities

6 Common Facilities

The CapX 2020 technical team's primary goal for this initial vision study was to identify a long-range transmission plan that would benefit Minnesota's electric reliability as load continues to grow over the next 15 years and beyond.

6.1 Common transmission alternatives between the Biases

The team found that the biases had 1620 miles of 345 kV transmission lines in common, for a total of \$1.215 billion.[5] For comparison, that is a little more than 80 percent of the cost of each scenario individually. The common facilities are shown in Table 18.

[5] When reviewing the results of this study, note that only the cost of transmission line per mile is represented. None of the associated substation, generation interconnection facilities, or underlying lower-voltage (below 161 kV) transmission system infrastructure costs are determined or included in this vision study.

Facility Name				
From	**To**	**Volt (kV)**	**Miles**	**Cost ($M)**
Alexandria	Benton County	345	80	60
Alexandria	Maple River	345	126	94.5
Antelope Valley	Jamestown	345	185	138.75
Arrowhead	Chisago	345	120	90
Arrowhead	Forbes	345	60	45
Benton County	Chisago County	345	59	44.25
Benton County	Granite Falls	345	110	82.5
Benton County	St. Boni	345	62	46.5
Blue Lake	Ellendale	345	200	150
Chisago County	Prairie Island	345	82	61.5
Columbia	North LaCrosse	345	80	60
Ellendale	Hettinger	345	231	173.25
Rochester	North LaCrosse	345	60	45
Jamestown	Maple River	345	107	80.25
Prairie Island	Rochester	345	58	43.5
	Total miles 1620	**Total cost $1,215 ($M)**		

Table 16 – Common Recommended Facilities

6.2 Additional transmission facilities for each scenario

In addition to the common facilities in the above table, the Minnesota bias had three additional unique facilities for a total of 256 miles and $192 million. These facilities are a result of the high concentration of generation in the St Paul/Minneapolis metro area.

The north/west bias also had three unique facilities for a total of 387 miles and $290 million. These facilities are a direct result of the 1000-MW import from Manitoba Hydro, which is included in the north/west generation bias.

The East Bias has unique facilities due to the difficulties sending power from the East to West across minimal river crossings.

7 Conclusion and Next Steps

The CapX 2020 technical team believes these results to be the cornerstone of future studies to better identify the transmission needs of the study region. These results need to be integrated into the MISO Transmission Expansion Plan and ongoing utility load-serving studies.

The team envisions future study efforts to incorporate the results of adjoining regional study efforts, investigate how the bulk transmission solutions can support the load-serving transmission, and investigate how the impacts of new load forecasts and generation interconnections impact the transmission vision. Additional studies to consider include:

- Scaling the 2009 model's load to a point where transmission violations begin to occur and determining which transmission alternative best solves the problem. The study should continue this effort to determine sequence and/or combinations of transmission additions.
- Analyzing the lower voltage system (below 161 kV) for voltage violations and thermal overloads during n-1 contingency analysis.
- Conducting detail studies (including stability analysis) to support a certificate of need for facilities identified as being critical to meet the needs of the transmission customer.
- Identifying bulk substation locations that address overloads on the load-serving transmission system and preparing least-cost planning alternatives that meet the anticipated load growth in the area. Studies would involve detailed load scaling efforts to better model local load growth. The team would review short-term alternatives to address immediate concerns such as switched capacitors, reconductoring, and voltage upgrades on existing corridors.
- Investigating impacts of alternative transmission technology (DC, FACTS, phase shifting transformers, etc.)
- Reconsidering alternative generation locations in each of the biases to determine the sensitivity of generation location on the transmission vision.
- Updating study results based on new generation interconnect/delivery study results.
- Integrating results of adjoining regional and MISO study efforts to determine impacts on transmission vision.

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Appendices

A. Composite List of Transmission Data

B. Tabulated Contingency Results, Load Flow Data and Automaps

B-1. MN Bias

- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

B-2. NW Bias

- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

B-3. Eastern Bias

- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

C. Transmission Characteristics and Cost Estimate Data

Appendix A
Composite List of Transmission Data – Recommended Facilities Include Facility Characteristics

Ref. #	Data Source	Facility Name: From Name	To Name	Volt (kV)	Miles	Cost ($M)	Facility Characteristics: From Bus #	To Bus #	R	X	Bch	Rating (MVA) Summer	
F-01	SMNI	Adams	Hayward	345	34	25.3							
F-02	TIPS	Alexandria	Benton County	345	80	59.9	67010	60142	.00299	.03276	.559	1165	
F-03	TIPS	Alexandria	Maple River	345	126	94.2	67010	66792	.00506	.05544	.946	1165	
F-04	CAPX	Alma	Rock Elm	345	60	45							
F-05	CAPX	Alma	Tremval	345	40	30							
F-06	NW	Antelope Valley	Maple River	345	292	219	67101	66792	.01058	.11592	1.978	1165	
F-07	CAPX	Arrowhead	Chisago	345	120	90	61608	60199	.00438	.04718	.80974	1303	
F-08	CAPX	Arrowhead	Forbes	345	60	45	61608	61622	.00191	.02060	.35357	1303	
F-09	CAPX	Benton County	Chisago County	345	59	43.9	60142	60199	.00269	.02890	.49602	1303	
F-10	CAPX	Benton County	Granite Falls	345	110	82.7	60142	66797	.00506	.05449	.93523	1303	
F-11	MH	Benton County	Riverton	500	78	58.5	61620	60142	.00361	.000494	.665	1303	
F-12	CAPX	Benton County	St. Boni	345	62	46.6	60142	62655	.00285	.03068	.52655	1303	
F-13	CAPX	Blue Lake	Ellendale	345	200	150	60192	99990	.014398	.157752	2.6918	1166	
F-14	NW	Blue Lake	Franklin	345	87	65.0							
F-15	NW	Blue Lake	Granite Falls	345	127	95.4							
F-16	CAPX	Blue Lake	West Faribault	345	50	37.5							
F-17	CAPX	Boswell	Forbes	345	64	47.7	61628	61622	.00292	.03142	.53926	1303	
F-18	TIPS	Boswell	Wilton County	230	72	54.3							
F-19	SMNI	Burt	Webster	345	50	37.3							
F-20	SMNI	Burt	Winnebago	345	56	41.9							
F-21	SMNI	Byron	Rochester	345	31	23.6							
F-22	SMNI	Byron	Wilmarth	345	72	54.2							
F-23	SMNI	White	Franklin	345	76	57.2							
F-24	SMNI	Chanarambie	White	345	53	39.8							
F-25	CAPX	Chisago County	King	345	52	39							
F-26	CAPX	Chisago County	Prairie Island	345	82	61.2	60199	60105	.00375	.04031	.69189	1303	
F-27	CAPX	Columbia	Genoa	345	110	83							
F-28	CAPX	Columbia	North LaCrosse	345	80	60	39157	92605	.00316	.04954	.5371	1328	
F-29	MH	Dorsey	Karlstad	345	134	100.5	67625	66750	.00383	.05688	.89380	1295	
F-30	NW	Ellendale	Hettinger	345	231	173.3	99990	67175	.0092	.1008	1.72	1165	
F-31	NW	Ellendale	Watertown	345	131	98.2							

F-32	CAPX	Forbes	Riverton	345	114	85.4	61622	61620	00522	.05622	.96491	1303	
F-33	CAPX	Franklin	Granite Falls	345	48	36							
F-34	CAPX	Franklin	Lyon County	345	70	52 5							
F-35	CAPX	Franklin	Wilmarth	345	60	45							
F-36	SMNI	Rochester	North LaCrosse	345	60	44 9	69999	92603	.00253	.02717	.46635	2110	
F-37	SMNI	Freemont	Rochester	345	0	0							
F-38	NW	Granite Falls	Watertown	345	93	69.9							
F-39	CAPX	Genoa	Lansing	345	0	0							
F-40	MH	Winger	Benton Co	345	162	121 5	66760	60142	.00735	.10920	1.7157	1295	
F-42	SMNI	Hayward	Winnebago	345	56	41 9							
F-43	SMNI	Hazelton	Salem	345	78	58 1							
F-44	NW	Jamestown	Maple River	345	107	80 4							
F-45	MH	Karlstad	Winger	345	91	114	66750	66803	.00311	.04623	.72631	1295	
F-46	CAPX	King	Rock Elm	345	50	37 5							
F-47	SMNI	Lakefield Junction	Winnebago	345	64	47.9							
F-48	CAPX	Lansing	Rochester	345	100	75							
F-49	CAPX	Lyon County	White	345	50	37.5							
F-50	SMNI	Nelson Dewey	Salem	345	35	25.9							
F-51	SMNI	Nelson Dewey	Spring Green	345	67	50.2							
F-52	SMNI	Nobles	Wilmarth	345	120	89.7							
F-54	SMNI	North LaCrosse	Spring Green	345	105	78.8							
F-55	CAPX	North Lacrosse	Tremval	345	55	41.3							
F-56	SMNI	Prairie Island	Rochester	345	58	43.7	60105	6999	.0046	.0494	.8479	2110	
F-57	MH	Riverton	Wilton County	500	96	72							
F-58	SMNI	Rockdale	West Middleton	345	36	26.7							
F-59	SMNI	Spring Green	West Middleton	345	31	23.2							
F-60	CAPX	West Faribault	Wilmarth	345	45	33 75							
F-61	MH	Wilton County	Winger	345	66	49.5							
F-62	CAPX	Wilmarth	Rochester	345	75	56 25							
F-63	CAPX	Lakefield Jct.	Adams	345	92	69	60331	60102	.00644	.06916	1.187	1303	
F-64	CAPX	Eau Claire	King	345	84	63.1							
F-65	CAPX	North LaCrosse	Eau Claire	345	73	55.1							
F-66	CAPX	Genoa	North LaCrosse	345	42	31.7							
F-67	CAPX	Genoa	Columbia	345	113	84.8							
F-68	CAPX	Genoa	Nelson Dewey	345	70	52.4							
F-69	SMNI	Nelson Dewey	Salem	345	34	25.6							

F-70	CAPX	Genoa	Lansing	345	21	15.8							
F-71	CAPX	Lansing	Rochester	345	89	66.8							
F-72	CAPX	Ellendale	Big Stone	345	194	145.8							
F-73	CAPX	Big Stone	Blue Lake	345	71	53.4							
				Total	**0**	**0**							

CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study

For the rest of the Appendices please refer to www.capx2020.com for the electronic version of the Technical Update report.

Attachment C

Xcel Energy Resource Plan Update
MPUC Docket E002/RP-10-825
December 1, 2011

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

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[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.

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[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.

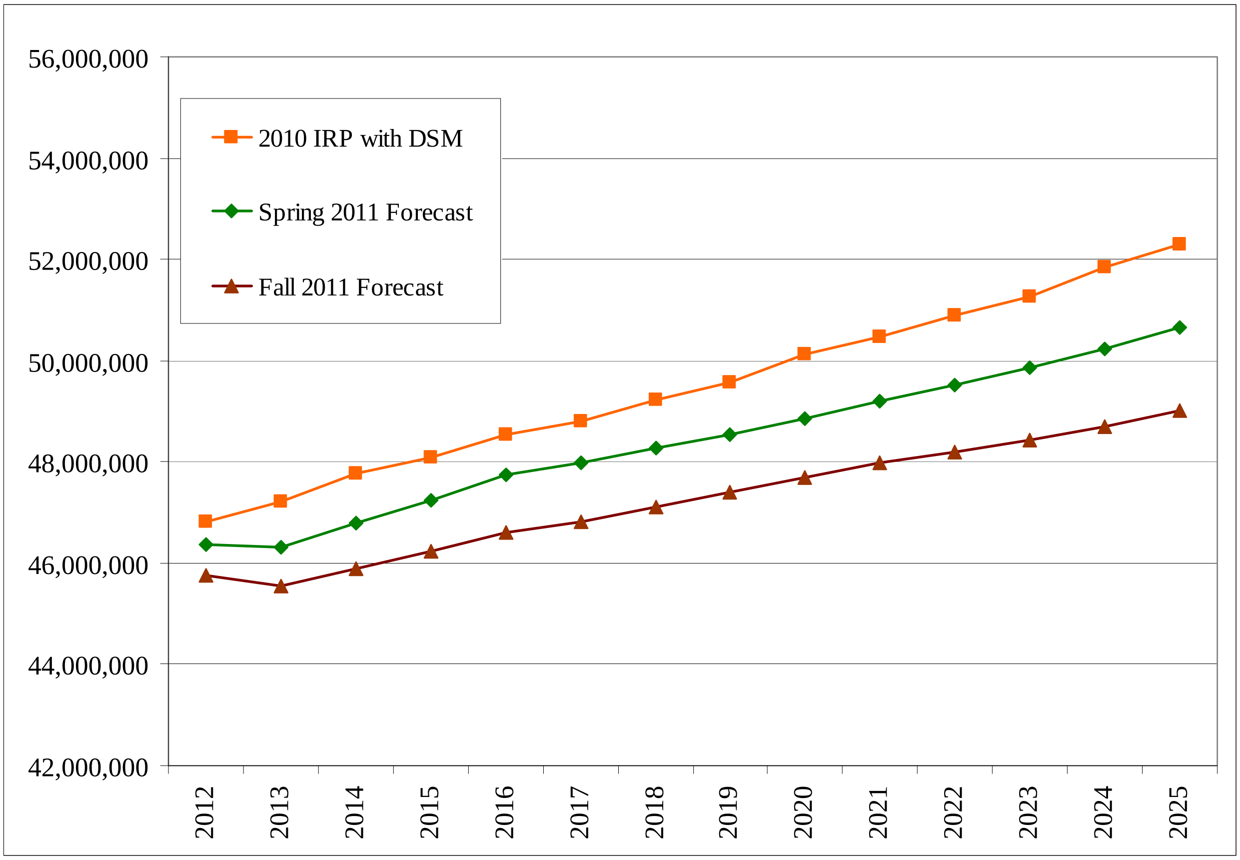
1. *Comparison of System Peak Demand and Median Net Energy Forecasts*

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

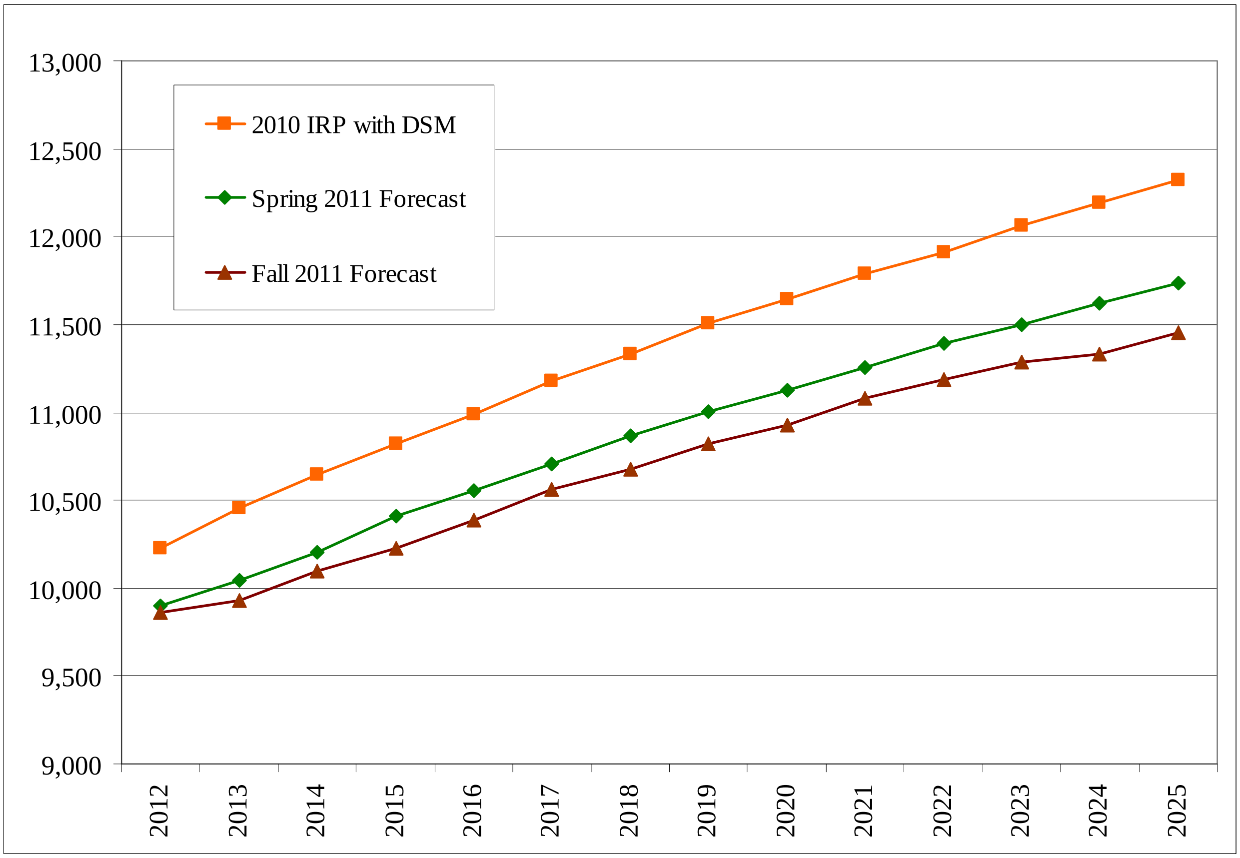
Forecast	**Annual Growth in System Peak Demand**	**Annual Growth in Median Net Energy**
Initial Resource Plan (June 2010)	1.1%	0.9%
Black Dog CON Update (June 2011)	0.9%	0.7%
Resource Plan Update (September 2011)	0.7%	0.5%

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



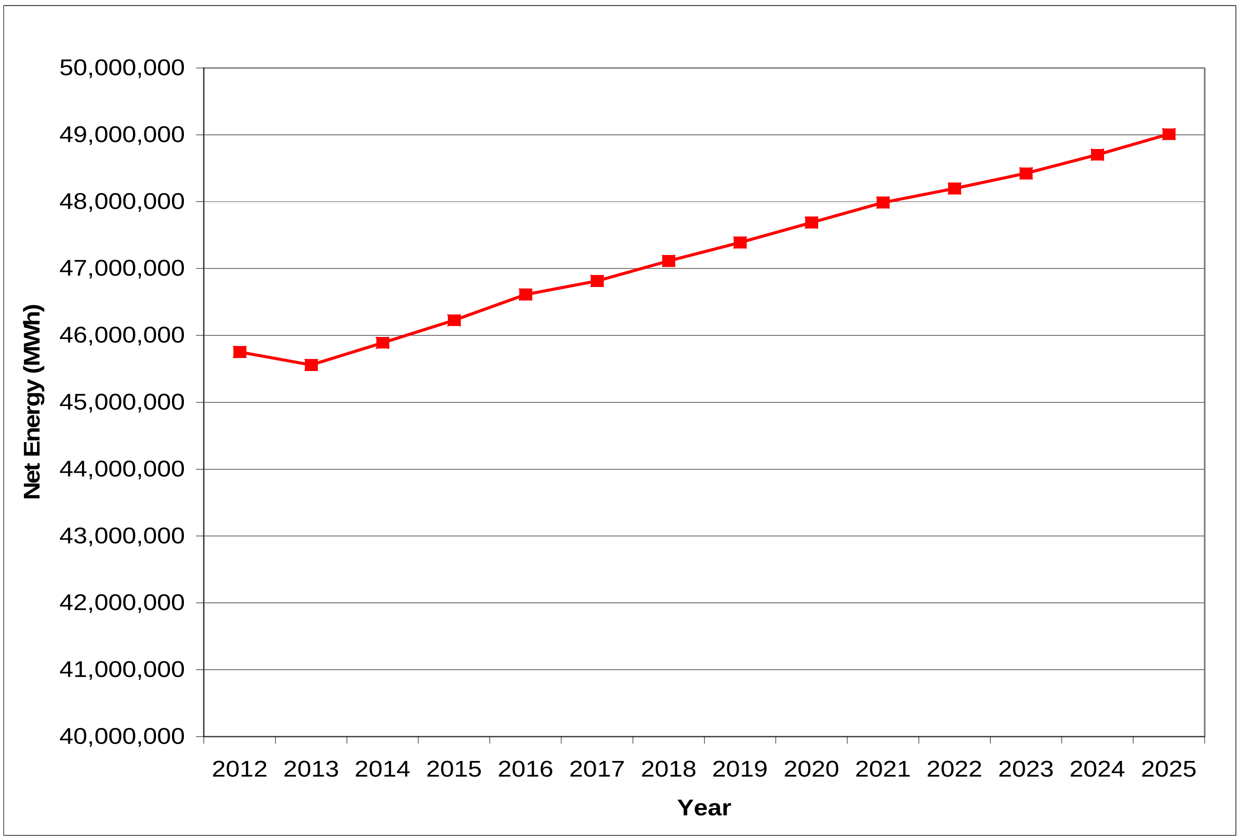
Revised Figure 3.7
Base Peak Demand (MW)
90th Percentile Forecast
Comparison of Current and Previous Demand Forecasts



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.

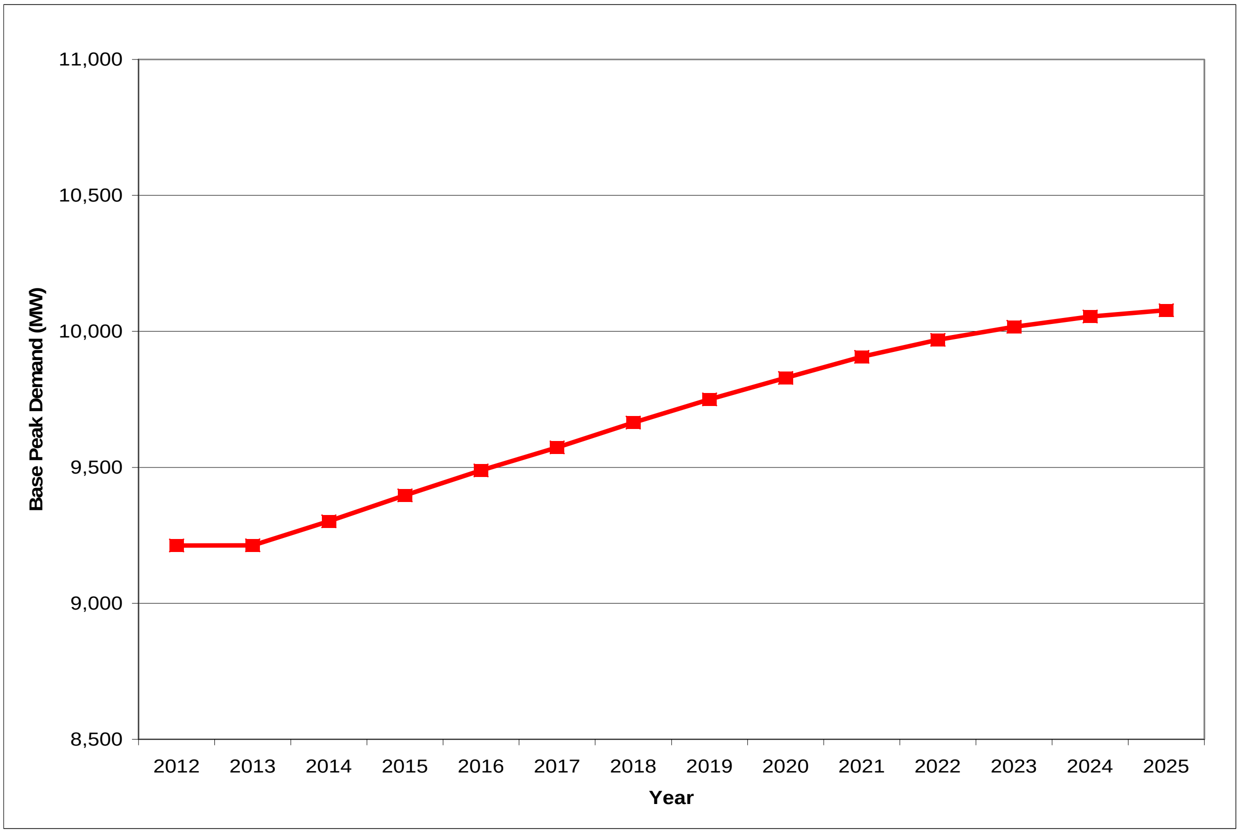
Revised Figure 3.1
Median Net Energy (MWh) NSP Total System
(Includes 1.5% Retail Sales DSM Adjustment)



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

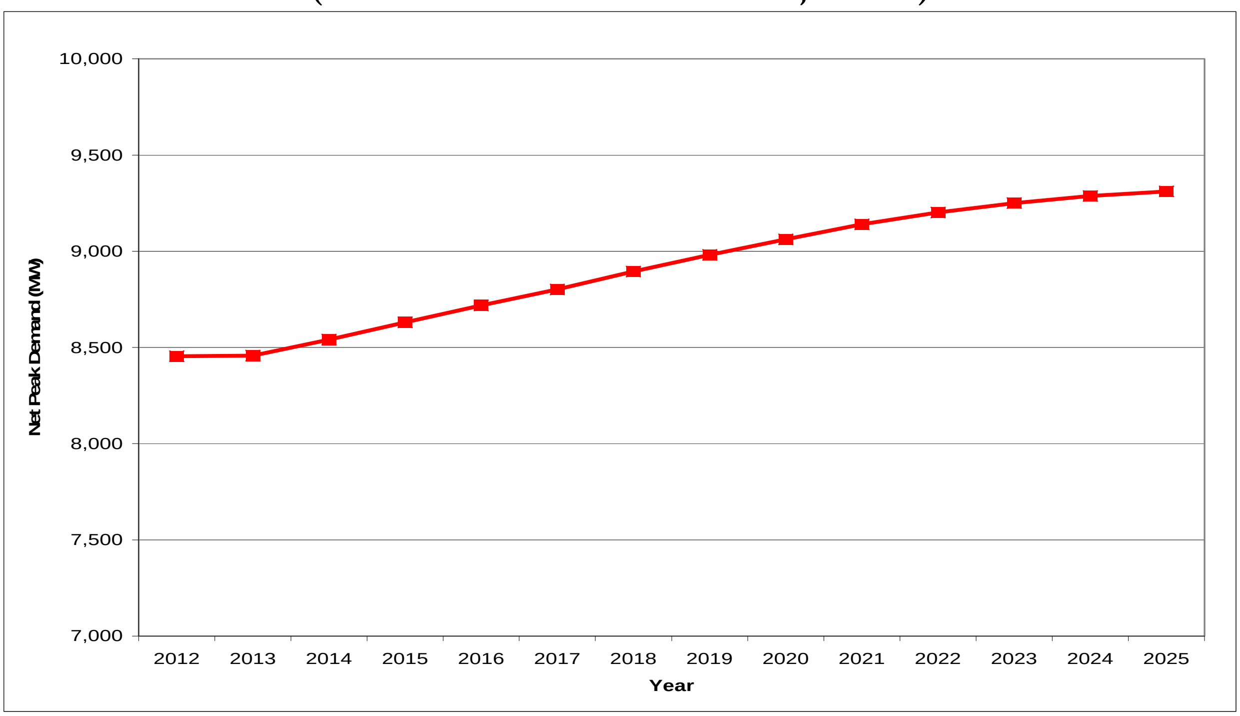
While many of the resources outlined in our initial Resource Plan are still needed, the discussion below explains our resource needs in light of our revised forecasts.

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*

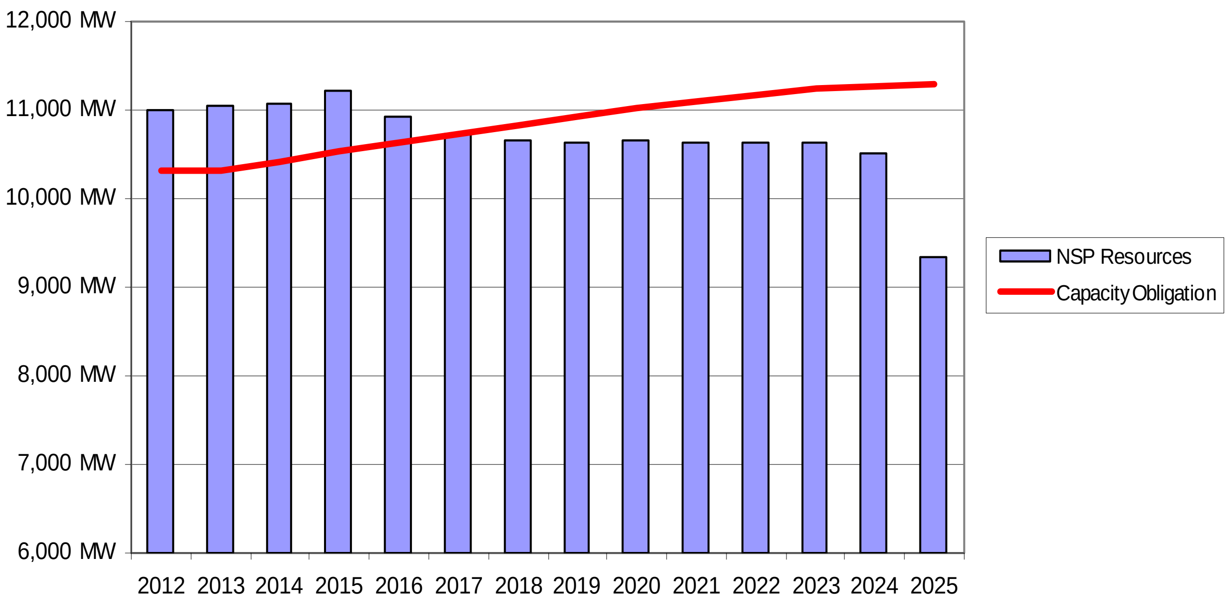
Based on our updated forecasted demand and expected available resources discussed above, we now anticipate new production capacity will be needed starting in 2018. This is three years later than indicated in our initial filing and provides us with additional time to assess the appropriate resources to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

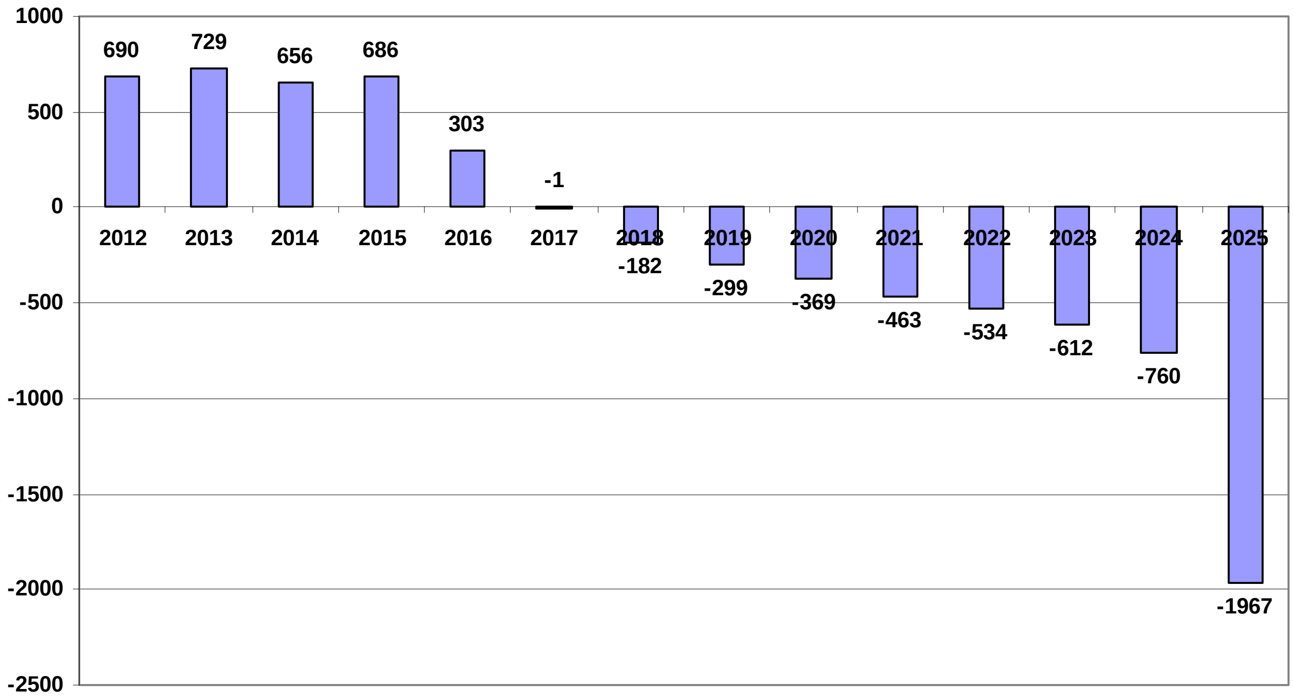
Revised Figure 3.10 presents an updated comparison of our forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions.

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.

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[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.

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[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	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	MH375500 125 MW	WIND_PPA 13 MW	WIND_PPA 13 MW		WIND_PPA 13 MW
		Sherco 3 8 MW	PrRose 26 MW		P Island 2 55 MW	P Island 1 55 MW				WIND_PPA 13 MW			WIND_PPA 13 MW		
		SAF Hydr 3 MW	ND_50 6 MW		MH375500 375 MW										
		NthShaok 0 MW	Monti 1 67 MW		DIV350IN 350 MW										
		GoodhuNS 10 MW	CrownHyd 1 MW												
		Fch Isld 3 61 MW	Borders 19 MW												
		DiamondK 0 MW													
		Danielsn 3 MW													
		CommWndN 4 MW													
		BigBlue 5 MW													
Resource Retirements	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
			Key City 4 -14 MW		MH500 -500 MW	Coyote 1 -100 MW	Rapidan -3 MW	Wilmarth 1 -18 MW	WSMorrn -6 MW	MNMethan -5 MW	Fch Isld 4 -64 MW	St.Cloud -7 MW	St Paul -25 MW	Fch Isld 1 -21 MW	Stahl -1 MW
			Key City 3 -14 MW		Div150In -168 MW		Div200In -224 MW	Viking -2 MW	WindPowr -3 MW		Fch Isld 3 -61 MW		MNDakota -19 MW	Chanaram -11 MW	MNWind -1 MW
			Key City 1 -14 MW					Red Wing 1 -20 MW	Moraine -7 MW		Byllesby -2 MW			Bayfront 6 -29 MW	MH375500 -500 MW
			Granite 4 -14 MW					HERC -34 MW	KODARAHR -12 MW					Bayfront 5 -22 MW	LkBnton2 -13 MW
			Granite 3 -14 MW					Flambeau 1 -14 MW						Bayfront 4 -19 MW	Inveneng 2 -161 MW
			Granite 2 -14 MW												Inveneng 1 -161 MW
			Granite 1 -13 MW												DIV350IN -350 MW

Thermal Units

	Capital Cost ($ millions)	Firm Capacity (MW)	Heat Rate (mmBtu/MWh)
Gas CT	$124	195	9.888
Gas CC	$671	729	6.713
Coal	$1,922	500	9.357
Coal w/CCS	$2,733	500	12.359

Renewable Resource

	Capital Cost	Nameplate (MW)	Capacity Credit	Capacity Factor	FOM ($000/yr)
Wind	$1,800	100	12.9%	40%	$2,000

Wind capital cost is converted to a PPA cost of $47.39 escalating at 2.36%

Attachment D

Staff Briefing Papers – Minnesota Public Utilities Commission
Meeting Date: February 20, 2013

Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: February 20, 2013 ....**Agenda Item **# 6**

Company: Xcel Energy (Xcel or the Company)

Docket No. **E002/RP-10-825**

In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan

Issues: With the additional modeling in the record, is Xcel Energy's 2011-2025 resource plan sufficient for planning purposes?

Should the Commission take any further actions in the resource plan?

Staff: Sean Stalpes 651-201-2252
Susan Mackenzie 201-2241

Relevant Documents

Xcel Resource Plan, Initial Filing .... August 2, 2010
Xcel Resource Plan Update ....December 1, 2011
MPUC Staff Briefing Papers for the October 25, 2012 Agenda Meeting .... October 18, 2012
Commission Order, In the Matter of Xcel's Resource Plan... November 30, 2012
Xcel Energy Comments ....December 18, 2012
Department of Commerce Comments ....December 18, 2012
Calpine Reply Comments ....January 16, 2013
Department of Commerce Reply Comments..January 18, 2013
Xcel Energy Reply Comments ....January 22, 2013
Environmental Intervenors Corrected Reply Comments..January 23, 2013

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

This document can be made available in alternative formats (i.e., large print or audio) by calling (651) 296-0406 (voice). Persons with hearing or speech disabilities may call us through Minnesota Relay at 1-800-627-3529 or by dialing 711.

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Background

Xcel's 2011-2025 resource plan was filed on August 2, 2010. Since the initial filing, several developments contributed to Xcel modifying its action plan:

- On March 15, 2011, Xcel filed a petition for a certificate of need for its Black Dog Generating Plant Repowering Project. At the time, Xcel anticipated the project would address a projected generation deficit starting in 2014.

- On December 1, 2011, Xcel filed its Update to the Resource Plan, which included new energy and demand forecasts. Xcel's updated forecasts, which revised growth downward, and loss of wholesale customers were principal factors that changed the start of Xcel's capacity deficit to 2017.

- In the Company's 2011 Update to the IRP, Xcel stated its intention to withdraw its request for the Black Dog certificate of need. On May 30, 2012, Administrative Law Judge Richard C. Luis certified to the Commission Xcel's motion to withdraw its Black Dog certificate of need application.

- On April 2, 2012, Xcel filed a Notice of Changed Circumstances (NoCC) and Petition for a delay in implementation and change in capacity (size) of the extended power uprate (EPU) at the Prairie Island Nuclear Generating Plant. Xcel stated that changes to load forecasts, costs of alternative resource options, and uncertainties now possible in the federal licensing process reduced the potential benefits associated with the EPU. However, at the time the NoCC and Petition were filed, the EPU was "still expected to benefit customers."

- Intervening parties, including the Department, filed comments on June 12, 2012 (almost two years after the initial IRP filing). Citing reasons including time "to review Xcel's new forecast," "the number of IRPs, certificates of need, and rate cases," and time to "coordinate analysis of the resource plan with Xcel's Black Dog repowering project," the Department needed to file eight extension requests to prepare its comments.

- On October 22, 2012, Xcel effectively withdrew its Petition to pursue an EPU at Prairie Island, which Xcel anticipated would provide an additional 117 MW of capability starting in 2016.[1]

To evaluate the effects of removing 117 MW of baseload from the five-year action plan, DOC requested 30 days to re-run the Strategist model. At the Commission's request, Xcel agreed to model these new circumstances as well.

Pursuant to the Commission's November 21, 2012 Order in the competitive resource acquisition docket (CN-12-1240), Xcel filed a proposed notice plan to potential providers of generation, stating that Xcel "has a significant need for new generation before 2020." The Commission approved the notice plan on January 30, 2013, and Xcel filed its publication of the approved notice on February 8, 2013.

[1] Docket Nos. E002/CN-08-509; E002/RP-10-825; E002/CN-11-184

On February 4, 2013, Xcel filed a letter of intent to issue a Request for Proposals (RFP) to procure up to 200 MW of wind generation. According to Xcel:

> "With the extension of the federal renewable electricity production tax credit (PTC) effective January 2, 2013, we believe it is prudent to assess opportunities for additional wind resources on our system at this time to determine if there are cost-effective wind projects that could provide long-term value to our customers."

Xcel expects to issue the wind RFP as soon as February 15, 2013; the PTC extension carries a requirement for wind projects to begin construction by the end of 2013. Xcel outlines a projected timeline for the RFP process, which indicates a "Decision Report" will be filed in July 2013.

Since Xcel has "enough renewable energy credits to meet RES compliance requirements through 2020," by issuing the RFP, Xcel is not "committing to add wind generation if no projects provide reasonable benefits over the long term."

Oral Argument, October 25, 2012 Agenda Meeting

Xcel's resource plan docket was before the Commission in two consecutive weeks, the first of which was Oral Argument on October 25, 2012. At Oral Argument, members of the public and intervening parties addressed the Commission regarding Xcel's resource plan. This document summarizes the comments during Oral Argument from the intervening parties: Xcel Energy, the Department of Commerce, the Minnesota Chamber of Commerce, the Environmental Intervenors, and Calpine Corporation.

<u>Xcel</u>

Xcel identified several areas of consensus around issues raised in the docket.

1. Xcel has reached agreement with DOC on what the appropriate demand and energy forecasts should be, at least for planning purposes.

2. For the most part, intervening parties agree on the size and timing of generation that should be added to the system, except for whether removing the Prairie Island EPU affects that range.

3. Even to the issue of type of generation, there is some consensus that Xcel should be seeking a natural gas-fired dispatchable resource, which does not preclude further development of renewables.

4. Xcel agrees with many of the public comments and the recommendation of the Environmental Intervenors that further evaluation of the Company's remaining coal, particularly Sherco 1 and 2, would be beneficial. Xcel supported developing a Sherco Life Cycle Management Study.

5. Regarding wind additions, Xcel agrees with many of the parties' comments to consider further wind in the event the federal wind production tax credit is renewed and how it affects the marketplace. Xcel believes there is time to consider wind additions between the instant resource plan and the subsequent one.

Thus, Xcel concluded "the central question is resource acquisition and how to structure a process around that." There may be a dispute with the Department about the right mix of intermediate and peaking capacity, but Xcel emphasized that there seems to be consensus about the range of capacity needed, and the time for it to be acquired. Xcel believes that the 400-600 MW recommended by the Department is a reasonable range, and the Commission could close the resource planning docket and initiate the resource acquisition process to procure the Company's need.

The difference between Xcel and the Department's approach, from Xcel's view, is how much specificity needs to go into the process. Xcel stated that the Commission could determine how much "type" (combined cycle versus combustion turbine) would be needed, but Xcel's preference is "providing the process with some flexibility so actual proposals could be compared and contrasted rather resource planning assumptions to date."

Xcel explained that, when the Company looks at the operation of its system in 2017-2019, the resources to be added likely will not operate many hours. Thus, a combustion turbine peaking resource may meet that need most cost-effectively. According to Xcel, "on a generic basis," a combustion turbine has about half the capital cost of, but higher operating costs than, a combined cycle facility. These cost considerations are beneficial if the system needs are such that a resource may only be needed for a relatively small amount of hours.

Over the last several years, Xcel has invested in more than 1,000 MW of combined cycle capacity (i.e., roughly 500 MW at High Bridge and 500 MW at Riverside). According to Xcel, "the capacity factor of those two plants today is roughly 20 percent."

Xcel's Strategist modeling configured the units to operate at 30 percent into 2018. Thus, according to the Company, "there is a huge amount of available production capacity on [Xcel's] system" if the High Bridge and Riverside facilities were to operate at the 30 percent assumed in Strategist. Moreover, "they can operate at 70-80 percent," so Xcel does not believe another combined cycle addition benefits the system at this time.

To the question of Xcel conducting its own modeling of removing the Prairie Island EPU from the five-year action plan, Xcel agreed it could benefit the Commission's decision. However, Xcel noted that "when it comes to combined cycle versus combustion turbines," it is possible that the modeling will result in a similar conclusion than what the Company proposed at Oral Argument.

Xcel argued the 400-600 MW range could likely accommodate both situations of the EPU moving forward, or not. If the Commission agrees with a procedural schedule for competitive acquisition, Xcel would investigate this range further, take further comment, and then make a decision on the effect removing the Prairie Island EPU would have on resource acquisition.

Department of Commerce

The Department of Commerce (Department, or DOC) noted that Xcel's October 22, 2012 filing, which clarified the Company's position that it would not move forward with the Prairie Island EPU, was based on the same forecast applied to Xcel's December 2011 Update, the action plan of which included the EPU.

If Xcel does not pursue the EPU, removing 117 MW of uprate capability from means adding to a need projected to be 552 MW by 2020 *with the uprate*. Therefore, DOC emphasized that Xcel has a large need, and "time is of the essence" to add resources to meet that need.

Before Xcel filed its letter on October 22, 2012, DOC noted the modeling seemed to be clear that Strategist selected either a combined cycle unit or a combustion turbine *with wind*, suggesting that Xcel would ultimately need energy as well as capacity. With the October 22, 2012 change in circumstances, DOC proposed to the Commission that it would be useful to model the impacts of removing the EPU.

The Department also pointed to several of the changes to the record, highlighted on page 3 of this document, which has continued to jumble what is actually needed. DOC noted their analysis has continued to show Xcel's need for baseload, which was initially consistent with Xcel's modeling in the Company's Black Dog certificate of need proceeding.

Therefore, one reason why the Department believes it is important for the Commission to find Xcel needs "400-600 MW of something" is because the process may get completely bogged down again. Particularly given Xcel's withdrawal of its Prairie Island EPU, which explicitly was premised on a need for more baseload, the Department did not agree with Xcel's new position that no baseload would be needed prior to 2020.

DOC made no recommendation to approve the resource plan, and instead concluded more information is needed to approve the overall plan.

<u>Chamber of Commerce</u>

The Chamber of Commerce (Chamber) stated their overall concern is that Xcel has cost-effective rates, recognizing the Company also needs to be environmentally sound. The Chamber argued that the State of Minnesota as a whole has been dropping in competitiveness in its rates, thereby losing the opportunity to attract new business, or even keep existing businesses.

The Chamber also expressed concern that Strategist is not accurately or adequately capturing the realities of the costs of resource plans, which is explained it further detail in the October 18, 2012 Staff briefing papers.

The Chamber agreed with the decision option requiring Xcel to consider more demand response. According to the Chamber, "Simply including Xcel to take action on demand response in a resource plan does not mean that it will be implemented in rate cases. Ultimately, Xcel's ability to utilize more demand response can only be expanded through rates."

<u>Environmental Intervenors</u>

The Environmental Intervenors (EIs) stated, that while the conversation centered mostly on short-term actions, the EIs discussed "longer-term decisions," which is one of the reasons IRP exists.

The EIs argued there is a legal issue before the Commission, which is a statutory requirement for a utility, like Xcel, to provide a least-cost scenario that supplies 50 percent and 75 percent of refurbished and new capacity with renewables and conservation.[2]

The “longer-term” function of a resource plan should require Xcel to look both at its new capacity needed over the 15-year time horizon, and how much refurbishment the utility will need, in order to develop the 50/75 scenarios. According to the EIs, Xcel did not include the refurbishment portion of the statutory requirement. Specifically, Sherco 1 and 2 will require substantial modification, yet the 50/75 scenarios were not modeled as a potential replacement.

The EIs did not request the Commission order Xcel to model this scenario as a compliance filing in the instant resource plan docket. Instead, the EIs recommended Xcel be required to develop a Sherco Life Cycle Management Study and include the 50/75 percent scenarios in the Company’s 2014 IRP.

The EIs agreed with Xcel’s proposal to retire Black Dog 3 and 4 as a coal-fired resource by 2015. However, the EIs requested that, since the issue is so important, the Commission find in its Order that Black Dog cannot cost-effectively operate on coal beyond 2015.

Calpine

Calpine agreed with Xcel’s comments that trade-offs exist between capital costs and operating costs. Calpine noted that what Xcel assumes for the capacity factor of its existing resources in not an issue in which Calpine is involved because Calpine did not conduct Strategist modeling to prepare their comments. However, Calpine did raise the point that, if a utility can procure a combined cycle facility at a reasonable cost, it is a “higher value project” for customers in the long-run.

Still, Calpine agreed with Xcel and the Department that a combination of both combined cycle and peaking facilities is probably needed at some point. This combination, though, can be done on a phased-in basis, and a peaking project can be developed which subsequently can be converted to combined cycle cost-effectively.

Xcel Energy Comments

Commission Order Point #1 states:[3]

“With respect to the current docket, the Commission establishes the following procedural schedule:

- December 18, 2012: Deadline to file comments. The Department and Xcel shall file any final revisions to their models and analysis.
- January 16, 2013: Deadline to file reply comments.
- February 2013: Commission action and docket closure.”

[2] Staff note: A list of Relevant Statutes to resource plan is included in ***Attachment C*** of this document.
[3] The Commission’s November 30, 2012 Order in the resource plan is included as ***Attachment A*** of this document.

Xcel filed its comments on December 18, 2012. Xcel recommends the Commission's Order:

1. Make a finding on size and timing only. Xcel recommends the Commission set the need at 154 MW in 2017, 319 MW in 2018, and 443 MW in 2019.

2. Make no finding on the specification of the resource type. Instead, Xcel recommends letting the competitive resource acquisition process identify the most cost-effective proposals.

3. Provide participants in the competitive resource acquisition process the flexibility to offer peaking or intermediate resources or a combination of the two, as well as the flexibility to address all or a portion of the identified need;

4. Allow proposals in the competitive resource acquisition process from existing generators; and

5. Take no action at this time to reduce the estimated resource need based on potential demand response benchmarking.

Xcel will be bidding in its own proposal, which consists of three combustion turbine (CT) units, to meet the 2017-2019 resource need specified in the Commission order. Xcel requests the competitive resource acquisition process be flexible to allow "all or portions of" Xcel's proposal to be considered in combination with other projects.

Xcel's Strategist modeling "selects a combination of combustion turbines and combined cycle power plants as the most cost-effective resource additions" during the planning period. However, "the model does not readily distinguish between the cost effectiveness of the combustion turbine and combined cycle additions in the 2017 to 2019 timeframe."[4]

Because the modeling provides mixed results, Xcel recommends the competitive resource acquisition process ultimately determine the least-cost plan. This will allow detailed cost and operating characteristics of actual proposals to determine the "type" of Xcel's next resource addition.

1. *Xcel recommends the Commission make a size and timing finding only.*

Xcel recommends the Commission's Order specify the estimated generation deficits by year "to provide project developers with specific guidance regarding the size and timing of [Xcel's] resource needs."

Xcel's modeling discussed in its December 18, 2012 filing identifies a capacity deficit of:
- 154 MW in 2017;
- 319 MW in 2018; and
- 443 MW in 2019.

Thus, Xcel's recommendation is for the Commission to make a size and timing finding which includes these exact values. Specifying the amount of capacity need, and the years in which the need exists,

[4] Xcel Energy December 18, 2012 comments, p. 6.

would set the parameters of the competitive resource acquisition process such that developers know what to bid.

Xcel's resource need (size and timing) "continues to be based on the median peak demand forecast presented in [Xcel's] December 2011 Resource Plan Update filing with the adjustments recommended by the Department in their June 2012 Comments." Xcel discusses the following adjustments made to the model since that forecast was developed for the 2011 Update:

- An updated reserve generation margin based on MISO's unforced capacity (UCAP) methodology;
- Removal of the 117 MW that was anticipated with the completion of the Prairie Island Extended Power Uprate (EPU);
- Continued operation of Xcel's Key City peaking facility (43 MW) and Granite City peaking facility (54 MW) until 2016;[5] and
- Bringing back to service French Island Unit 3 (57 MW) starting in 2016 and continuing its operation throughout the planning period.

Xcel requests the Commission take no action at this time regarding demand response. According to Xcel's comments:

> "Through existing tariffs, including our interruptible service and Savers Switch programs, the Company can currently reduce demand during peak periods by approximately 1,000 MW."

Xcel responds to the Environmental Intervenors recommendation for Xcel to pursue an additional 300 MW of demand response, and, accordingly, reduce the size determination by that amount. The Environmental Intervenors recommendation is based on a DSM Potential Study conducted by KEMA Consulting, which states Xcel can cost-effectively incorporate about 300 MW of demand response under business-as-usual conditions.

Xcel does not believe the demand response study cited by the Environmental Intervenors is specific enough to Xcel's service territory, nor is it "developed sufficiently to establish additional programs to deliver a firm demand reduction."

Therefore, Xcel recommends the Commission not to reduce the estimated resource need, or to modify the parameters of the competitive resource acquisition process, based on demand response capability identified by KEMA's DSM potential study.

2. *Xcel requests the Commission make no finding on resource type.*

Xcel requests that the Commission "not predetermine what mix of peaking and intermediate generation best meets the identified need." Instead of a Commission finding on "type," Xcel recommends the

[5] The Key City and Granite City units reached the end of their depreciable lives in 2012.

Commission allow the competitive resource acquisition process identify the most cost-effective proposals.

According to Xcel:

> "The type of generation selected does not affect the size or timing of the resource need. Instead, the type of generator added to the system affects the overall dispatch and operation of the fleet of generators and cost of electricity."[6,7]

Table 1 below shows Xcel's Strategist results under base case conditions. Under the baseline assumptions, Strategist selected one intermediate unit and one peaking unit between 2017 and 2019 in the least cost plan.

An alternative action plan consisting only of peaking units (the "All Peaking" case) is "estimated to have an additional $16 million in present value of revenue requirements (PVRR)."

Table 1
Base Case Strategist Results

	Size & Timing	At Least 1/2 Intermediate	All Peaking
2015	157		
2016	32		
2017	(154)	Intermediate(354MW)	Peaking(189MW)
2018	(319)		Peaking(189MW)
2019	(443)	Peaking(189MW)	Peaking(189MW)
2020	(532)		
2021	(612)	Peaking(189MW)	Intermediate(354MW)
2022	(694)		
2023	(795)	Peaking(189MW)	
2024	(904)		
2025	(2077)	Peaking(189MW) & Interm x3(1062MW)	Peaking(189MW) & Interm x3(1062MW)
2026	(2120)		
PVRR $millions		$34,462	$34,478
Difference			$16

Xcel's sensitivity analysis, provided in Table 2 below, shows that several factors can influence the PVRR of the "All Peaking" case:

[6] Xcel Energy's December 18, 2012 comments, p. 5.
[7] Staff note: This modeling result is different than that of the Department. DOC's modeling indicates that the total amount of capacity added depends on the mix of intermediate versus peaking capacity.

Table 2
Strategist Sensitivity Results

PVRR ($millions)	At Least 1/2 Intermediate	All Peaking	Difference	*Change from Base*
Base Assumptions	$34,462	$34,478	$16	
Low Gas	$33,419	$33,435	$16	*$0*
High Gas	$35,439	$35,456	$17	*$1*
$0 CO2	$29,526	$29,538	$12	*($5)*
RES Wind	$34,798	$34,807	$9	*($7)*
Markets On	$33,545	$33,542	($3)	*($19)*
CTs -15%	$34,403	$34,408	$4	*($12)*
CTs + 15%	$34,520	$34,548	$28	*$12*
CC - 15%	$34,324	$34,354	$30	*$13*
CC +15%	$34,600	$34,602	$3	*($13)*

Xcel's sensitivity analysis explains, in part, the importance of their recommendation that the Commission make no finding on type. Strategist suggests that different input assumptions, in addition to how the resources interact with Xcel's system overall, can impact whether intermediate or peaking capacity is preferred.

Xcel discusses two important resource alternatives, wind and market energy, which carry uncertainties, but can also result in benefits for Xcel's customers. As shown in Table 2, wind and market energy shrink the cost difference between the "1/2 Intermediate, 1/2 Peaking" plan and the "All Peaking" plan.

According to Xcel, "the base case was designed without the addition of any new wind generation beyond what is current on the system and under contract." Xcel's "RES Wind" scenario (see Table 2) forced an additional 1,200 MW of wind generation (in 200 MW increments every other year starting in 2014), in order to meet the Company's RES obligations.

Additional wind energy on Xcel's system would result in other generating units operating less frequently, thereby reducing the value of an intermediate unit addition. However, the Company notes that "the cost-effectiveness of additional wind acquisitions will depend heavily on federal tax policy decisions regardless of peaking or intermediate generating additions."

Xcel's modeling also shows that "when the Strategist model is allowed to purchase energy from the MISO market, peaking resources look more cost-effective than adding a combined cycle plant." In Xcel's "Markets On" sensitivity, the "All Peaking" case was least-cost.

In the competitive resource acquisition process, Xcel's proposal will consist of three combustion turbine units to meet the resource need in the 2017- 2019 timeframe. Xcel requests the Commission make no finding on the mix of intermediate versus peaking capacity at this time, and instead allow the resource acquisition process to determine the least-cost proposal which optimally interacts with the operating characteristics of Xcel's overall system.

Strategist modeling is based on generic units, and Xcel notes that the cost and performance data from actual projects will differ from Strategist. According to Xcel, the preliminary estimates of the peaking units Xcel will be proposing are at a cost "lower than the generics used in resource plan modeling." "Likewise, a developer proposing an intermediate resource may be able to offer a project below the cost of the generic unit modeled in Strategist."

3. Parameters of the Resource Acquisition Process

Xcel recommends the Commission make an explicit finding to allow proposals from existing generators bid into the competitive resource acquisition process (i.e., to allow Xcel to bid in its own generation or to negotiate a supply agreement with another utility's existing generation).

Xcel also believes that the competitive resource acquisition should be flexible enough to allow bids of peaking or intermediate resources, or a combination of the two, as well as the flexibility to address all or a portion of the identified need.

Party Positions

Department of Commerce Comments

The Department of Commerce (the Department, or DOC) recommends that the Commission:

"Require Xcel to pursue up to 500 MW of natural gas fired (peaking and intermediate) capacity for implementation in the 2017 to 2019 time frame. The specific type of capacity should be determined based upon actual bids submitted in Xcel's approved competitive resource acquisition process."

The Department concludes that it is necessary for the Commission to determine the specific size, type, and timing of resource additions, and this determination is central to the resource planning process.

Minnesota Rules for integrated resource plans require the utility to provide an action plan. Specifically, Minn. Rules 7843.0400 subpart 3 C states:

> "The supporting information must include an action plan, a description of the activities the utility intends to undertake to develop or obtain noncurrent resources identified in its proposed plan. The action plan must cover a five-year period beginning with the filing date. The action plan must include a schedule of key activities, including construction and regulatory filings."

While DOC recommends the Commission determine that the specific 500 MW added in 2017-2019 be natural gas-fired, the competitive bidding process should ultimately resolve the specific type of natural gas.

The Department is clear that, since the modeling provides mixed results as to whether the natural gas additions be intermediate or peaking, actual data from bids is a better way to determine "type" than through modeling of generic resources.

The Department's comments focus on resource additions in the 2017 to 2019 timeframe because "planning for the acquisition of these resources is required now."[8] Moreover, the purpose of DOC's comments is to "ascertain the impact on the Company's least-cost expansion plan of not pursuing an uprate at the Prairie Island nuclear generating plant."

Resource Additions

Table 1 below shows the size, type and timing of the least-cost expansion plan under base case assumptions.[9]

Table 1: Department Base Case Expansion Plan

	Annual Accredited Capacity Added			
	CT	CC	Baseload	Wind
2012	-	-	-	-
2013	-	-	-	-
2014	-	-	-	-
2015	-	-	-	-
2016	-	-	-	-
2017	-	303	-	-
2018	-	-	-	-
2019	189	-	-	-
2020	-	-	-	26[5]
2021	-	-	-	-
2022	189	-	-	-
2023	-	-	-	-
2024	189	-	-	26
2025	189	908	-	-
2026	-	-	-	-

The least-cost expansion plan in Strategist adds about 500 MW of natural gas in 2017-2019, most of which is a combined cycle facility.

As with other resource plans, the Department makes its recommendations by evaluating trends among broad ranges of scenarios and contingencies, so it is not necessarily the case that the least-cost expansion plan becomes DOC's recommendation.

Among the most cost-effective plans, DOC finds two distinct plans in the 2017-2019 timeframe, and both represent characteristics of an intermediate resource:

1. ***The "CT plus wind" plan*** – Two combustion turbine (CT or peaking) units totaling 378 MW, usually accompanied by a 200 MW wind unit. (DOC also refers to this plan as the "two CT plan.")

[8] DOC comments, p. 6.

[9] As shown in Table 1, 200 MW of nameplate wind capacity translates into 26 MW of accredited capacity by assuming a wind capacity credit of 13 percent.

2. ***The "CT plus CC" plan*** (shown above in Table 1) – One CT unit and one combined cycle (CC or intermediate) unit. Typically, no wind units are added between 2017 and 2019 in the "CT plus CC" plan.

The Department discusses the ten least cost plans Strategist ranked. According to DOC's analysis, the "CC plus CT" plan is included in seven of the ten plans with the lowest cost. The "CT plus wind" plan is included in the other three of the ten plans with the lowest cost.

Stated another way, the ten least cost plans Strategist selects exhibit the characteristics of intermediate capacity.

Intermediate versus Peaking Needs

Types of supply-side resources evaluated by the Department include peaking, intermediate, baseload, and wind. DOC defines an intermediate plant in their comments as a combined cycle, natural gas-fired plant. However, the Department notes that gas-fired combustion turbines and wind together ("CT plus wind") can be combined to provide the characteristics of an intermediate plant.

Because the ten least cost plans include a path which chooses a combined cycle gas facility (the "CC plus CT" plan) and a path that does not choose a combined cycle gas facility ("CT plus wind" plan), the Department recommends that both intermediate and peaking be pursued in the competitive acquisition process. This recommendation, however, does not mean DOC's analysis is unclear as to whether Xcel has an energy need. The action plans which select gas combustion turbines are almost always accompanied by wind or other energy sources.

Thus, the Department defines "intermediate" facilities as gas-fired combined cycle facilities or a peaking unit plus something else to supply energy. Under base case conditions, only two contingencies do not observe the "CT plus wind" or "CT plus CC" rule: CO_2 reduction and wholesale market available.

Modeling results

DOC evaluated four scenarios in its modeling, each with 36 contingencies. In addition to the base case (i.e., the "No EPU" scenario), the Department ran scenarios that included:

- removing all CO_2 pricing ("No EPU, No CO_2" scenario);
- forcing wind units to comply with the renewable energy standard ("No EPU, Wind Mandate" scenario); and
- forcing an additional 100 MW of load management ("No EPU, 100 MW DSM" scenario)

Table 2 below presents the scenarios' expansion plans in terms of cumulative natural gas additions (peaking and intermediate) in 2017-2019. The vast majority of contingencies in all four scenarios add 378 MW of combustion turbines (i.e. two 189 MW combustion turbines) or 492 MW of peaking and intermediate capacity (i.e. one 189 MW combustion turbine and one 303 MW CC unit).

Table 2: Total Peaking and Intermediate Plant Added, 2017-2019 (MW)

Total Gas MW	No EPU	No EPU No CO_2	No EPU Wind Mandate	No EPU 100 MW DSM
Base Case	492	492	492	378
$34 CO_2	378	492	378	378
$9 CO_2	492	492	492	378
CO_2 Delayed	492	492	492	378
CO_2 Reduction	492	492	492	303
High Capital Cost +10%	492	567	492	378
Low Capital Cost -10%	378	492	378	378
Low Externalities	492	492	492	378
Coal - 20%	492	492	492	378
Coal - 10%	492	492	492	378
Coal + 10%	378	492	492	378
Coal + 20%	378	492	378	378
Natural Gas - $1.50	492	567	492	378
Natural Gas - $1.00	492	492	492	378
Natural Gas - $0.50	492	492	492	378
Natural Gas + $0.50	378	492	378	378
Natural Gas + $1.00	378	492	378	378
Natural Gas + $1.50	378	492	378	378
Natural Gas + $2.00	378	492	492	378
Natural Gas + $2.50	378	492	492	303
Natural Gas No Growth	591	567	591	402
Wholesale Market On	378	378	378	189
$35 Wind	378	378	492	303
$40 Wind	378	378	378	378
$45 Wind	378	378	378	378
$50 Wind	378	378	378	378
$55 Wind	378	492	378	378
$60 Wind	378	492	378	378
$70 Wind	492	492	492	303
$75 Wind	492	492	492	303
$80 Wind	492	492	492	303
Wind High Credit (20%)	492	492	492	378
Wind Low Credit (10%)	492	492	492	378
Forecast, Mid-High	303	303	378	492
Forecast, High	567	567	567	303
Minus 15 Pct CT CC	492	492	492	378

Strategist consistently adds the following combinations of total peaking and intermediate capacity in the 2017 to 2019 timeframe:

- 492 MW of intermediate and peaking natural gas-fired capacity; one combustion turbine (of 189 MW in size) and one combined cycle unit (of 303 MW in size), as shown in Table 1; or
- 378 MW of peaking facilities (two CT plan) plus 200 MW of wind.[10]

Of note, the mid-high forecast contingency actually adds less capacity between 2017 and 2019 than the base case forecast. This outcome occurs because the peaking unit added under the base case forecast is accelerated to 2016.

When wholesale market purchases are allowed, three of the four scenarios add two peaking units (379 MW in total). However, when the wholesale market is allowed, *and 100 MW of DSM is forced into the model*, only one combustion turbine is added (189 MW in total). The wholesale market availability contingency in the 100 MW DSM scenario is the only model run in which less than 300 MW of natural gas capacity is added in 2017-2019.

[10] Using a 13 percent wind capacity credit, 200 MW of wind represents 26 MW of accredited capacity.

Capacity "Type" is Highly Sensitive to Modeling Assumptions

Table 2 above shows that Strategist selects a common size and timing of the capacity to add (i.e. either the "CT plus wind" plan or the "CC plus CC" plan). However, "the specific resource plan it chooses to provide the intermediate plant is sensitive to the input assumptions."

DOC's base case analysis indicates a slight preference for Xcel to procure an intermediate CC unit in 2017 and a peaking CT unit in 2019. However, as shown in Table 3 below, this result depends largely on the contingency.

Table 3: Total Combined Cycle Capacity Added, 2016-2019 (MW)

Total CC MW	No EPU	No EPU No CO_2	No EPU Wind Mandate	No EPU 100 MW DSM
Base Case	303	303	303	-
\$34 CO_2	-	303	-	-
\$9 CO_2	303	303	303	-
CO_2 Delayed	303	303	303	-
CO_2 Reduction	303	303	303	303
High Capital Cost +10%	303	-	303	-
Low Capital Cost -10%	-	303	-	-
Low Externalities	303	303	303	-
Coal - 20%	303	303	303	-
Coal - 10%	303	303	303	-
Coal + 10%	-	303	303	-
Coal + 20%	-	303	-	-
Natural Gas - \$1.50	303	-	303	-
Natural Gas - \$1.00	303	303	303	-
Natural Gas - \$0.50	303	303	303	-
Natural Gas + \$0.50	-	303	-	-
Natural Gas + \$1.00	-	303	-	-
Natural Gas + \$1.50	-	303	-	-
Natural Gas + \$2.00	-	303	303	-
Natural Gas + \$2.50	-	303	303	303
Natural Gas No Growth	402	-	402	402
Wholesale Market On	-	-	-	-
\$35 Wind	-	-	303	303
\$40 Wind	-	-	-	-
\$45 Wind	-	-	-	-
\$50 Wind	-	-	-	-
\$55 Wind	-	303	-	-
\$60 Wind	-	303	-	-
\$70 Wind	303	303	303	303
\$75 Wind	303	303	303	303
\$80 Wind	303	303	303	303
Wind High Credit (20%)	303	303	303	-
Wind Low Credit (10%)	303	303	303	-
Forecast, Mid-High	303	303	-	303
Forecast, High	-	-	-	303
Minus 15 Pct CT CC	303	303	303	-

Findings from DOC's comments explain, in much greater detail than in this document, why certain contingencies added a combined cycle unit, and why others did not. Basically, though, some of the results show that:

- The 100 MW DSM scenario typically does not add any combined cycle (intermediate) capacity. Table 3 shows that, unlike the other three scenarios, forcing 100 MW of DSM generally adds only peaking capacity.

- The Department assumed a wind cost of $65 per MWh in the base case. If wind is priced higher than $65 per MWh, combined cycle is added. If wind is priced below, combined cycle is not added, and, instead, the "CT plus wind" plan is preferred.

- No combined cycle capacity is added in the "Wholesale Market On" contingency.

- When CO_2 costs are removed, combined cycle capacity is added in most contingencies.

Because Strategist is highly sensitive to the modeling assumptions, the modeling provides no overwhelming preference for the "CT plus wind" or "CC plus CC" plan. Therefore, DOC recommends the Commission make no finding on the appropriate mix of combined cycle versus combustion turbine natural gas capacity.

Assumptions / Modeling Inputs

The Department discusses their modeling assumptions and changes to Xcel's baseline assumptions on pages 4-5 of their comments.

The Department's modeling started with the same model that was used for their June 12, 2012 comments in this docket. Then, DOC modified some of the inputs to make a new base case.

According to Attachment A, Page 1 of Xcel's 2011 Update to the Resource Plan, Xcel assumed to retire the 43 MW Key City peaking plant and the 54 MW Granite City peaking plant in 2012 because these units were at the end of their depreciable lives. Based on discussions with Xcel, the Department (and Xcel) deferred the retirement date of the two facilities from 2012 to 2016.[11]

The 57 MW French Island 3 peaking unit was brought back on-line in 2014 and maintained on-line through Xcel's resource plan period—also based upon discussions with Xcel.[12]

DOC implemented the midpoint of the Commission-approved range of CO_2 values beginning in 2017 (i.e. DOC's base case CO_2 value is $21.50/ton starting in 2017).

The Department assumed a wind cost of $65 per MWh in the base case. "[D]ue to the scheduled expiration of the federal wind production tax credit on December 31, 2012" (an assumption made before its one-year renewal), DOC believes $65 per MWh is reasonable for planning purposes.

[11] The depreciable life of Xcel's Key City plant in Mankato (43 MW) and Granite City plant near St Cloud (54 MW) expired at the end of 2012. However, Xcel has no immediate plans to retire these units from operation, and Xcel believes their age and condition is such that they can continue to operate through 2016.

[12] French Island Unit 3 developed a short circuit in 2009 and has been unavailable for dispatch since that time. Since the NSP system has had excess capacity since 2009, Xcel has not yet invested the capital to repair the unit. Xcel examined the cost of repair and currently estimates the facility can be brought back to service with an approximate $3 million investment. Xcel believes this is a cost-effective way to maintain peaking generating capacity, and Xcel's updated model includes the 57 MW at French Island Unit 3 starting in 2016 and continuing for through the planning period.

Calpine Reply Comments

Calpine supports the Department's recommendation of establishing a need of approximately 500 MW of natural gas capacity in the 2017 to 2019 timeframe and agrees that the competitive resource acquisition process should solicit proposals for both peaking and intermediate resources.

Calpine agrees with both Xcel and the Department that the process should be flexible enough to allow developers to bid projects to meet all or part of Xcel's resource need.

Calpine opposes Xcel's recommendation that the Commission specify Xcel's projected capacity deficits by year. According to Calpine, Xcel's recommendation would be counterproductive to prospective bidders, not beneficial.

Calpine argues that Xcel's recommendation for the Commission to set exact capacity deficits by year "would effectively bias the process toward Xcel's own proposed project." Nothing in the Department's modeling suggests that three equal capacity additions represent the least-cost approach under any of its modeling scenarios. In effect, Xcel's recommendation would "unnecessarily restrict the range of proposals."

Moreover, Calpine believes Xcel's recommendation is inherently inconsistent with the resource planning process. By its nature, resource planning is imprecise, and demand growth does not always increase incrementally, such as how the assumptions are built into Strategist.

In Calpine's view, the Commission should not be overly specific with respect to the type of project(s), and instead, let the competitive resource acquisition process itself determine the least-cost proposal to best suit Xcel's needs.

Calpine also discusses several procedural issues in both their resource plan comments and the certificate of need docket (Docket No. 12-1240). Because these procedural issues will be discussed in detail, and included as decision options, in the certificate of need docket, Staff does not include these procedural issues as IRP decision options.

Calpine recommends the following guidelines to be adopted in the competitive resource acquisition process, which are included as decision options in the CN docket, but not in the IRP docket:

- The Department should serve as an independent evaluator within the context of a contested case hearing;

- The Commission and the Department should consider the assistance of an experienced third-party evaluator with relevant expertise in managing this type of competitive procurement process;

- The Commission should require Xcel to submit a fixed price bid rather than a traditional cost-of-service bid if it wants to participate in this competitive procurement process

Environmental Intervenors Reply Comments

The Environmental Intervenors (EIs) consist of the Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and the Minnesota Center for Environmental Advocacy. The EIs' comments were prepared with technical assistance from Sommer Energy, LLC.

The Environmental Intervenors recommend the Commission:

A. Find that it is premature to initiate a competitive resource acquisition proceeding at this time. Instead, the following actions should be taken:

    a. Require Xcel to begin immediately and complete within 9 months a thorough demand response potential evaluation that can be relied on in forecasting future need.

    b. Incorporate the evaluation of Xcel's capacity needs over the 2017 to 2019 timeframe into the existing Sherco study.

    c. Require Xcel and the Department to use the most recent forecast data available in their analyses of Xcel's capacity needs.

    d. Direct Xcel and the Department to make available to the Strategist model other resources, including market purchases, distributed generation resources, and additional DSM.

B. If the Commission determines to move forward with the competitive resource acquisition proceeding:

    a. Xcel has the burden to demonstrate in the contested case proceeding that it has the stated capacity need, and that the need cannot be met more cost-effectively through DSM or renewable resources.

    b. Flexibility for participants to offer all types of resources, including supply-side and distributed generation resources, as well as flexibility to address all or a portion of the identified need.

1. Xcel's demand forecast is outdated.

The comments filed by Xcel and the Department, and their respective recommendations concerning the size and timing of Xcel's resource need, are predicated on the December 2011 Update.

According to the EIs, Xcel employees have disclosed "that at least one new load forecast" has been developed since the model used for the December 18, 2012 comments. This forecast "was materially different from the forecast produced in Fall 2011, noting that the more recent load forecast shows a greater decline in demand."[13]

[13] Environmental Intervenors January 23, 2013 comments, p. 2.

Xcel's recently filed Rate Case provides further evidence of declining demand and indicates the previous forecast (used for the modeling before the Commission in the instant IRP docket) overestimated demand growth. Xcel witness Jack Dybalski stated in recently filed testimony before this Commission that "[o]ur sales forecasts have, for the last five years, failed to accurately predict the slow customer growth and declining sales we have experienced."[14] In addition, Xcel's witness in the Rate Case stated that "we [Xcel] believe that even if the economic recovery gained momentum, the changes in how our customers use energy would dampen sales into the future, making a significant near-term rebound in sales very unlikely."[15]

According to the EIs:

> "[O]ne of the tenets of good resource planning is that the best available information be used. In this case, that means Xcel and DOC should be using the most recent load forecast in their model runs."

The EIs recommend the Commission "defer any decision regarding Xcel's capacity needs in the 2017-2019 timeframe to the Sherco study Xcel is currently undertaking." This would allow Xcel to include more recent forecast data into its overall resource planning strategy.

2. *The Commission should require Xcel to complete a demand response potential study before commencing the competitive acquisition proceeding.*

A 2012 Xcel-commissioned DSM potential study conducted by KEMA concluded that nearly 300 additional MW of demand response is available by 2020 to Xcel, if it expanded upon its current programs. The amount is even greater in scenarios that assume additional investments and technology advances.

According to the KEMA study:

> "Total DR potentials by 2020 increase from 941 MW in the BAU case to 1,209 MW in the Expanded BAU case, to 1,444 MW in the Achievable Potential case, to 1,552 MW in the Full Participation case. Potential reductions could increase from 12 percent of system peak in the BAU scenario up to 20 percent of system peak in the Full Participation scenario if these types of capacity reductions were needed on the Xcel Energy system."[16]

The EIs argue that Xcel's reasoning (stated on page 7 of this document) for "disregarding the KEMA study's conclusions" are not justified.[17] Nevertheless, the EIs asked Xcel what would be required in order to rely on additional demand response, and the Company responded, "primary research with its customer base. Such a study would take up to nine months and cost approximately $225,000."[18]

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[14] In the Matter of Northern States Power Company's Application for Authority to Increase Electric Rates in Minnesota, Docket No. E002/GR-12-961, Direct Testimony and Schedules, Jack S. Dybalski at 3 (November 2, 2012).
[15] Id., p. 4.
[16] Xcel Energy Minnesota DSM Market Potential Assessment, Final Report—Volume 1, (KEMA, April 22, 2012) p. 6-3.
[17] Environmental Intervenors January 23, 2013 comments, p. 5.
[18] Xcel Response to MCEA IR No. 93, Exhibit B.

Since the forecast Xcel is using for its modeling is outdated, the Company's most recent forecast shows its previous forecast overestimates its demand, and Xcel refuses to rely on the conclusions of a demand response study the Company itself commissioned, the EIs recommend:

> "The Commission should delay the start of a competitive procurement proceeding until Xcel has completed the study it says would be required to know the amount of demand response available on its system."

3. *The modeling does not demonstrate there is a need for up to 500 MW of natural gas-fired capacity in the 2017-2019 timeframe.*

The EIs conclude that—to the extent the forecast data are reliable—Xcel's future needs are for capacity resources, not energy resources. In the event future energy needs exist, Xcel can meet these with exist resources, which runs at very low capacity factors.[19]

The EIs argue that Strategist was "effectively forced to choose gas-fired capacity in formulating a least-cost plan" in both Xcel's and DOC's modeling. Moreover, the Department's modeling unreasonably restricts MISO in the model, given that Xcel has historically made "significant purchases from MISO."

4. *If the Commission moves forward with the competitive procurement proceeding, it should make clear that Xcel must still demonstrate its need cannot be more cost-effectively met through DSM or renewables.*

Minn. Stat. § 216B.243, subd. 3.(Certificate of Need for Large Energy Facility) states:

> "No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need."

If the Commission determines the competitive resource acquisition process may continue, the EIs request the Commission state in its Order that "OAH resolve the issue of whether the projected need is justified, consistent with the Certificate of Need statute."[20]

Staff Analysis

It is important to recall why the decisions to defer approval of the resource plan and to pursue additional modeling were made in the first place. Page 7 of the November 30, 2012 Commission Order regarding Xcel's resource plan states:

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[19] Staff note: During Oral Argument on October 25, 2012, Xcel stated their Riverside and High Bridge plants run at about a 20% capacity factor, and these facilities therefore have much more production capability.
[20] Environmental Intervenors January 23, 2013 comments, p. 15.

> "Xcel concludes that between 2017 and 2019 it will need to add 400-600 MW of generating capacity – **and perhaps more**,[21] to offset the capacity that Xcel no longer proposes to add to its Prairie Island Plant.
>
> Parties offer various recommendations about **whether the Commission should approve, reject, or modify Xcel's resource plan**,[22] including its five-year action plan. The Department, among others, argues that the parties have not had sufficient opportunity to review the multiple changes Xcel has filed. The Department argues, and Xcel agrees, that the Commission's judgment would benefit from additional analysis."

On October 22, 2012, Xcel effectively withdrew its Petition to pursue an extended power uprate (EPU) at the Prairie Island Nuclear Generating Plant.[23] To evaluate the effects of removing 117 MW of baseload from the five-year action plan, DOC requested additional time to re-run the Strategist model. At the Commission's request, Xcel agreed to model these new circumstances as well.

Thus, the purpose of the extra time allocated for the modeling serves to ensure Xcel's five-year action plan is sufficiently robust to "approve, reject, or modify" it, as stated in the Commission Order.[24] To this end, the Commission could decide that the record is now sufficient for planning purposes by approving the resource plan and closing the docket. Since the competitive resource acquisition process already has an established schedule, and since there is near consensus among Xcel, the Department, and Calpine regarding the <u>size and timing</u> (not completely on type) of Xcel's next resource addition, the Commission is not required to make further findings. (See Minn. Rule 7843.0500, Commission Review of Resource Plans, and Minn Stat. § 216B.2422, Subd. 2., Resource Planning, included in ***Attachment B*** of this document.)

The Commission can adopt the following, which is included in the Decision Options:

- *Decision Option #1:* Approve Xcel Energy's 2011-2025 resource plan for planning purposes only. This finding of approval does not extend to particular generation projects that will be subject to review under future proceedings, but is a general finding that the plans filed by Xcel appear to be sufficient for planning purposes.

<u>Establishing Parameters for the Resource Acquisition Process</u>

Although the Commission is not required to set the parameters of the resource acquisition process, Staff agrees with the Department's analysis on page 3 of their comments that an additional finding by the Commission would be useful:

> "In order for the action plan to be clearly understood (e.g., construct what kind of project? Make what sort of regulatory filings?), the utilities' actions must be detailed enough so that disputes do not arise regarding what steps are to be taken. In most recent resource plans the Department concluded that it is necessary for the Commission

[21] Emphasis added.
[22] Emphasis added.
[23] Docket Nos. E002/CN-08-509; E002/RP-10-825; E002/CN-11-184
[24] Minn. Stat § 216B.2422, Subd. 2. (Resource Planning) states, "The commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest."

> to determine the specific size, type, and timing of resource additions, thus determining an action plan that is understandable by all parties. Such a Commission determination also ensures that future resource acquisition proceedings (certificates of need and power purchase agreement reviews) have a specific enough target so that they can be concluded in a timely manner and so that system reliability is maintained in a least cost manner. The Department continues to conclude that one of the main purposes of resource planning is the determination of the size, type and timing of resource additions."

The Commission could take a step beyond approving the resource plan and the previously made requirements for the next resource plan (including the Sherco Life Cycle Management study) by making a size, type, and timing finding. This additional finding would establish the parameters of the resource acquisition process and inform prospective bidders what Xcel needs.

Xcel's resource acquisition notice plan, which was approved by the Commission on January 30, 2013, simply announces the initiation of the competitive resource acquisition process. The Company was ordered to "refine the guidance" to prospective bidders in response to Commission action in the resource plan.[25] A Commission size, type, and timing finding, as the Department states, ensures the resource acquisition process has a specific enough target. However, this target does not mean the Commission is determining, via the resource plan, exactly what Xcel's next resource addition will be.

<u>A size, type, and timing finding only *informs* resource acquisition; it does not finalize it.</u>

Xcel requested the Commission's size, type, and timing determination in the resource plan initiate and inform a competitive resource acquisition process to solicit bids to procure the Company's needs.

During Deliberation at the November 1, 2012 Commission meeting, the Department outlined the differences between the scope of the resource plan and the scope of the resource acquisition process. DOC noted, "The resource plan sets size, type, and timing, and 'type' means whether it baseload or peaking. It does not determine fuel source."

"We [the Department] probably expect that we'll have bids for natural gas resources, and those natural gas bids will be evaluated in the resource acquisition process, but other bids potentially could come in. Whether those bids would be cost-effective, or whether they will be able to meet the type of Xcel's need, is for that bid to show."

Staff agrees with the Department's comment that setting the type means setting what is needed for Xcel to meet its customers' needs, not determining or limiting what will be bid into the resource acquisition process. The resource plan outlines whether Xcel needs baseload, intermediate, or peaking load, and the resource acquisition process identifies the proposals to meet that need.

As discussed in further detail in the *Party Positions* section above, the Department filed comments recommending the Commission require Xcel "to pursue up to 500 MW of natural gas fired (peaking and intermediate) capacity for implementation in the 2017 to 2019 time frame. " Xcel recommended the

[25] Docket No. E-002/CN-12-1240, Order Approving Notice Plan, January 30, 2013.

Commission "not specify the resource type," but "set the need at 154 MW in 2017, 319 MW in 2018, and 443 MW in 2019."

Both recommendations are included in the Decision Options, but Staff proposes a third "generic option" which includes the size and timing in line with both DOC and Xcel, but eliminates the fuel source (natural gas). Instead, the generic option identifies type consistent with the Department's comments during Deliberation on November 1, 2012, and with the characteristics (baseload, intermediate, or peaking) of Xcel's resource need identified in the modeling filed December 18, 2012.

The "Generic Option"

The Department's modeling commonly finds that 378-492 MW are added in the 2017-2019 timeframe. According to the Department, "the top ten plans contain a mixture of variations on the 'CT plus wind' plan and the 'CT plus CC' plan."

Since the Department defines "intermediate" facilities as "gas-fired CC facilities or gas-fired CT facilities with wind or other energy sources," and since it is the Department's position that "type" does not determine a fuel source, Staff presents a generic option as an alternative to DOC's recommendation that does not identify a fuel preference:

- *Decision Option #2*: Based on the modeling in the record to date, Xcel will likely need to add up to 500 MW of capacity prior to 2020, and a combination of peaking and intermediate capacity should be considered to meet that need.

This option would allow Xcel to set more flexible parameters of the resource acquisition process, and allow bidders to see a range of need. This option would also provide flexibility to Xcel in acquiring its energy need from different sources, such as wind additions. In addition, identifying a type of need generically would allow Xcel to bid in its own peaking facilities, but also evaluate other resources serving a similar need, such as a wholesale market PPA.[26]

DOC's Recommendation

The Department recommends the Commission:

- order Xcel to pursue up to 500 MW of natural gas fired (peaking and intermediate) capacity for implementation in the 2017 to 2019 timeframe. The specific type of capacity should be determined based upon actual bids submitted in the competitive resource acquisition proceeding.

According to the Department's analysis, "it appears at this time that if CT units are eventually selected, wind additions would also be necessary." The Department may wish to weigh in on whether their recommendation to add natural gas capacity captures this modeling result to add wind as well.

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[26] A Department recommendation in their initial June 12, 2012 comments was for Xcel to "use short term purchases to fill any capacity needs in 2015-2016." This recommendation, however, was made assuming the Prairie Island EPU would continue.

The Department's modeling suggests that Xcel's needs reflect the characteristics of an intermediate resource. Page 11 of DOC's comments discusses the "CT plus wind" and "CT plus CC" plans:

> "[A]ll versions of the Department's modeling show that there are two plans for providing an intermediate resource that are close in total cost terms. The Department concludes that the modeling results indicate that the two plans are so close that it would be helpful for the determination regarding the best plan regarding specific type of natural gas capacity to be made with actual data rather than with generic expansion units."

What is not necessarily clear is the extent to which parties agree that Xcel needs to acquire an intermediate resource *through the competitive resource acquisition process*. Xcel's modeling shows an intermediate plant is cost-effective, but its need is deferred when Strategist adds wind or purchases energy from the wholesale market. It is also not overtly clear from the December 12, 2012 comments what impact incremental increases in the production capability at High Bridge and Riverside have on the Company's energy requirements.

The Environmental Intervenors disagree altogether that Xcel even has an energy deficit, and instead conclude the Company's need is for capacity only.

Overall, Xcel recommends the Commission make no finding on type. The Department has been consistent throughout this docket that Xcel's needs extend beyond peaking facilities. (DOC opposed Xcel's withdrawal of the Black Dog Repowering Project and recommended Xcel pursue the Prairie Island EPU.) The EIs disagree with the Department's recommendation for the Commission to find that natural gas should be implemented for the 2017-2019 timeframe. Calpine supports the Department's approach of establishing a need of approximately 500 MW of natural gas capacity in the 2017 to 2019 timeframe and agrees that the resource acquisition process should solicit proposals for both peaking and intermediate resources.

Ultimately, it may be of little consequence whether a generic option or the Department's recommendation is adopted. However, both options are available in case the Commission decides to keep "type" restricted to baseload, intermediate, or peaking, or if the Commission decides that the record is sufficiently developed such that a particular fuel source stands out as clearly beneficial to Xcel's customers.

As discussed on page 6 of this document, the Department's recommendation to include natural gas may be, in part, to acknowledge the significant work that has been done in this record. DOC's explicit fuel source recommendation may be unique in this circumstance (i.e. relative to other resource plans) because the modeling has either come too far for the "type" question to be re-opened entirely, or has clearly shown natural gas to be least-cost relative to other resource options.

<u>Xcel's Recommendation</u>

Xcel recommends the Commission specify the estimated generation deficits by year –154 MW in 2017, 319 MW in 2018, and 443 MW in 2019 – to provide project developers with specific guidance regarding the size and timing of the Company's resource needs.

Staff agrees with Calpine's analysis of Xcel's recommendation on page 2 of Calpine's comments. Calpine opposes Xcel's recommendation for the Commission to identify specific capacity deficits in exact years for the following reasons:

1. "Xcel's recommendation fails to account for the imprecise nature of resource planning. Actual demand growth does not always follow a smooth curve and the most cost-effective resource additions are often 'lumpy' – *i.e.*, they have economies of scale or other attributes that provide superior long-term value even though they might result in a modest short-term over-build.

2. Xcel's recommendation would unnecessarily restrict the range of proposals by favoring roughly equal annual capacity additions over other potential solutions. Indeed, nothing in the Department's modeling appears to suggest that three equal capacity additions represent the least cost approach under any of its modeling scenarios.

3. Xcel's recommendation represents a limitation that would bias the process towards combustion turbines, which can more easily be developed in 150 MW increments than other types of resources, such as combined-cycle. Indeed, adopting Xcel's recommendation to provide such 'specific guidance' would effectively bias the process toward Xcel's own proposed project.

4. Xcel's recommendation is inconsistent with the concept that the Commission should not be overly specific with respect to the type of project(s), but should let the competitive process itself determine the outcome."

Calpine rejects Xcel's argument that specifying the estimated generation deficits by year provides "specific guidance." In Calpine's view, this guidance "is not necessary and would be counterproductive."

The Department addresses this issue further on page 3 of its reply comments:

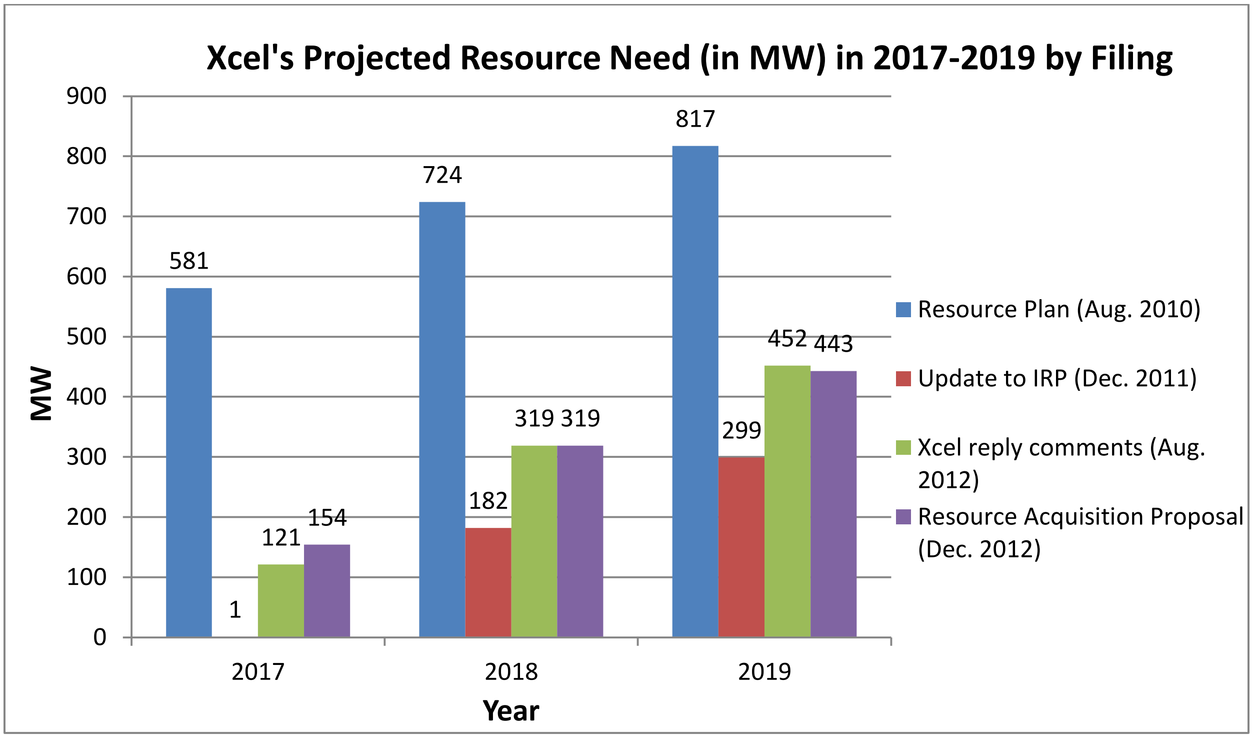
> "The figures provide general, not precise, guidelines, which bidders, including Xcel, can use in designing their bids. However, moving to the analysis of more specific proposals, the actual amounts of different types of capacity (e.g. peaking, etc.) that Strategist selected as being least-cost appears to be highly sensitive to the specifics of the proposed capacity, and how the capacity additions interact overall with Xcel's system.
>
> Because the results of modeling Xcel's system produced wider variations than is typically seen in the type of capacity that is least-cost, the Department recommended that Xcel pursue up to 500 MW of natural gas fired facilities in the 2017 to 2019 time frame without identifying the amounts of intermediate or peaking capacity."

If Xcel and DOC are in agreement that the appropriate mix of intermediate and peaking capacity should be determined by the competitive resource acquisition process, and if the total amount of capacity added, according to the Department, is "highly sensitive" to whether it is peaking or intermediate (because of its interaction with Xcel's overall system), it makes sense for the Commission to avoid determining an exact size at this time.

<u>Xcel's Projected Resource Need</u>

In addition to the comments from the parties as to whether the Commission should specify capacity deficits by year, Staff notes that Xcel's projected resource need has changed with each subsequent filing.

The table below shows Xcel's projected resource need (in MW) in each year of the 2017-2019 timeframe indicated in the following filings: the initial resource plan filing, the December 2011 Update, Xcel's resource plan reply comments, and the proposed need for resource acquisition process.



This is not to say Xcel is forecasting its need incorrectly. Instead, this range simply points out the fact that, within 28 months of record development, Xcel's forecasted need has been subject to changes in the economy, changes in MISO, and other factors which have resulted in very different results of need.

The Environmental Intervenors argue that "to the extent the forecast demand data are reliable, Strategist shows Xcel will have a capacity deficit rather than an energy deficit. As a result, and assuming that the deficit is real, other resources such as demand response and solar photovoltaics could reasonably fill this deficit."

While the EIs contend Xcel's baseline forecast overestimates the projected need, the Department, on the other hand, has argued throughout this record that the Company's assumed needs are too low for the 15-year planning period. DOC concludes Xcel's forecast[27] (upon which the resource need is based) is appropriate for planning purposes, but the Department's June 12, 2012 "preferred plan" strongly considered the contingency in which load growth was higher than in the base case:

[27] In Xcel's December 2011 Update, Xcel adjusted its demand and energy forecasts downward, revising them to 0.7% annual demand growth and 0.5% annual energy growth over the planning period.

> "[I]n resource planning, the important factor to keep in mind is that forecasts of energy and demand requirements are expected to change substantially over the next 15 years as the economy continues to recover and use of energy by industry and residential consumers increases. It would not be appropriate to assume that the lower demand due to the economic downturn will continue in the long term, nor to plan for an electrical system that is based on energy forecasts occurring during economic downturns since reliability of the electric system as a whole is critical to the health of the economy."[28]
>
> "Despite this concern about Xcel's forecasts, in the context of resource planning these issues can be addressed by using the usual ranges of forecasting in capacity expansion models. Therefore, the Department recommends approval of Xcel's energy forecast and the Department's peak demand forecast for planning purposes only."[29]
>
> "The Department typically uses two forecast bands as contingencies in each Strategist scenario; in this case a 'Mid-high,' or 75th percentile, forecast and a 'High,' or 95th percentile, forecast were used. In this case, due to the significance of the Department's concerns with Xcel's forecasting, including concerns that Xcel was under-forecasting its demand, and to gain better insight into forecast risk, the Department took the unusual step of running two entire scenarios focused on the forecast bands. The Department considered the forecast range, especially the 75th percentile results, in determining a preferred plan."[30]

The Department's December 18, 2012 comments used the same model that was used for DOC's June 12, 2012 comments in this docket, which presumably means the issues DOC have with Xcel's baseline forecasts still exist. DOC's Mid-high forecast contingency in their December 18, 2012 modeling adds an additional 189 MW peaking unit, which means, in this contingency, Xcel's need would be higher than DOC's "up to 500 MW" recommendation. Why this is important is because DOC's resource acquisition recommendation may *not* ultimately preclude Xcel from maximizing its demand response resources in 2017-2019, especially if retiring Sherco 1 and 2 during the planning period is still an open question.[31]

Conversely, subtracting 300 MW of DSM from the "up to 500 MW" of need recommended by the Department, or delaying the competitive resource acquisition study until a demand response study can be developed, may preclude Xcel from cost-effectively procure a combined cycle facility, which DOC's analysis suggests might be needed. The EIs argue that Xcel's capacity deficit "does not warrant the rush to acquire capacity in March 2013." However, based on comments already made in the record by several parties, it seems likely that delaying the competitive resource acquisition process another nine months would effectively eliminate Calpine's ability to construct their proposal to meet a 2017 deadline.

Nevertheless, Staff believes that, at this time, Commission Order Point #5a in this resource plan sufficiently addresses Xcel's ongoing consideration of efforts to increase demand response:

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[28] DOC Aug 13, 2012 reply comments, p. 4.
[29] DOC June 12, 2012 initial comments, p. 6
[30] DOC Aug 13, 2012 reply comments, p. 7.
[31] According to the EIs June 12, 2012 comments: "[T]he runs we requested the Company perform on our behalf show that across many of Xcel's sensitivities, the decision to retire Sherco 1 and 2 in 2017 rather than retrofit it is nearly equal on a [Present Value Revenue Requirement] basis."

5. "By February 1, 2014, Xcel shall file its next resource plan.

    a. In preparing this plan, Xcel shall do the following:

        - Consider the goal of achieving participation rates for demand response programs in the top 25 percent of such programs nationwide, as addressed in Xcel's 2012 Demand-Side Management Market Potential Assessment, to help meet projected demand in the 2017-2019 timeframe."

Staff believes that it is not necessary to delay, or subtract need from, the resource acquisition parameters, and require Xcel to procure 300 MW of demand response in 2017-2019 instead. The Commission Order already requires Xcel to consider achieving higher levels of demand response in its next resource plan. Moreover, the Department and Xcel agree that the DSM potential study cited by the EIs "was not specific enough to Xcel's system such that it could be used to reduce the specified demand forecast."[32]

[32] DOC's January 18, 2013 reply comments, p. 3.

Decision Options

1. Approve Xcel Energy's 2011-2025 resource plan for planning purposes only. This finding of approval does not extend to particular generation projects that will be subject to review under future proceedings, but is a general finding that the plans filed by Xcel appear to be sufficient for planning purposes.

2. Based on the modeling in the record to date, Xcel will likely need to add up to 500 MW of capacity prior to 2020, and a combination of peaking and intermediate resources should be considered to meet that need.

Department of Commerce recommendation

3. Require Xcel to pursue up to 500 MW of natural gas fired (peaking and intermediate) capacity for implementation in the 2017 to 2019 timeframe. The specific type of capacity should be determined based upon actual bids submitted in the competitive resource acquisition proceeding.

Xcel Energy recommendations

4. Set Xcel Energy's resource need at 154 MW in 2017, 319 MW in 2018, and 443 MW in 2019.

5. Make no finding on the specification of the resource type. Instead, the competitive resource acquisition process should identify the most cost-effective proposals.

6. Provide participants in the competitive resource acquisition process the flexibility to offer peaking or intermediate resources or a combination of the two, as well as the flexibility to address all or a portion of the identified need.

7. Allow proposals in the competitive resource acquisition process from existing generators.

8. Take no action at this time to reduce the estimated resource need based on potential demand response benchmarking.

Environmental Intervenors recommendations

9. Find that it is premature to initiate a competitive resource acquisition proceeding at this time. Instead, the following actions should be taken:

    a. Require Xcel to begin immediately and complete within 9 months a thorough demand response potential evaluation that can be relied on in forecasting future need.

    b. Incorporate the evaluation of Xcel's capacity needs over the 2017 to 2019 timeframe into the existing Sherco study.

    c. Require Xcel and the Department to use the most recent forecast data available in their analyses of Xcel's capacity needs.

    d. Direct Xcel and the Department to make available to the Strategist model other resources, including market purchases, distributed generation resources, and additional DSM.

10. If the Commission determines to move forward with the competitive resource acquisition proceeding:

    a. Xcel has the burden to demonstrate in the contested case proceeding that it has the stated capacity need, and that the need cannot be met more cost-effectively through DSM or renewable resources.

    b. Flexibility for participants to offer all types of resources, including supply-side and distributed generation resources, as well as flexibility to address all or a portion of the identified need.

Staff recommends: 1 and 2.

(Since Docket No. CN-12-1240 established a schedule for the competitive bidding process and approved Xcel's notice plan announcing it, Staff believes Decisions Options 6, 7, 8, and 10a. are consistent with adopting options 1 and 2. However, Staff does not object to Decision Options 6-8 or 10a., should the Commission, or the parties, believe making these specific findings is a necessary step.)

Attachment A: Commission's November 30, 2012 Order in Xcel's Resource Plan

ORDER

1. With respect to the current docket, the Commission establishes the following procedural schedule:

    - December 18, 2012: Deadline to file comments. The Department and Xcel shall file any final revisions to their models and analysis.

    - January 16, 2013: Deadline to file reply comments.

    - February 2013: Commission action and docket closure.

2. By January 16, 2013, Xcel shall file a notice plan for soliciting bids as part of Xcel's competitive resource acquisition process, as provided in In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process, Docket No. E 002/CN-12-1240, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

3. By July 1, 2013, Xcel shall file a fuel acquisition and risk management plan.

4. By July 1, 2013, Xcel shall submit a Sherco Life Cycle Management Study that examines the feasibility and cost-effectiveness of continuing to operate, retrofitting, or retiring Sherburne County (Sherco) Generating Station Units 1 and 2. Procedurally, interested parties shall have the opportunity to intervene, conduct discovery, and comment. Substantively, the study shall include –

    A. Specific cost estimates of controls and other required investments.

    B. An analysis of how a temporary or permanent outage at either Sherco Units 1 or 2 would affect system reliability.

    C. A base case that includes Commission-adopted carbon dioxide (CO2) costs and externality values.

    D. A base case that accounts for all likely federal Environmental Protection Agency (EPA) regulations.

    E. Analysis of scenarios that include the following:

        - A range of updated externality values based on those used by this Commission and the federal government for regulatory impact analyses.

        - A wide range of fuel prices.

        - Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050.

- A least-cost plan for replacing 50 percent of the capacity of Sherco Units 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy

- A least-cost plan for replacing 75 percent of the capacity of Sherco Units 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy.

5. By February 1, 2014, Xcel shall file its next resource plan.

   A. In preparing this plan, Xcel shall do the following:

   - Consider the goal of achieving participation rates for demand response programs in the top 25 percent of such programs nationwide, as addressed in Xcel's 2012 Demand-Side Management Market Potential Assessment, to help meet projected demand in the 2017-2019 timeframe.

   - Reassess acquiring new wind generation for the 2015-2016 timeframe.

   - Evaluate the costs, benefits, and effects of including higher levels of distributed generation, including industrial-sized distributed generation, utility-scale solar, and combined heat and power.

   - Work with interested parties to identify useful ways to estimate how implementing Xcel's preferred resource plan would affect customer rates and bills, and incorporate those estimates into the resource plan filing.

   B. In the plan, Xcel shall include the following:

   - Scenarios that evaluate higher levels of cost-effective and feasible demand response capability.

   - A base case with CO2 values consistent with the Commission-approved range of $9 to $34 per ton beginning in 2017.

   - Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050.

   - An assessment of Xcel's prospects for acquiring more electricity generated by wind power.

   - A least-cost scenario for meeting 50 percent of the need for any new or refurbished capacity through a combination of conservation and capacity powered by renewable energy, and a least-cost scenario for meeting 75 percent of this need through conservation and renewable sources, consistent with Minn. Stat. § 216B.2422.

- A comprehensive section on all EPA rules which may affect Xcel's operations.

6. This Order shall become effective immediately.

Attachment B: Minnesota Rules and Statutes, Commission Review of Resource Plans

Commission Review

Chapter 7843.0500 COMMISSION REVIEW OF RESOURCE PLANS.

Subpart 1.

Decision.

Based upon the record, which is the information filed with the commission in the resource plan proceeding of a utility, including responses to information requests, the commission shall issue a decision consisting of findings of fact and conclusions on the utility's proposed resource plan and the alternative resource plans. If the commission determines there is insufficient information upon which to issue findings and conclusions, it may delay issuing its decision to permit production of the desired type and level of information.

Subp. 2.

Resource plan.

A utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. The utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing.

Subp. 3.

Factors to consider.
In issuing its findings of fact and conclusions, the commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;

B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

C. minimize adverse socioeconomic effects and adverse effects upon the environment;

D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Subp. 4.

Issues requiring further consideration.
In its decision, the commission may direct the utility to provide in its next resource plan filing a discussion of specified issues. The issues may include those not totally resolved in the current proceeding and those for which the state of knowledge is changing substantially between resource plan filings.

Subp. 5.

Changed circumstances affecting resource plans.

The utility shall inform the commission and other parties to the last resource plan proceeding of changed circumstances that may significantly influence the selection of resource plans. Upon receiving notice of changed circumstances, the commission shall consider whether additional administrative proceedings are necessary before the utility's next regularly scheduled resource plan proceeding.

Subp. 6.

Authority of other agencies.

Issuance of a resource plan decision by the commission does not limit the statutory authority of other agencies in their regulatory responsibilities.

Statutory Authority:

MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05

Minn. Stat § 216B.2422, Subd. 2. (Resource Planning)

Subd. 2. **Resource plan filing and approval**.

A utility shall file a resource plan with the commission periodically in accordance with rules adopted by the commission. The commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest. In the resource plan proceedings of all other utilities, the commission's order shall be advisory and the order's findings and conclusions shall constitute *prima facie* evidence which may be rebutted by substantial evidence in all other proceedings. With respect to utilities other than those defined in section 216B.02, subdivision 4, the commission shall consider the filing requirements and decisions in any comparable proceedings in another jurisdiction. As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.

Content of Resource Plans

Chapter 7843.0500, CONTENTS OF RESOURCE PLAN FILINGS

According to Minn. Rule 7843.0100, Subp. 9.:

> "'Resource plan' means a set of resource options that a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs."

Minn. Rules part 7843.0500, subp. 3B states that:

> "In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:
>
> A. maintain or improve the adequacy and reliability of utility service;
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

Furthermore, a utility is "only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements."

The purpose of a resource plan is to strengthen a utility's long term planning processes by providing input from the public, regulatory agencies, and the Commission. Integrated resource planning (IRP) was developed to ensure that utilities evaluate supply- and demand-side resources such that a "least cost" resource plan is selected. By its nature, a resource plan is a "big picture" evaluation of the future, not a study of customer class rate impacts. If the IRP process is performed correctly, the result will be the least cost plan, which in turn implies reasonable rates for all customers.

Other Commission dockets such as certificate of need provide information on individual projects but do not necessarily help the Commission and stakeholders understand how and why a particular project was selected. By contrast, a resource plan can provide that planning information but not specific project approvals.[33] Furthermore, Commission approval or rejection of a resource plan does not extend to particular generation projects that are currently under review in other proceedings or will be subject to review under future proceedings. Instead, it is a general finding that the plan filed by a utility appears to be reasonable, or not.

The Commission's decision in a resource plan may be "officially noticed or introduced into evidence in related Commission proceedings;" however, according to Minn. Rules 7843.0600, Subp. 2., a finding or

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[33] In specific circumstances in which a large energy facility is proposed in the resource plan and likely to begin construction prior to filing of the utility's next resource plan, the Commission is to conduct the resource plan proceeding consistent with 216B.243. In this particular instance, approval of the facility within the resource plan would negate the need for a separate certificate of need process (see Minn. Stat. 216B.2422, subd. 6).

decision in a resource plan would constitute "*prima facie* evidence" in the related proceeding. Therefore, conclusions and findings of fact in a resource plan can still be rebutted, and such *prima facie* evidence is not conclusive, nor irrefutable.

Attachment C: Relevant Statutes to the Resource Planning Process

Statutes such as the following would be part of a utility's analysis in resource plan proceedings:

Environmental externalities. Originally passed by the legislature in 1993 and codified in Minn. Stat. §216B.2422, subd. 3, the statute requires the Commission "to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation." The law requires each utility to use the values in conjunction with other external factors when evaluating resource options in all proceedings before the Commission.

Carbon values. Passed by the legislature in 2007, Minn. Stat. §216H.06 requires the Commission to establish, by January 1, 2008 and updated annually thereafter, an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation to be used in all electric generation resource acquisition proceedings.

Minnesota CO_2 Goal. Minn. Stat. §216H.02 established goals of achieving a 15 percent reduction in CO_2 emissions from 2005 levels by 2015, a 30 percent reduction by 2025, and an 80 percent reduction by 2050.

Conservation. Minn. Stat. §216B.2421, subd. 1c(d), amended in 2007, requires that the Commissioner of the Department of Commerce may not approve a CIP (Conservation Improvement Program) plan that provides for an annual savings goal of less than one percent of gross annual retail energy sales. Minn. Stat. 216B.2401 states that it is the energy policy of the state to achieve annual energy savings of 1.5 percent.

Renewable energy. Minn. Stat. §216B.1691, amended in 2007, establishes renewable energy obligations and standards. Minn Stat. §216B.2422 requires a resource plan to include low and high load growth scenarios and scenarios that evaluate meeting 50 percent and 75 percent of future resource needs using demand-side management and renewable resources. Minn. Stat. §216B.2422, Subd. 4, prohibits the Commission from approving a nonrenewable energy facility in a resource plan unless the utility has demonstrated that a renewable energy facility is not in the public interest.

Greenhouse Gas Control Plan. Passed in 2007, Minn. Stat. §216H.03 states that, in the absence of federal or state laws requiring enforceable limits on CO_2 emissions, no new large energy facility can be constructed within the state, commit to import from outside the state, or enter into a long-term PPA, power that would contribute to statewide power sector carbon dioxide emissions (with a number of exemptions and exceptions).

C-BED Goal. Under Minn. Stat. §216B.1612 subd. 5(b), a resource plan must include a description of efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.

Attachment E

Xcel Energy – Wind RFP Update
February 4, 2013

414 Nicollet Mall
Minneapolis, MN 55401

February 4, 2013

—Via Electronic Filing—

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

RE: WIND RFP UPDATE
2011-2025 RESOURCE PLAN
DOCKET NO. E002/RP-10-825

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits this letter to the Minnesota Public Utilities Commission to inform the Commission and interested stakeholders of our intent to issue a Request for Proposals (RFP) for up to 200 MW of wind generation resources. With the extension of the federal renewable electricity production tax credit (PTC) effective January 2, 2013, we believe it is prudent to assess opportunities for additional wind resources on our system at this time to determine if there are cost-effective wind projects that could provide long-term value to our customers.

The January 2013 federal legislation replaced the PTC requirement that a wind project be placed in service by the end of 2012 with a requirement that a wind project begin construction activities by the end of 2013. With this extension in place, it is our intent to issue the wind RFP as soon as February 15, 2013 to ensure there is time for any new project that may be selected to begin construction in 2013.

Consistent with the process used for our last wind RFP issued on September 15, 2010, we are informing the Commission of our intent to issue the RFP. If we receive proposals that warrant proceeding with a project, we will bring these selections forward for Commission approval once the process has been completed. We discuss further below the expected timeline for completion of this process.

During our current Resource Plan proceeding, we indicated that because we currently have enough renewable energy credits to meet RES compliance requirements through 2020, there was sufficient time to revisit adding wind to our system once the PTC issue was settled. The PTC has now been extended, but only for a short time. Requesting proposals for additional wind generation now will allow us the opportunity to consider cost-effective wind projects; at the same time, we continue to have the option to defer acquisition of wind and remain on track with renewable energy compliance. Thus, by issuing the RFP, we are not committing to add wind generation if our analysis shows no projects would provide reasonable benefits for our customers over the long term.

We note that this wind RFP will not impact the resource need or timing of the competitive acquisition process currently pending before the Commission in Docket No. E002/CN-12-1240. The resource need under consideration for that competitive acquisition process is in the range of up to 500 MW. With a wind accreditation factor of 13 percent, any capacity addition related to the 200 MW of wind resources we are seeking would not be significant enough to affect the identified need on our system. As such, the competitive capacity resource acquisition process will continue once the Commission makes its determination in February on the size, type, and timing of the resource addition, and we will begin that resource acquisition process in March 2013 as designed.

Assessing opportunities to add wind resources on our system now is consistent with the approach we have taken in the past, where we have added cost-effective wind where appropriate in advance of renewable energy compliance milestones. This strategy has served our customers well over time, allowing us to add cost-effective wind to our system when there is an opportunity to do so, avoiding the need to add significant renewable resources just in advance of when they would be required, which could conceivably be less advantageous for our customers.

The desired outcome of the wind RFP process is to add wind resources if they are shown to provide benefits to our customers over the long term. Our RFP will seek up to 200 MW of wind resources from existing or new projects. While the Company is interested in ownership opportunities to balance our portfolio, we will accept proposals for all types of structures, including utility ownership arrangements and power purchase agreements of all types, including C-BED structured proposals. Further, we will accept proposals of differing sizes at various locations, which will allow us the flexibility to add up to 200 MW through any combination of a long-term PPA and/or Company ownership.

We believe the following timeline provides the opportunity for potential project developers to meet the PTC deadline to begin construction by December 31, 2013:

Issue Wind RFP	February 15, 2013
Proposals Due	April 1, 2013
Evaluations Conducted	April-May 2013
Contract Negotiations	June 2013
Decision Report/Selections filed with Commission	July 2013

Consistent with the regulatory process in Minnesota and North Dakota, we will make the appropriate filings with both the Minnesota Commission and the North Dakota Public Service Commission seeking the necessary regulatory approvals for any projects selected.

We look forward to working with project developers through the wind RFP process in 2013. We are available to answer any questions the Commission or stakeholders may have at this time.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists. Please contact me at james.r.alders@xcelenergy.com or (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

c: Service Lists

Attachment F

Minnesota Public Utilities Commission
Xcel Energy IRP Order
MPUC Docket E-002/RP-10-825

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan

ISSUE DATE: March 5, 2013

DOCKET NO. E-002/RP-10-825

ORDER APPROVING PLAN, FINDING NEED, ESTABLISHING FILING REQUIREMENTS, AND CLOSING DOCKET

PROCEDURAL HISTORY

On August 2, 2010, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a resource plan under Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, covering the period 2011-2025. Since that time Xcel has occasionally revised the data upon which its plan was based, and also revised its plans.

On November 30, 2012, the Commission issued its Order Establishing Procedural Schedules and Filing Requirements which, among other things, did the following:

- Established a schedule for filing forecasts of the amount of additional resources Xcel would need to meet customer demand, and for filing comments on the forecasts.

- Directed Xcel to file a notice plan for soliciting bids in Docket No. E-002/CN-12-1240, *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process.*

- Directed Xcel to develop a plan to either update or replace the Sherburne County (Sherco) Generating Station Units 1 and 2, the two oldest coal-powered generators at Xcel's largest plant.

- Identified topics for Xcel to address in its next resource plan.

Since November 30, 2012, the Commission has received comments from the following:

- Minnesota Department of Commerce (the Department)
- Calpine Corporation, a developer of electric generators

- Flint Hills Resources, LP, Gerdau Ameristeel Corporation, and USG Corporation, filing jointly (the Xcel Large Industrials)
- Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and the Minnesota Center for Environmental Advocacy, filing jointly (the Environmental Intervenors)
- Xcel

On February 20, 2013, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Summary

In the order the Commission does the following:

- Approves Xcel's resource plan for planning purposes and closes the current docket.

- Finds that the record demonstrates a need for an additional 150 MW by 2017, increasing up to 500 MW by 2019.

- Authorizes entities to propose to provide the resources for meeting some or all of Xcel's needs.

- Provides direction for Xcel's next resource plan.

II. Legal Background

A. Resource Planning

To reliably provide the electricity demanded by its customers, an electric utility considers both supply and demand. The utility can supply electricity through a combination of generation and power purchases, and by reducing the amount of electricity lost through transmission and distribution. The utility can manage its customers' demand by encouraging customers to conserve electricity or to shift activities requiring electricity to periods when there is less demand on the electric system. A resource plan contains a set of demand- and supply-side resource options that the utility could use to meet the forecasted needs of retail customers.[1]

A public utility providing electricity to at least 10,000 customers and capable of generating 100 megawatts (MW) of electricity must file a resource plan or report for the Commission's approval, rejection, or modification.[2] Generally, the resource planning statute and rules direct a utility to file biennial reports on the projected need for electricity in its service territory, and the utility's plans for meeting projected need, including the actions it will take in the next five years.[3] By integrating the evaluation of supply- and demand-side resource options – treating

[1] Minn. Stat. § 216B.2422, subd. 1(d).

[2] Minn. Stat. § 216B.2422, subds. 1 and 4. The statute exempts federal power agencies, and the Commission's findings regarding service providers that are not statutory "public utilities" are merely advisory.

[3] Minn. Stat. § 216B.2422; Minn. R. Chap. 7843.

each resource as a potential substitute for the others – a utility can find the least-cost plan that is consistent with the other legal requirements and policies.

B. Xcel's Competitive Bidding Process

The Commission authorizes Xcel to secure new resources through a competitive bidding process, as permitted under Minn. Stat. § 216B.2422. subd. 5.[4] Xcel has initiated the process for soliciting proposals for meeting the needs to be identified in this docket.[5]

III. Positions of the Parties

A. Xcel

Based on its analysis, Xcel's revised five-year action plan includes the following elements:

- Retiring Black Dog Units 1 and 2, but canceling plans to acquire replacement power.
- Canceling the further expansion of the generating capacity of the Prairie Island Nuclear Power Plant.
- Continuing the operation of the Key City generator in Mankato (43 MW) and Granite City generator near St. Cloud (54 MW) until 2016, and bringing the French Island Unit 3 generator (57 MW) back into service.
- Continuing to analyze whether to update or replace Sherco Units 1 and 2.
- Soliciting proposals for an additional 200 MW of wind-powered electricity.
- Continuing to use demand-side management programs such as offering discounts to customers that permit Xcel to interrupt electric service during time of peak demand, estimated to reduce the demand on Xcel's system during periods of peak demand by approximately 1000 MW.
- Continuing to use demand-side management to reduce energy sales by 1.3 percent, and working with stakeholders to achieve even greater savings.
- Continuing programs involving solar energy, including Solar*Rewards – a program subsidizing customer purchases and installation of photovoltaic solar cells[6] -- albeit with lower subsidies for enrollees.

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[4] See *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2005 - 2019 Resource Plan*, Docket No. E-002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, and Requiring Compliance Filing (May 31, 2006).

[5] See *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, Docket No. E-002/CN-12-1240, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

[6] See Docket No. E,G-002/CIP-12-447, *In the Matter of the Implementation of Northern States Power Company, a Minnesota Corporation's 2013/2014/2015 Triennial Natural Gas and Electric Conservation Improvement Program*.

Based on its forecasts, Xcel argues that it will need an additional 154 MW by 2017, 319 MW by 2018, and 443 MW by 2019 to meet anticipated customer demand. Xcel asks the Commission to affirm this level of need, and this degree of specificity, arguing that the information would be useful to entities that might provide resources as part of Xcel's competitive bidding process.

To attract the broadest range of projects for its consideration, Xcel asks the Commission to grant a wide degree of latitude to potential bidders in Xcel's competitive resource acquisition process. In particular, Xcel proposes soliciting bids that 1) meet all or any portion of the need, 2) rely on any fuel type, 3) rely on new or existing generators, and 4) rely on intermediate or peaking generators, or both – that is, any generators other than base-load generators designed to run on a continuous basis.

However, Xcel opposes proposals to reduce the amount of Xcel's forecasted need based on the assumption that Xcel can increase the amount of savings it can achieve through demand-side management. While Xcel's own study concluded that Xcel could save 300 MW through the use of demand-side management, Xcel argues that the study was insufficiently rigorous to provide a basis for altering its demand forecasts.

B. Environmental Intervenors

The Environmental Intervenors argue that it is premature to close the current docket or initiate a competitive resource acquisition proceeding. Instead, the Environmental Intervenors recommend that the Commission do the following:

- Direct Xcel and the Department to re-analyze Xcel's resource plan based on the latest forecast data.

- Direct Xcel to evaluate the potential savings Xcel could achieve through implementing demand-side management programs, and to quantify these savings with sufficient rigor to enable Xcel to rely on the estimate when forecasting future resource needs.

- Direct Xcel to look for opportunities to integrate solar power into its resource mix.

If and when the Commission initiates the competitive resource acquisition process, the Environmental Intervenors support Xcel's proposal to solicit the broadest range of resources for consideration.

Finally, before the Commission approves any new supply-side resource, the Environmental Intervenors argue that the Commission should require Xcel to demonstrate in a contested case proceeding that Xcel has sufficient need to justifying the new resource, and that the need could not be met more cost-effectively through demand-side management or renewably sources of energy.

C. Large Power Intervenors

Echoing some of the Environmental Intervenors' concerns, the Large Power Intervenors caution the Commission against overestimating Xcel's needs. They argue that Xcel developed its forecast of customer demand based on data that is now out of date. Moreover, the Large Power Intervenors note that Xcel recently solicited bids for 200 MW of wind power; these new generators may offset Xcel's alleged resource deficits, they argue.

D. The Department

Using assumptions and analysis that differed somewhat from Xcel's assumptions and analysis, the Department reaches recommendations that are generally similar to Xcel's. In particular, whereas Xcel argues that it will need an addition 443 MW by 2019, the Department predicts that Xcel will need 500 MW within the 2017-2019 timeframe.

The Department also supports Xcel's proposal to grant broad discretion to bidders in Xcel's competitive bidding process. The Department shares Xcel's view that computer models indicate that a variety of alternatives might prove to be the least-cost alternative, and the final choice should be referred to Xcel's resource acquisition docket.

Unlike Xcel, however, the Department asks the Commission to specify that Xcel must pursue new sources of electricity generated from natural gas. According to the Department's analysis, each of ten least-cost scenarios for meeting Xcel's needs involves relying on one or more new gas-fueled generators.

Finally, the Department argues that Xcel should, in its next resource plan, report on the expected amount of solar energy on Xcel's system, barriers Xcel sees to further deployment of solar cells, and new programs for promoting solar power that might replace the Solar*Rewards program.

E. Calpine

Calpine supports both Xcel's and the Department's proposals to solicit resource proposals broadly, without restricting the type of generators to be considered.

Calpine favors the Department's recommendation to find that Xcel needs 500 MW within the 2017-2019 timeframe. Calpine argues that Xcel's proposal -- identifying a precise level of need for each year – could discourage rather than encourage potential bidders because it may hint that Xcel may have already identified the projects that it will meet those specific targets.

IV. Commission Analysis and Action

A. Xcel's Resource Plan

Parties from varying perspectives have now had sufficient opportunity to scrutinize and challenge the data and analysis underlying Xcel's resource plan, and have had the opportunity to share their comments with this Commission. Having reviewed these comments along with the rest of the record, the Commission concludes that Xcel's plan is reliable for planning purposes. Consequently, the Commission will approve it, and will close this docket.

The Environmental Intervenors ask the Commission to refrain from approving the plan until Xcel has further refined it by, for example, considering more recent forecast data. And they argue that approval of Xcel's overall resource plan should not relieve Xcel of the duty to justify the acquisition of any specific resource.

The Commission finds that Xcel has fulfilled the requirements of Minn. Stat. § 216B.2422 and Minn. R. Chap. 7843 governing resource planning. Moreover, Xcel filed revised forecasting data less than three months ago. Rather that attempting to address the Environmental Intervenors' concerns by ordering a further revision of forecasting data, the Commission will refer these concerns to Xcel's next resource plan that Xcel is due to file in the next 11 months.

Finally, the Commission notes that it is approving Xcel's plan for planning purposes only. This approval does not relieve Xcel from the need to comply with any regulatory review required for any specific resource it might pursue in implementing this plan.

B. Competitive Resource Acquisition Process

The current resource planning docket will have a direct bearing on Xcel's competitive bidding process. In particular, the current docket supports the finding that Xcel will need an additional 150 MW in 2017, increasing up to 500 MW by 2019. Moreover, a broad range of resources could contribute to meeting this need, justifying solicitation of a broad range of proposals. In particular, Xcel should invite proposals for meeting all of the forecasted need, or any part of it. Xcel should invite proposals for adding peaking resource, intermediate resources, or a combination of the two. Xcel should invite proposals that rely on building new generators, as well as proposals that rely on existing generators.

Commentors largely agree about the advantages of considering a broad range of potential resources. While the Department recommends that the Commission direct Xcel to seek gas-fueled sources of generation in particular, the Commission is not persuaded of the need to prohibit consideration of other alternatives. Rather, the Commission is willing to rely on the bid evaluation process to identify the best alternatives, regardless of type.

In contrast, parties disagree about the magnitude of Xcel's needs. For example, the Environmental Intervenors and the Large Power Intervenors argue that the 500 MW figure may exceed customer demand. In contrast, Calpine and the Department argue that the 500 MW figure is justified, and may even be too low.

The idea that Xcel will need an additional 500 MW by 2019 is well-supported in the record. Indeed, Xcel had previously argued that it would need up to 600 MW of additional capacity – and Xcel generated this estimate before it cancelled plans to add 118 MW of new capacity to its Prairie Island plant.

For purposes of Xcel's competitive bidding docket, the Commission finds it appropriate to solicit proposals for *an additional* 150 MW in 2017, increasing *up to* 500 MW by 2019. This statement does not preclude Xcel from acquiring more than 150 MW of new resources by 2017. Those choices will be made in the context of the resource acquisition docket, based on the proposals and the evidence adduced in that docket.

Finally, Xcel asks the Commission to identify the magnitude of Xcel's forecasted need in each of the years 2017, 2018, and 2019, on the theory that this information would be useful to potential bidders. In contrast, Calpine and the Department argue that Xcel's figures suggest an unwarranted degree of precision in the forecasting process. Calpine even suggests that the figures could discourage potential bidders by signaling that Xcel has selected need specifications to justify a pre-determined conclusion.

The Commission concludes that the degree of specificity in Xcel's statement of resource need is unnecessary. A statement that Xcel anticipates needing an additional 150 MW by 2017, increasing up to 500 MW in 2019, will suffice to inform potential bidders of the scope of projects that the Commission will be considering.

C. Xcel's Next Resource Plan

The Environmental Intervenors, among others, ask the Commission to direct Xcel to further address issues of demand response and solar energy as part of Xcel's resource plan. Rather than prolong the consideration of Xcel's current resource plan, the Commission will adopt the Department's recommendation to have Xcel address these issues in its next plan.

Xcel commissioned a study that suggests that Xcel could avoid the need for an additional 300 MW if Xcel could harness the full potential for demand response in its service area. Xcel argues, however, that the study is too general to be relied upon. For its next resource plan, therefore, the Commission will direct Xcel to analyze the capacity for demand response in its service area – and to conduct the study with sufficient rigor that the Commission may rely on the results for evaluating how demand response will influence Xcel's forecasted need for additional resources.

Similarly, the Commission will direct Xcel to include a report on solar power as part of its next resource plan. This report should note the expected amount of solar energy on Xcel's system, barriers it sees to further solar deployment, and how solar development could contribute to peak demand management, economic development in Minnesota, and meeting Minnesota's renewable energy and environmental mandates and goals.[7]

These filing requirements supplement the other requirements set forth in the Commission's November 30, 2012 order.

<u>ORDER</u>

1. The Commission approves for planning purposes the 2011-2025 Resource Plan of Northern States Power Company d/b/a Xcel Energy, and closes this docket.

2. The Commission finds that the current resource plan demonstrates Xcel's need for an additional 150 MW in 2017, increasing up to 500 MW in 2019.

3. Participants in Xcel's competitive resource acquisition process, Docket No. E-002/CN-12-1240, *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, may propose a variety of resources to meet Xcel's need, including --

    a. Resources to address all or a portion of the identified need;

    b. Peaking resources, intermediate resources, or a combination of the two; and

    c. Resources that rely on new or existing generators.

4. In its next resource plan Xcel shall address, in addition to the issues set forth in the Commission's Order Establishing Procedural Schedules and Filing Requirements (November 30, 2012), the following issues:

[7] See, for example, Minn. Stat. §§ 216B.1691 (renewable energy standards), 216B.2422 (environmental externalities), 216H.02 (carbon dioxide regulations).

a. Solar Energy: Xcel shall report on the expected amount of solar energy on its system, barriers it sees to further solar deployment, and how solar development could contribute to peak demand management, economic development in Minnesota, and meeting Minnesota's renewable energy and environmental mandates and goals.

b. Demand Response: Xcel shall evaluate the potential capacity savings that Xcel could achieve via demand response programs, and the extent to which Xcel may rely on demand response in forecasting future need.

5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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

Attachment G

SEC Form 10-K (selected)

Northern States Power Company

December 31, 2012

Northern+States+Power+Co.+-+MN 10-K 12/31/2012

Section 1: 10-K (NORTHERN STATES POWER COMPANY 10-K 12-31-2012)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 001-31387

NORTHERN STATES POWER COMPANY

(Exact name of registrant as specified in its charter)

Minnesota	**41-1967505**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

414 Nicollet Mall, Minneapolis, Minnesota 55401
(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**

Securities registered pursuant to Section 12(b) of the Act: **None**

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of Feb. 25, 2013, 1,000,000 shares of common stock, par value $0.01 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

Xcel Energy Inc.’s Definitive Proxy Statement for its 2013 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

Northern States Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

INDEX

This Form 10-K is filed by NSP-Minnesota. NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

PART I

Item l — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NMC	Nuclear Management Company, LLC
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The integrated electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries
Federal and State Regulatory Agencies	
ASLB	Atomic Safety and Licensing Board
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPCA	Minnesota Pollution Control Agency
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
PSCW	Public Service Commission of Wisconsin
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
EIR	Environmental improvement rider
EPU	Extended power uprate
FCA	Fuel clause adjustment
GAP	Gas affordability program
PGA	Purchased gas adjustment
RDF	Renewable development fund
RES	Renewable energy standard
SEP	State energy policy
TCR	Transmission cost recovery adjustment
Other Terms and Abbreviations	
AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARC	Aggregator of retail customers
ARO	Asset retirement obligation
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule

CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CO_2	Carbon dioxide
CON	Certificate of need
CPCN	Certificate of public convenience and necessity
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IFRS	International Financial Reporting Standards
JOA	Joint operating agreement
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investor Services
MVP	Multi-value project
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract.
NEI	Nuclear Energy Institute
NOL	Net operating loss
NOx	Nitrogen oxide
O&M	Operating and maintenance
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
PV	Photovoltaic
REC	Renewable energy credit
ROE	Return on equity
RPS	Renewable portfolio standard
RSG	Revenue sufficiency guarantee
RTO	Regional Transmission Organization
SIP	State implementation plan
SO_2	Sulfur dioxide
Standard & Poor's	Standard & Poor's Ratings Services

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

COMPANY OVERVIEW

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is an operating utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately 4 percent of its total KWh sold in 2012. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 89 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2012. Although NSP-Minnesota's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large commercial and industrial electric sales include customers in the following industries: petroleum and coal, as well as food products. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: real estate and educational services. Generally, NSP-Minnesota's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation, which owns NMC, an inactive company.

NSP-Minnesota conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 14 to the consolidated financial statements for further discussion relating to comparative segment revenues, net income and related financial information.

NSP-Minnesota's corporate strategy focuses on three core objectives: obtain stakeholder alignment; invest in our regulated utility businesses; and earn a fair return on our utility investments. NSP-Minnesota files periodic rate cases and establishes formula rates or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations. Environmental leadership is a core priority for NSP-Minnesota and is designed to meet customer and policy maker expectations for clean energy at a competitive price while creating shareholder value.

ELECTRIC UTILITY OPERATIONS

Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction* —** Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC also has regulatory authority over security issuances, property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans for meeting customers' future energy needs. The MPUC also certifies the need for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce. NSP-Minnesota has been granted continued authorization from the FERC to make wholesale electric sales at market-based prices. NSP-Minnesota is a transmission owning member of the MISO RTO.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — NSP-Minnesota has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *CIP* — The CIP recovers the costs of programs that help customers save energy. CIP includes a comprehensive list of programs that benefit all customers including Saver's Switch®, energy efficiency rebates and energy audits.
- *EIR* — The EIR recovers the costs of environmental improvement projects.
- *GAP* — The GAP is a surcharge billed to all non-interruptible customers to recover the costs of offering a low-income customer co-pay program designed to reduce natural gas service disconnections.
- *RDF* — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — The RES recovers the cost of new renewable generation.
- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — The TCR recovers costs associated with new investments in electric transmission.

The MPUC approved NSP-Minnesota's request that the recovery of the costs associated with the EIR and RES be included in base rates in the Minnesota electric rate case as part of the final rates effective Sept. 1, 2012. No costs are being recovered through the EIR at this time. NSP-Minnesota will continue to track PTCs associated with company-owned renewable projects and reflect the difference between the base rate amount and actual costs in the RES adjustment clause.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred cost of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction. The FCA allows NSP-Minnesota to bill customers for the cost of fuel and related costs used to generate electricity at its plants and energy purchased from other suppliers. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or through base rate cases.

Minnesota state law requires electric utilities to invest 1.5 percent of their state revenues in CIP, except NSP-Minnesota, which is required by law to invest 2 percent. NSP-Minnesota was in compliance with this standard in 2012 and expects to be in compliance in 2013. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

CIP Triennial Plan — In October 2012, the Department of Commerce approved NSP-Minnesota's 2013 through 2015 CIP Triennial Plan, which increases the savings goals and budgets over the previous plan. The plan sets an electric goal of annually saving the equivalent of 1.5 percent of sales (calculated on a historical three-year average, excluding opt-out customers) and an annual natural gas goal of saving 1.0 percent of sales. The combined electric and gas budgets average $104 million per year over the 2013 through 2015 period.

Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2013, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2010	**2011**	**2012**	**2013 Forecast**
NSP System	9,131	9,792	9,475	9,215

The peak demand for the NSP System typically occurs in the summer. The 2012 uninterrupted system peak demand for the NSP System occurred on July 2, 2012. The 2011 peak demand occurred on a day with extremely high temperatures and humidity, which resulted in the highest uninterrupted system peak demand since July 31, 2006. The 2012 peak demand occurred uninterrupted on a day with weather much closer to normal peak day conditions. The forecast for 2013 assumes normal peak day weather and includes the impact of the termination of several firm wholesale contracts primarily at NSP-Wisconsin. The 2013 forecast also reflects the impact of two large commercial and industrial customers that have ceased operations. These customers represented 0.05 percent of 2012 sales.

Energy Sources and Related Transmission Initiatives

NSP-Minnesota expects to use existing power plants, power purchases, CIP options, new generation facilities and expansion of existing power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. NSP-Minnesota also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

NSP System Resource Plans — In November 2012, the MPUC issued an order on NSP-Minnesota's resource plan and required additional filings to determine the next resources needed for the NSP System generating capacity. In December 2012, NSP-Minnesota filed its information indicating an estimated need of 150 MW in 2017 and increasing to 440 MW by 2019, with the size and timing to be determined by the MPUC. A competitive acquisition process is anticipated to commence in March 2013 and result in the selection of a developer or developers by the MPUC in the fourth quarter of 2013. See additional discussion within the Prairie Island Nuclear EPU section below.

CapX2020 — In 2009, the MPUC granted CONs to construct one 230 KV electric transmission line and three 345 KV electric transmission lines as part of the CapX2020 project. The estimated cost of the four major transmission projects is $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total cost. The remainder of the costs will be borne by other utilities in the upper Midwest. These cost estimates will be updated as the projects progress.

Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 345 KV transmission line
In May 2012, the MPUC issued a route permit for the Minnesota portion of the project. Two parties have filed an appeal with the Minnesota Court of Appeals against the MPUC's route permit decision. A decision by the Court is anticipated in mid-2013. In May 2012, the PSCW issued a CPCN for the Wisconsin portion of the project. Subsequent legal challenges to the PSCW's order by intervenors were unsuccessful, thereby rendering the PSCW's decision final. Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2015.

Monticello, Minn. to Fargo, N.D. 345 KV transmission line
In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Monticello, Minn. to Fargo, N.D. project was placed in service. The MPUC issued a route permit for the Minnesota portion of the St. Cloud, Minn. to Fargo, N.D. section in June 2011. The NDPSC granted a CPCN in January 2011 and a certificate of corridor compatibility and route permit for the portion of the line in North Dakota in September 2012. In January 2013, construction started on the project in North Dakota.

Brookings County, S.D. to Hampton, Minn. 345 KV transmission line
The MPUC route permit approvals for the Minnesota segments were obtained in 2010 and 2011. In June 2011, the SDPUC approved a facility permit for the South Dakota segment. In December 2011, MISO granted the final approval of the project as a MVP. In May 2012, construction started on the project in Minnesota.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line
The Bemidji, Minn. to Grand Rapids, Minn. line was placed in service in September 2012.

Black Dog Repowering CON — In November 2012, the MPUC approved the termination of the Black Dog Repowering CON proceeding.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants. The event at the nuclear generating plant in Fukushima, Japan in 2011 could impact the NRC's deliberations on NSP-Minnesota's Monticello power uprate request and could also result in additional regulation, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force that has developed recommendations on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures and licensing processes. In July 2011, the task force released its recommendations in a written report which recommends actions to enhance U.S. nuclear generating plant readiness to safely manage severe events.

In March 2012, the NRC issued three orders and a request for additional information to all licensees. The orders included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The request for additional information included requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. NSP-Minnesota expects that complying with these requirements will cost approximately $35 to $50 million at the Monticello and Prairie Island plants. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance to meet the orders is expected to begin in the second quarter of 2015 with all units expected to be fully compliant by December 2016. Portions of the work that fall under the requests for additional information are expected to be completed by 2018. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

LLW Disposal — LLW from NSP-Minnesota's Monticello and Prairie Island nuclear plants is currently disposed at the Clive facility located in Utah. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility.

Nuclear Geologic Repository - Yucca Mountain Project

In 2002, the U.S. Congress designated Yucca Mountain, Nevada as the first deep geologic repository. In 2008, the DOE submitted an application to construct a deep geologic repository at this site to the NRC. In 2010, the DOE announced its intention to stop the Yucca Mountain project and requested the NRC approve the withdrawal of the application. In June 2010, the ASLB issued a ruling that the DOE could not withdraw the Yucca Mountain application. In September 2011, the NRC announced that it was evenly divided on whether to take the affirmative action of overturning or upholding the ASLB decision. Because the NRC could not reach a decision, an order was issued instructing that information associated with the ASLB adjudication should be preserved. The ASLB complied and the proceeding has been suspended.

The DOE's decision and the resulting stoppage of the NRC's review has prompted multiple legal challenges, including the DOE's authority to stop the project and withdraw the application, the DOE's authority to continue to collect the nuclear waste fund fee and the NRC's authority to stop their review of the DOE's application. The utility industry, including Xcel Energy, Inc. and NSP-Minnesota, are represented in these challenges by the NEI. Currently, only the challenges to set the nuclear waste fund fee collection rate to zero and seeking the NRC to complete their review remain active and decisions are expected from the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in 2013.

At the time that the DOE decided to stop the Yucca Mountain project and withdraw the application, the Secretary of Energy convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. In January 2012, the Blue Ribbon Commission report was issued. The report provided numerous policy recommendations that are being considered by the Secretary of Energy. In January 2013, the DOE provided its report to Congress relative to their plans to implement the Blue Ribbon Commission's recommendations including the required legislative changes and authorizations required. The report also announced the Obama Administration's intent to make a pilot consolidated interim storage facility available in 2021, a larger consolidated interim storage facility available in 2025 and a deep geologic repository available in 2048.

Nuclear Spent Fuel Storage
NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. As of Dec. 31, 2012, there were 29 casks loaded and stored at the Prairie Island plant and 10 canisters loaded and stored at the Monticello plant. An additional 35 casks for Prairie Island and 20 canisters for Monticello have been authorized by the State of Minnesota. This currently authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the renewed operating licenses in 2030 for Monticello, 2033 for Prairie Island Unit 1, and 2034 for Prairie Island Unit 2.

PFS — The eight partners of PFS, including NSP-Minnesota, have agreed to dissolve the LLC. PFS filed a letter with the NRC in December 2012 requesting to terminate the PFS license effective immediately. PFS will be taking the appropriate actions to dissolve the LLC in 2013.

NRC Waste Confidence Decision (WCD) — In June 2012, the D.C. Circuit issued a ruling to vacate and remand the NRC's WCD. The WCD assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. The D.C. Circuit remanded the WCD to the NRC and directed it to prepare an environmental impact statement (EIS) if there are significant impacts or an environmental assessment to support a finding of no significant impact. In September 2012, the NRC Commissioners directed the NRC Staff to develop an EIS and a revised WCD and rule on the temporary storage of spent nuclear fuel. The EIS and rule are to be completed within 24 months. NSP-Minnesota does not believe that there will be an immediate impact on operations at the Prairie Island or Monticello nuclear generating plants.

See Notes 11 and 12 to the consolidated financial statements for further discussion regarding nuclear related items.

Nuclear Plant Power Uprates and Life Extension

Life Extensions — In 2006, the NRC renewed the Monticello operating license allowing the plant to operate until 2030. In 2011, the NRC issued renewed operating licenses for Prairie Island Units 1 and 2, allowing Unit 1 to operate until 2033 and Unit 2 until 2034.

Prairie Island Independent Spent Fuel Storage Installation (ISFSI) License Renewal — The current license to operate an ISFSI at Prairie Island expires in October 2013. An application to renew the ISFSI license for an additional 40 years until 2053 was submitted by NSP-Minnesota to the NRC in October 2011. In August 2012, the Prairie Island Indian Community (PIIC) petitioned to intervene and filed contentions with the NRC. In September 2012, the NRC named an ASLB to review the PIIC's request to intervene and contentions. In December 2012, the ASLB found that the PIIC had standing to intervene and admitted three of the seven contentions put forward by the PIIC. The ASLB will establish a schedule for the hearing which should be completed by mid-2014. As Prairie Island met the NRC's criteria for timely renewal by submitting its ISFSI license renewal application more than two years in advance of the expiration of the ISFSI's current license, it will be allowed to continue to operate under the current license until the NRC has rendered a decision on the license renewal application.

Prairie Island Nuclear Plant EPU — In 2009, the MPUC granted NSP-Minnesota a CON for an EPU project at the Prairie Island nuclear generating plant. The total estimated cost of the EPU was $294 million, of which approximately $77.6 million has been incurred, including AFUDC of approximately $13.3 million. Subsequently, NSP-Minnesota filed a resource plan update and a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In December 2012, the MPUC voted unanimously that no party had shown cause to prevent termination of the EPU CON. The MPUC is expected to issue an order terminating the EPU CON in the first half of 2013.

NSP-Minnesota plans to address recovery of incurred costs in the next rate case for each of the NSP-Minnesota jurisdictions and to file a request with the FERC for approval to recover a portion of the costs from NSP-Wisconsin through the Interchange Agreement. NSP-Wisconsin plans to seek cost recovery in a future rate case. Based on the outcome of the MPUC decision, EPU costs incurred to date were compared to the discounted value of the estimated future rate recovery based on past jurisdictional precedent, resulting in a $10.1 million pretax charge in December 2012 which is included in O&M expense.

Monticello Nuclear Plant EPU — In 2008, NSP-Minnesota filed for both state and federal approvals of an EPU of approximately 71 MW for NSP-Minnesota's Monticello nuclear generating plant. The MPUC approved the CON for the EPU in 2008. The license amendment filing was placed on hold by the NRC Staff to address concerns raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. In September 2012, NSP-Minnesota made a supplemental filing to the NRC to address the containment accident pressure concern, as part of its application to amend the operating license to allow the power uprate. NSP-Minnesota expects to receive approval of the EPU project by the NRC in the second half of 2013. NSP-Minnesota is planning to complete implementation of the equipment changes needed to support the Monticello life extension and EPU projects in the planned spring 2013 refueling outage.

Overall, NSP-Minnesota is nearing completion of its life cycle management and EPU project at the Monticello nuclear generating plant to help ensure continued safe and reliable operation through 2030, and to provide additional capacity of approximately 71 MW. As a result of the licensing delays discussed above, as well as engineering design changes and emergent work discovered during implementation, both the cost and the projected in-service date exceed initial estimates, consistent with experience of other nuclear plant life extension and uprate projects. In addition, despite the cancellation of the EPU project at the Prairie Island nuclear generating plant, NSP-Minnesota is implementing life cycle management improvements at the Prairie Island facilities to help ensure their safe and reliable operation through 2034. The major capital investments for these activities at the Monticello and Prairie Island nuclear generating plants are expected to be completed in the years 2013 through 2017, with combined forecasted capital costs in that period of approximately $500 million.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

	Coal*		Nuclear		Natural Gas		Weighted Average Owned
NSP System Generating Plants	**Cost**	**Percent**	**Cost**	**Percent**	**Cost**	**Percent**	**Fuel Cost**
2012	$ 2.13	47%	$ 0.90	42%	$ 4.21	11%	$ 1.88
2011	2.06	55	0.89	40	6.56	5	1.82
2010	1.89	51	0.83	42	6.29	7	1.73

* Includes refuse-derived fuel and wood

See Item 1A for further discussion of fuel supply and costs.

Fuel Sources

Coal — The NSP System normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2012 and 2011 were approximately 39 and 48 days usage, respectively. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. During 2012 and 2011, coal requirements for the NSP System's major coal-fired generating plants were approximately 7.2 million tons and 9.5 million tons, respectively. The estimated coal requirements for 2013 are approximately 8.6 million tons.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 97 percent of their coal requirements in 2013, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of 100 and 80 percent of their coal requirements in 2013 and 2014, respectively. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Nuclear — To operate NSP-Minnesota's nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2018 and approximately 67 percent of the requirements for 2019 through 2025.
- Current contracts for conversion services cover 100 percent of the requirements through 2020 and approximately 67 percent of the requirements for 2021 through 2025.
- Current enrichment service contracts cover 99.7 percent of the requirements through 2022 and approximately 84 percent of the requirements for 2023 through 2025.

Fabrication services for Monticello and Prairie Island are 100 percent committed through 2025 and 2014, respectively. A contract for fuel fabrication services for Prairie Island is currently being negotiated for 2015 and beyond.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the total fuel requirements of its nuclear generating plants. Some exposure to spot market price volatility will remain due to index-based pricing structures contained in certain supply contracts.

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies and associated transportation and storage services for power plants are procured under contracts with various terms to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. These transportation rates are subject to revision based upon FERC approval of changes in the timing or amount of allowable cost recovery by providers. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2012 and 2011, the NSP System did not have any commitments related to gas supply contracts; however, commitments related to gas transportation and storage contracts were approximately $384 million and $462 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2013 to 2028.

The NSP System also has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

The NSP System's renewable energy portfolio includes wind, hydroelectric, biomass, and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2012, the NSP System was in compliance with mandated RPSs, which require generation from renewable resources of 18 percent and 8.89 percent of NSP-Minnesota and NSP-Wisconsin electric retail sales, respectively. Renewable energy comprised 22.0 percent and 19.7 percent of the NSP System's total owned and purchased energy for 2012 and 2011, respectively. Wind energy comprised 11.9 percent and 9.4 percent of the total owned and purchased energy on the NSP System for 2012 and 2011, respectively. Hydroelectric energy comprised 7.0 percent and 7.5 percent of the total owned and purchased energy on the NSP System for 2012 and 2011, respectively. Biomass and solar power comprised approximately 3.1 percent and 2.8 percent of renewable energy for 2012 and 2011, respectively.

The NSP System also offers customer-focused renewable energy initiatives. Windsource®, one of the nation's largest voluntary renewable energy programs, allows customers in Minnesota, Wisconsin, and Michigan to purchase a portion or all of their electricity from renewable sources. Approximately 24,000 and 23,000 customers purchased 184,000 MWh and 177,000 MWh of electricity under the Windsource program in 2012 and 2011, respectively. Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards® program. Over 561 PV systems with approximately 6.7 MW of aggregate capacity and over 300 PV systems with approximately 3 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2012 and 2011, respectively.

Wind — The NSP System acquires the majority of its wind energy from PPAs with wind farm owners, primarily in Southwestern Minnesota. The NSP System currently has more than 100 of these agreements in place, with facilities ranging in size from under 1 MW to more than 200 MW. In 2012, the NSP System began purchasing wind from three new projects, which provided approximately 266 MW of capacity. The largest of these projects, the Prairie Rose Wind Project began commercial operations in December 2012 and the NSP System will purchase the entire output from this 200 MW project. In addition to receiving purchased wind energy under these agreements, the NSP System also typically receives wind RECs, which are used to meet state renewable resource requirements. The average cost per MWh of wind energy under these contracts was approximately $41 and $39 for 2012 and 2011, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state specific renewable resource requirements, and the year of contract execution. Generally, contracts executed in 2012 benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to the anticipated expiration of the Federal PTCs in 2012. In January 2013, the Federal PTC was extended through 2013.

The NSP System also owns and operates two wind farms. The 101 MW Grand Meadow Wind Farm and the 201 MW Nobles Wind Farm began generating electricity in 2008 and 2010, respectively. Collectively, the NSP System had over 1,870 MW and over 1,600 MW of wind energy on its system at the end of 2012 and 2011, respectively.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and PPAs. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide 274 MW of capacity. For most of 2012, there were nine PPAs in place which provided approximately 37 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 850 MW of generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. See Item 7A for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of NSP-Minnesota, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of NSP-Minnesota's activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 10 to the accompanying consolidated financial statements for discussion of other regulatory matters.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — The FERC issued Order 1000 adopting new requirements for transmission planning, cost allocation and development to be effective prospectively. The requirements for transmission planning and cost allocation were addressed by revisions to the MISO Tariff for NSP-Minnesota as discussed below in MISO Transmission Pricing.

In 2012, Minnesota's Governor signed legislation that preserves the rights of incumbent utilities to construct and own transmission interconnected to their systems. This legislation is similar to the legislation previously passed in North Dakota and South Dakota. Therefore, Order 1000 is expected to have limited impacts on future transmission development and ownership in the NSP System in Minnesota, North Dakota and South Dakota.

ATC vs. Xcel Energy Services Inc. and MISO (Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. Transmission Line) — In October 2012, American Transmission Company LLC (ATC) filed a complaint against MISO, Xcel Energy Services Inc., NSP-Minnesota and NSP-Wisconsin, alleging that, under the legal principles set forth in the July 2012 FERC ruling in the La Crosse to Madison transmission line complaint filed by Xcel Energy Services Inc. on behalf of its subsidiary NSP-Wisconsin against ATC, that the FERC should determine that MISO should have designated the Hampton to Rochester to La Crosse CapX2020 line and the La Crosse to Madison line as a single facility under the MISO Transmission Owners Agreement and Tariff. Thus, ATC should have been designated as the owner of the La Crosse to Madison line portion of the purported single facility. Xcel Energy filed an answer seeking dismissal of the ATC complaint in October 2012. On Feb. 4, 2013, the FERC issued an order denying the ATC complaint. The FERC found that MISO properly applied its planning process and that Hampton to La Crosse and the La Crosse to Madison lines are separate. Therefore, MISO's prior ownership decisions stand.

ARCs — In 2009, the FERC adopted rules requiring RTOs to allow ARCs to offer demand response aggregation services to end-use customers of large utilities unless the relevant state regulatory agency prohibited the operation of ARCs. Under MISO's proposed tariff revisions, ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Minnesota. In 2010, MISO requested its compliance tariff revisions be effective in June 2010, and the MPUC, NDPSC, SDPUC, PSCW and MPSC all issued orders prohibiting, or temporarily prohibiting, the operation of ARCs in their states.

In December 2011, the FERC issued orders denying rehearing of the rules and approving most aspects of the MISO compliance filing. The FERC retained the rules allowing state regulatory authorities to prohibit ARCs within their state. NSP-Minnesota is exploring a pilot program that would expand existing retail CIP services to more fully interact with the MISO market. The most recent filing in this open docket was in November 2012.

Electric Transmission Rate Regulation — The FERC regulates the rates and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control of their electric transmission assets for the sale of electric transmission services to an RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO RTO. Each RTO separately files regional transmission tariff rates for approval by the FERC. All members within that RTO are then subjected to those rates.

MISO Transmission Pricing — The MISO Tariff presently provides for different allocation methods for the costs of new transmission investments: some lower voltage projects are fully allocated to loads near the project vicinity, and other reliability projects are allocated 20 percent regionally and 80 percent to local loads. If a project qualifies as a MVP, the costs would be fully allocated to all loads in the MISO region. MVP eligibility is generally obtained for higher voltage (345 KV and higher) projects expected to provide multiple purposes, such as improved reliability, reduced congestion, transmission for renewable energy, and load serving. Certain parties have appealed the FERC MVP tariff orders to the U.S. Court of Appeals for the Seventh Circuit.

In its Order 1000 compliance filing in October 2012, MISO proposed that all future reliability projects be fully allocated to the zones in which the project is located (rather than allocating costs more broadly) while MVP projects would continue to be eligible for regional cost allocation. FERC action is anticipated in 2013. The NSP System has certain new transmission facilities for which other customers in MISO contribute to cost recovery. Likewise, the NSP System also pays a share of the costs of projects constructed by other transmission owning entities. The transmission revenues received by the NSP System from MISO, and the transmission charges paid to MISO, associated with projects subject to regional cost allocation could be significant in future periods.

RSG Charges — The MISO tariff charges certain market participants a real-time RSG charge, which is designed to ensure that any generator scheduled or dispatched by MISO will receive no less than its offer price for start-up, no-load and incremental energy. In August 2010, the FERC issued two orders relating to RSG charge exemptions and the allocation of the RSG costs among MISO participants. In recent RSG filings, MISO has proposed, and the FERC has accepted, allocating a greater portion of the RSG costs related to resources committed for voltage and local reliability requirements to the market participants with the loads that benefit from such commitments. NSP-Minnesota is permitted to recover the RSG costs through FCA mechanisms approved by the regulators in each jurisdiction. Certain of the FERC's orders remain pending on rehearing, and appeals of the FERC orders to the U.S. Court of Appeals for the D.C. Circuit have been held in abeyance, pending the FERC's disposition of rehearing requests.

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2012	2011	2010
Electric sales (Millions of KWh)			
Residential	10,377	10,448	10,414
Large commercial and industrial	9,302	9,750	9,739
Small commercial and industrial	15,478	15,439	15,450
Public authorities and other	264	260	266
Total retail	35,421	35,897	35,869
Sales for resale	1,625	1,711	2,234
Total energy sold	37,046	37,608	38,103
Number of customers at end of period			
Residential	1,252,589	1,245,413	1,240,509
Large commercial and industrial	496	500	502
Small commercial and industrial	151,978	151,144	150,392
Public authorities and other	6,699	6,470	6,291
Total retail	1,411,762	1,403,527	1,397,694
Wholesale	15	17	13
Total customers	1,411,777	1,403,544	1,397,707
Electric revenues (Thousands of Dollars)			
Residential	$ 1,165,413	$ 1,140,598	$ 1,095,862
Large commercial and industrial	632,831	660,083	627,774
Small commercial and industrial	1,324,989	1,270,757	1,240,979
Public authorities and other	34,444	34,211	33,329
Total retail	3,157,677	3,105,649	2,997,944
Wholesale	42,748	47,316	79,555
Interchange revenues from NSP-Wisconsin	449,958	440,519	416,076
Other electric revenues	192,146	179,144	131,140
Total electric revenues	$ 3,842,529	$ 3,772,628	$ 3,624,715
KWh sales per retail customer	25,090	25,576	25,663
Revenue per retail customer	$ 2,237	$ 2,213	$ 2,145
Residential revenue per KWh	11.23¢	10.92¢	10.52¢
Large commercial and industrial revenue per KWh	6.80	6.77	6.45
Small commercial and industrial revenue per KWh	8.56	8.23	8.03
Wholesale revenue per KWh	2.63	2.76	3.56

Energy Source Statistics

	Year Ended Dec. 31					
	2012		2011		2010	
NSP System	**Millions of KWh**	**Percent of Generation**	**Millions of KWh**	**Percent of Generation**	**Millions of KWh**	**Percent of Generation**
Coal	16,023	35%	20,131	44%	19,579	42%
Nuclear	13,231	29	13,332	29	14,628	31
Natural Gas	6,200	13	3,016	7	3,887	8
Wind (a)	5,443	12	4,312	9	3,760	8
Hydroelectric	3,193	7	3,444	8	3,487	7
Other (b)	1,617	4	1,453	3	1,494	4
Total	45,707	100%	45,688	100%	46,835	100%
Owned generation	31,365	69%	31,668	69%	33,758	72%
Purchased generation	14,342	31	14,020	31	13,077	28
Total	45,707	100%	45,688	100%	46,835	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. The NSP System uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of NSP-Minnesota are continued volatility in natural gas market prices, uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential and small commercial and industrial (C&I) customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2012, average annual sales to the typical residential customer declined from 107 MMBtu per year to 86 MMBtu per year, and to the typical small C&I customer declined from 376 MMBtu per year to 348 MMBtu per year, on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost recovery mechanisms, high prices can encourage further efficiency efforts by customers.

The Pipeline and Hazardous Materials Safety Administration

***Pipeline Safety Act* —** The Pipeline Safety, Regulatory Certainty, and Job Creation Act, signed into law in January 2012 (Pipeline Safety Act) requires, among other things, additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) will require operators to re-confirm the maximum allowable operating pressure. This process could cause temporary or permanent limitations on throughput for affected pipelines. In addition, the Pipeline Safety Act requires PHMSA to issue reports and develop new regulations, addressing a variety of subjects, including: requiring use of automatic or remote-controlled shut-off valves in certain circumstances; requiring testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2 million for a related series of violations. While NSP-Minnesota cannot predict the ultimate impact Pipeline Safety Act will have on its costs, operations or financial results, NSP-Minnesota is taking actions that are intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's retail natural gas operations are regulated by the MPUC and the NDPSC within their respective states. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting customers' future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is subject to the DOT, the Minnesota Office of Pipeline Safety, the NDPSC and the SDPUC for pipeline safety compliance, including pipeline facilities used in electric utility operations for fuel deliveries.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation service and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

Minnesota state law requires utilities to invest 0.5 percent of their state natural gas revenues in CIP. These costs are recovered through customer base rates and an annual cost-recovery mechanism for the CIP expenditures.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 732,135 MMBtu, which occurred on Jan. 19, 2012, and 751,985 MMBtu, which occurred on Jan. 20, 2011.

NSP-Minnesota purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 590,698 MMBtu per day. In addition, NSP-Minnesota contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 32 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 31 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. The 2009-2010, 2010-2011, 2011-2012, and 2012-2013 entitlement levels are pending MPUC action.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota's regulated retail natural gas distribution business:

2012	$	4.41
2011		5.25
2010		5.43

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2013 through 2033.