division of energy resources
Minnesota Department of Commerce

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December 18, 2012

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

RE: Comments of the Minnesota Department of Commerce, Division of Energy Resources
Docket No. E002/RP-10-825

Dear Dr. Haar:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (DOC or the Department) in the following matter:

Northern States Power Company d/b/a Xcel Energy Application for
Resource Plan Approval 2011-2025

The Department 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 is available to answer any questions the Commission may have.

Sincerely,

/s/ CHRISTOPHER T. DAVIS
Rates Analyst

CTD/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE,
DIVISION OF ENERGY RESOURCES

DOCKET NO. E002/RP-10-825

I. INTRODUCTION

On August 2, 2010 Northern States Power Company d/b/a Xcel Energy submitted is 2011-2025 Integrated Resource Plan.

The following interveners submitted written comments to the Commission:

- Calpine Corporation,
- Campus Beyond Coal (University of Minnesota-Twin Cities),
- City of Mankato,
- Department of Commerce,
- enXco,
- Environmental Intervenors,
- Greater Mankato Growth,
- Minnesota Chamber of Commerce,
- Minnesota Solar Companies and Organizations,
- Prairie Island Indian Community, and
- University of Minnesota.

Individuals providing comments in Xcel's resource plans included:

- Carol Overland,
- Alan Muller, and

- Dustin Dension, Applied Energy Innovations.

In addition, the Commission received a large number of public comments, most of them supporting greater use of solar, other renewables, and conservation in Xcel's resource mix. These comments included a letter with 624 names of Xcel customers supporting increased use of solar energy, letters from 610 customers supporting replacing Sherco 1 and 2 with solar, and a letter from approximately 10 student organizations supporting increased use of solar and other clean energy.

On October 25, 2012, the Commission met to consider this matter.

On November 30, 2012 the Minnesota Public Utilities Commission (Commission) issued its Order Establishing Procedural Schedules and Filing Requirements in this docket. Order Point 1 of the Commission's Order states:

> 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.

Below are the comments of the Department explaining the results of our additional analysis and our recommendations for how to proceed in this matter.

II. ADDITIONAL MODELING AND RECOMMENDATIONS OF THE DEPARTMENT

A. RELIABILITY

Due to the interest in the issue of electric reliability the Department includes a discussion of the national, regional, and state regulatory framework for ensuring electric reliability in Attachment 1, as well as a discussion of how planning reserve margins are calculated in Attachment 2. These attachments were previously included in the Department's November 30, 2012 *Comments* in Docket No. E017/RP-10-623. They are included here in case participants in this docket have not seen this information and thus may benefit.

B. IRP ACTION PLANS

In order for a utility to act, it requires knowledge of the size, type,[1] and timing of the actions it will implement. Thus, Minnesota Rules for integrated resource plans require the utility to provide an action plan. Specifically, Minnesota 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.

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 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.

Overall, the Department's modeling of Xcel's system under the assumption that the Company will not proceed with the Extended Power Uprate at Prairie Island (PI EPU) resulted in a least-cost base case expansion plan which includes the addition of 300 MW of intermediate capacity in the form of a natural gas fired combined cycle (CC) plant. However, as discussed in further detail in the next section, these modeling results and other reasons lead the Department to recommend that the Commission modify Xcel's approved competitive resource acquisition process, as spelled out in Xcel's August 28, 2006 comments in Docket No. E002/RP-04-1752, to allow bidders, including Xcel, to submit proposals for both peaking and intermediate facilities in the competitive resource acquisition process.

The first reason for this recommended approach is that the Department's modeling indicates that the type of resource chosen by the model changes with relatively small changes in assumptions. While resource planning results are often fairly robust such that changes in modeling do not change the general size, type and timing under various assumptions, the modeling results in this

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[1] Types of supply-side resources include peaking, intermediate, baseload, and wind. Typically, types of resources are categorized by their capacity factor, the percent of time they operate. The most common type of a peaking plant is a combustion turbine (CT) generating plant. An intermediate plant is defined in these comments as a combined cycle (CC), gas-fired plant. However, gas-fired CTs and wind together can be combined to provide the characteristics of an intermediate plant. That is, gas-fired CC facilities or gas-fired CT facilities with wind or other energy sources are designed to operate more frequently than peaking facilities, but less than baseload facilities. Thus, to be clear, the Department defines "intermediate" facilities as gas-fired CC facilities or gas-fired CT facilities with wind or other energy sources.

case indicate that the specifics of what is bid into the competitive acquisition process may lead to a different least-cost plan than the use of generic resources. The second reason for this recommended approach is that the Department believes that allowing both types of facilities to submit bids would impose cost discipline on the process and potentially result in lower prices for ratepayers by allowing a greater spectrum of potential bidders. Finally, the Department notes that the Commission-approved competitive resource acquisition process includes an evaluation subject to the discipline of an administrative law judge. As a result, the Department concludes that this public evaluation should occur in a timely manner and thus there should be no significant delays that could result in reliability issues due to any complexities that might arise from considering bids from different types of resources.

The Department discusses the first two reasons further below.

C. MODELING

1. Discussion of Inputs

The Department's modeling started with the same model that was used for the Department's June 12, 2012 *Comments* in this docket. The Department implemented the following changes to its June 12, 2012 base case:

- eliminated the Prairie Island Extended Power Uprate (EPU)—implemented using Strategist commands provided by Xcel;[2]
- deferred the retirement date of the Key City peaking units from 2012 to 2016—based upon discussions with Xcel;
- deferred the retirement date of the Granite peaking units from 2012 to 2016—based upon discussions with Xcel;
- brought French Island 3 peaking unit back on-line in 2014 and maintained on-line through Xcel's resource plan period—based upon discussions with Xcel;
- reduced the size of the intermediate (combined cycle) expansion unit from 400 MW to 300 MW—changed to experiment with a smaller combined cycle (CC) project than was used in prior comments;
- changed the heat rate of the CC expansion unit—degraded due to smaller size of the unit;
- changed the CO_2 cost implementation date from 2012 to 2017—per Commission Order; and
- restored the discount rate to the input used by Xcel in its original CN petition.[3]

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[2] Data to implement this structure was taken from the Company's response to Department Information Request No. 31 in Docket No. E002/CN-08-509 and Department Information Request No. 158 in Docket No. E002/RP-10-825. Also, for completeness the Department ran through Strategist scenarios where the uprate did take place. However, the results were not instructive and thus they are not discussed but details are available in Attachment 3.

[3] The Department's June 12, 2012 *Comments* changed the Company's discount rate to a weighted average of all rate of return in all jurisdictions. However, during discovery for these comments the Department learned that several other inputs also needed to be changed to be consistent with the new discount rate. It soon became apparent that tracking down and implementing all the necessary changes would be too difficult and would most likely not

In addition to the base case, the Department ran scenarios that included:

- removing all CO_2 pricing;
- forcing wind units to comply with the renewable energy standard; and
- forcing an additional 100 MW of load management.

The Department ran each scenario through the same contingencies as in our original resource plan comments. However, the Department added one additional contingency. The new contingency reduced the capital cost for peaking and intermediate expansion units by 15 percent. This contingency was run to reflect the potential for cost reductions due to use of brownfield sites by both Xcel and Calpine in future resource acquisition proceedings.[4]

Since the purpose of these 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, the Department' comments focus on the least-cost expansion plan selected by Strategist. Further details are provided in Attachment 3.

2. Discussion of Outputs

The Department's base case expansion plan is shown in Table 1 below.

influence the Department's final recommendation. Therefore, the Department restored the Company's original discount rate.

[4] Xcel's expansion units' capital costs in the Company's previous modeling assume the use of greenfield sites.

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	-	-	-	-

Table 1 shows the size, type and timing of the least-cost expansion plan under base case assumptions. The Department also examined the second through tenth most cost-effective plans under base case conditions and discovered that Strategist is, in essence, considering two basic plans in the 2017 to 2019 time frame for providing an intermediate resource. One plan usually involves adding two combustion turbine (CT or peaking) units totaling 378 MW; usually accompanied by a 200 MW wind unit. The second plan involves adding one CT unit and one combined cycle (CC or intermediate) unit. In this plan the typical case is that no wind units are added between 2017 and 2019. Both types of plans add varying combinations of CC, CT, and wind units in the 2020 to 2026 time frame. Under base case conditions only two contingencies do not observe the "CT plus wind" or "CT plus CC" rule: CO_2 ramp down and wholesale market available.

The Department's analysis focuses on resources that must be added from 2017 to 2019 because planning for the acquisition of these resources is required now. The Department's analysis indicates that additional resources will be required in 2021. However, that date is far enough in the future that resource acquisition plans can be delayed until the Company's next resource plan.

In terms of total peaking and intermediate plant added in the 2017 to 2019 time frame, Strategist consistently selects either: a) 378 MW of peaking facilities (two CT plan) plus 200 MW of wind or b) 492 MW of intermediate and peaking facilities (one CT and one CC plan) of natural gas fired capacity. These expansion plans are shown by the data presented in Table 2 below. Under all four scenarios the vast majority of contingencies add 378 MW or 492 MW of peaking and

[5] 200 MW of nameplate wind capacity currently translates into 26 MW of accredited capacity.

intermediate plants. Of interest is that 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 actually accelerated to 2016.

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

While Strategist is consistent in selecting the size and timing of the capacity to add (see Table 2), the specific resource plan it chooses to provide the intermediate plant is sensitive to the input assumptions. The Department's base case analysis indicates a slight preference for Xcel to procure an intermediate unit in 2017 and a peaking unit in 2019, with the intermediate plant capabilities being provided by a natural gas fired combined cycle plant. However, this preference changes with small changes in input assumptions. This change in the least-cost plan selected is shown in Table 3 below, which provides the total combined cycle capacity added.

Reviewing the Base Case results shown in Table 3, when coal prices are raised, the combined cycle unit drops out of the expansion plan. The most likely explanation is that more energy is now needed from expansion units (rather than from Xcel's existing coal units), wind is added to supply that energy, and then CTs are added to cover capacity deficits. Thus under this assumption the combined cycle plant is replaced by wind and peaking units. For this analysis the Department assumed a wind cost of $65 per MWh in the base case.

Similarly, when natural gas prices are increased, less energy from gas is cost-effective, wind is added to supply the missing energy and then CTs are added to cover capacity deficits. Also, when wind prices decrease, wind displaces natural gas (and potentially coal) for energy production and then CTs are added to cover capacity deficits. Similar results can be seen from a review of the Minnesota Renewable Energy Standard (RES) mandate scenario (which adds significant amounts of wind in the future to comply with Minnesota's RES mandate) in Table 3.

The results of the 100 MW of load management scenario show a strong preference not to add any CC units in 2017-2019. The results are the opposite for the No CO_2 cost scenario—adding a CC unit is generally preferred unless wind or natural gas prices are very low.

In summary, Table 3 demonstrates that the quantity of CC capacity selected for the expansion plan between 2017 and 2019 is highly sensitive to the many key input assumptions.

One interesting result of the 100 MW of load management scenario is that increasing load management serves to increase the overall level of CO_2 emissions in certain contingencies; see Attachment 3 for further details. Most likely this result can be explained by the fact that increasing load management does not change the overall energy need, but decreases capacity requirements. The lower need for capacity enables Strategist to substitute a less fuel efficient CT unit for a CC unit; the CT unit has a lower accredited capacity and a lower overall capital cost. The decrease in capital costs for the expansion unit enabled by load management, in some instances, outweighs the increase in variable costs due to the CT unit's worse heat rate. Thus, under some circumstances load management can actually increase system emissions.

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	-

The Department also reviewed the top ten plans (as ranked in terms of present value of social costs, or PVSC).[6] The results show that the top ten plans are within $6 million PVSC of each other, a relatively small amount. Seven of the top ten plans have one CC unit and one CT unit added in 2017 to 2019. The other three plans all show two CT units added between 2017 and 2019 along with 200 MW of wind. The "CT plus CC" plan is least cost while the best "CT only" plan is ranked third, costing about $1.5 million PVSC more than the least cost plan.

Similar analysis could be done for the other three scenarios —No EPU plus no CO_2 costs, No EPU plus RES compliance, and No EPU plus 100 MW of additional load management—showing that the top ten plans contain a mixture of variations on the two CTs plus wind plan and the CT plus CC plan.

In short, all 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. Therefore, the Department recommends that the Commission order Xcel to pursue up to 500 MW of natural gas fired capacity to be on-line between 2017 and 2019. Due to the unstable nature of the overall results, the specific type of capacity (peaking or intermediate) would be determined from analysis of specific bids.

The Department notes that, under base case conditions, the two CT plan is accompanied by 200 MW of wind in the 2017 to 2019 time frame. Of the 16 contingencies where two CT units were selected, 14 also selected 200 MW of wind. However, of the 19 contingencies where a CC unit was selected 18 did not select any wind in 2017 to 2019. Therefore, it appears at this time that if CT units are eventually selected, wind additions would also be necessary. However, due to the scheduled expiration of the federal wind production tax credit on December 31, 2012, it is difficult to assess whether the Department's assumption of a wind cost of $65 per MWh is reasonable. Further, Xcel has argued that wind must be $50 per MWh for it to be cost-effective. When modeling the bids that will be submitted in March, 2013, the Department will take into account the likelihood that cost-effective wind will not be available in the specified time frame. For example, one approach would be to assume a higher wind cost in the base case. Another way would be to not allow the model to choose wind during a specified period.

D. USING COMPETITION TO GET THE BEST VALUE FOR RATEPAYERS

The Midwest Independent System Operator's (MISO)'s new regional structure with the MISO footprint divided into seven Planning Resource Zones[7] limits the geographic scope of potential competitors due to costs of moving resources between zones. The Department discussed this structure with utilities and understands that, in effect, the Planning Resource Zone structure places limits on how far a resource can be located from load and still be economic. If Xcel does

[6] PVSC is equal to an expansion plan's present value of revenue requirements plus the present value of the expansion plan's environmental costs.
[7]

not provide a bid for a combined cycle unit, the Department is concerned that there may not be a reasonable amount of competitive bids if only combined cycle units are allowed to bid. The Department concludes that the best way to ensure adequate competition is to allow the Company to bid its preferred peaking resources, against whatever resources potential competitors, such as Calpine, are willing to bid.

E. RECOMMENDATION

The Department recommends that 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 time frame. The specific type of capacity should be determined based upon actual bids submitted in the competitive resource acquisition proceeding.

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Docket No. E002/RP-10-825

ATTACHMENT NO. 1

Electric Utility Reliability Regulatory Framework

Minnesota's electric utilities have a complex regulatory framework at the federal, regional, and state levels. The Department summarizes these interrelated regulatory processes below. Based on our review of the electric utilities' regulatory framework, the Department concludes that Minnesota Statutes give the Commission broad authority such that the Commission can require investments even in instances where the utility has not proposed to make adequate infrastructure investments.

I. FERC

The Federal Energy Regulatory Commission (FERC) is an independent agency of the federal government that regulates the interstate transmission of electricity, natural gas, and oil. FERC oversees the North American Electric Reliability Corporation (NERC), which is the Electric Reliability Organization (ERO) for the U.S. FERC has given NERC the legal authority to develop and enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable.

2. NERC

NERC was originally established in 1968 to promote bulk electrical system (BES) reliability. Historically, NERC connected the various industry participants through a voluntary council. That changed with the passage of the U.S. Energy Policy Act of 2005, which called for the creation of an international ERO. NERC became the international ERO under the Energy Policy Act of2005.

"Electricity reliability organization" refers to NERC's role. It is a generic nan1e given by the U.S. Congress to the independent entity given the authority to develop and enforce mandatory standards for the reliable operation and planning of the BES throughout North America, as called for in the U.S. Energy Policy Act of 2005. NERC was designated as this "electricity reliability organization" by FERC.

NERC defines the reliability of the BES in terms of two basic and functional aspects:

- adequacy-The ability of the BES to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- security-The ability of the BES to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies.[1]

By statute, NERC is required to develop mandatory and enforceable reliability standards that are subject to FERC review and approval. Once approved, the reliability standards may be enforced by NERC, subject to FERC oversight, or by the FERC independently. For example, NERC standard TPL-001-0 which establishes:

[1] For decades, NERC and the bulk power industry defined system "security" as the ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber- attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

- category A-system intact,
- category B-loss of a single element (N-1), and
- category C-loss of 2 or more elements (N-2).

Category A refers to the ability of the electric system to provide firm service if there are no contingencies, meaning that the system remains intact. For category B, utility planners must show that they Call continue to provide service to firm customers with one contingency (major outage). For category C, utility planners must show that, under multiple contingencies, they call provide firm service with some planned or controlled interruption of electric supply to these customers in certain areas without impacting the overall reliability of the interconnected transmission systems.

On Aprill9, 2007, FERC accepted delegation agreements between NERC and eight Regional Entities, discussed below. Thus, NERC delegates its authority to eight regional entities to monitor and enforce compliance with reliability standards for the BES.

Membership of the eight regional entities, comes from all segments of the electric industry:

- investor-owned utilities;
- federal power agencies;
- rural electric cooperatives;
- state, municipal and provincial utilities;
- independent power producers;
- power marketers; and
- end-use customers.

These entities account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California, Mexico.

The regional entities have several duties. In terms of reliability, the regional entities have delegated authorities and responsibilities, as approved by FERC, to enforce NERC and regional reliability standards and perform other standards-related actions assigned by NERC. NERC oversees the regional entities in this role to ensure consistency of delegated functions across North America, while allowing for an appropriate degree of flexibility to accommodate regional differences.

3. MRO

The Midwest Reliability Organization (MRO) is a non-profit organization based in Minnesota that is the regional entity responsible for ensuring the reliability of the BES in the north central region of North America.[2] MRO is one of the eight regional entities in North America operating under delegated authority in the United States and Canada. MRO began operations on January I, 2005, as the successor to the Mid-continent Area Power Pool (MAPP), which was formed in 1965.

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[2] MRO's region includes the provinces of Saskatchewan and Manitoba, the states of Iowa, Minnesota, Nebraska, and North Dakota; the majority of South Dakota, and Wisconsin; and a small portion of Montana.

In terms of reliability, MRO is responsible for:

- developing and implementing reliability standards;
- enforcing compliance with those standards;
- providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity; and
- providing an appeals and dispute resolution process.

In terms of activities, the primary focus of MRO is:

- assessing compliance with reliability standards on entities that own, operate or use the BES;
- performing assessments of the BES; and
- technical analysis of matters impacting the reliability of the BES.

4. MISO

The Midwest Independent Transmission System Operator, Inc. (MISO) operates a real-time energy market and has 93,600 miles of transmission lines under its direction. MISO is subject to regulation by the FERC and is a Regional Transmission Organization (RTO). As an RTO, MISO assures consumers of unbiased regional grid management and open access to the transmission facilities under MISO's functional supervision. MISO engages in several activities supporting reliability analysis:

1. To help ensure ongoing, safe and reliable energy delivery, each year MISO performs studies to evaluate current market conditions to forecast future planning environments.
2. MISO collects generator performance data through the PowerGADS web application.
3. MISO uses the data to calculate the forced outage rates used in loss of load expectation (LOLE) Studies and to determine each generator's Unforced Capacity (UCAP) value and resource pooled class averages.
4. A LOLE study[3] is performed annually to set the minimum planning reserve margin (PRM) for the upcoming planning year and provide a nine year PRM forecast. LOLE studies consider multiple risk factors including planned maintenance outages, unplanned or forced outages, load forecast uncertainty and transmission congestion. MISO may determine separate planning reserve margins for different zones if there are system constraints that impede system wide reserve sharing. Also, MISO will defer to state authority in cases where a state establishes its own PRM. How PRMs operate is discussed further in the *Planning Reserves Margin* section below.

In addition to being an RTO, MISO is responsible for regional system reliability, which includes bulk transmission reliability and power supply reliability, sunm1arized as follows:

[3] In accordance with the MISO tariff, the reliability objective of a LOLE study is to determine a minimum planning reserve margin that would result in the MISO system experiencing a less than one day loss of load event every ten years.

- Bulk Transmission Reliability-MISO has the responsibility to approve planned critical transmission facility outages, apply transmission loading relief procedures, order redispatch of generation, and order curtailment of transactions and/or load.
- Power Supply Reliability- MISO has the responsibility to ensure that adequate capacity is available or committed to meet demand and reserve obligations within the market footprint. Within the MISO structure there are balancing authorities (BAs). BAs have the responsibility for real-time control performance. MISO monitors BA performance and directs the BAs to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the grid in jeopardy.

MISO handles reliability through what is referred to as "module E." Under module E, capacity resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate an unforced capacity value (UCAP) for the resource. A market participant can use capacity resources up to their UCAP values to contribute towards the resource adequacy requirement to the extent the market participant is willing to subject the capacity resource to the MISO's must-offer commitment and meet all other resource adequacy obligations. A market participant may convert UCAP amounts that are subject to the must offer commitment to planning resource credits (PRCs). Resource adequacy at any particular Commercial Pricing Node (CPNode) is achieved for a given month if the load serving entity has at least as many PRCs as its forecasted peak demand for that month plus its PRM.

5. RTO versus ISO

A regional transmission organization (RTO) in the United States is an organization that is responsible for moving electricity over large interstate areas. Like a transmission system operator (TSO), an RTO coordinates, controls and monitors an electricity transmission grid that is larger with much higher voltages than the typical power company's distribution grid. TSOs in Europe cross state and provincial borders like RTOs.

An Independent System Operator (ISO) is an organization formed at the direction or recommendation of FERC. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system, usually within a single US State, but sometimes encompassing multiple states. RTOs typically perform the same functions as ISOs, but cover a larger geographic area.

As an ISO, MISO is a non-profit organization that combines the transmission facilities of several transmission owners into a single transmission system to move energy over long distances at a single lower price than the combined charges of each utility that may be located between the buyer and seller. The ISO provides non-discriminatory service, and must be independent of the transmission owners and the customers who use its system.

As an RTO, MISO provides non-discriminatory access to the transmission network; however, MISO is required to meet specific FERC regulations that deal with transmission planning and expansion for an entire region, the use of energy markets to deal with system congestion, of power users and owners. RTOs offer regional wholesale electric transmission services under one tariff.

6. Minnesota Public Utilities Commission

Minnesota Statutes §216B.04 provides Commission authority over the standard of service:

> Every public utility shall furnish safe, adequate, efficient, and reasonable service; provided that service shall be deemed adequate if made so within 90 days after a person requests service. Upon application by a public utility, and for good cause shown, the commission may extend the period for not to exceed another 90 days.

Minnesota Statutes §216B.79 provides Commission authority over reliability and preventive maintenance activities:

> The Commission may order public utilities to make adequate infrastructure investments and undertake sufficient preventative maintenance with regard to generation, transmission, and distribution facilities. The Commission's authority under this section also applies to any transmission company that owns or operates electric transmission lines in Minnesota.

Minnesota Statutes §216B.029 subd. 1 provides the Commission authority over reliability standards for distribution utilities:

> (a) The commission and each cooperative electric association and municipal utility shall adopt standards for safety, reliability, and service quality for distribution utilities. Standards for cooperative electric associations and municipal utilities should be as consistent as possible with the commission standards.
>
> (b) Reliability standards must be based on the system average interruption frequency index, system average interruption duration index, and customer average interruption duration index measurement indices. Service quality standards must specify, if technically and administratively feasible:
>
> (1) average call center response time;
> (2) customer disconnection rate;
> (3) meter-reading frequency;
> (4) complaint resolution response time;
> (5) service extension request response time;
> (6) recording of service and circuit interrupter data;
> (7) summary reporting;
> (8) historical reliability performance reporting;
> (9) notices of interruptions of bulk power supply facilities and other interruptions of power; and
> (10) customer complaints.
>
> (c) Minimum performance standards developed under this section must treat similarly situated distribution systems

> similarly and recognize differing characteristics of system design and hardware.
>
> (d) Electric distribution utilities shall comply with all applicable governmental and industry standards required for the safety, design, construction, and operation of electric distribution facilities, including section 326B.35.

The Department's view is that Minnesota Statutes give the Commission wide authority such that the Commission can require investments even in instances where the utility has not proposed to make adequate infrastructure investments.

Docket No. E002/RP-10-825

ATTACHMENT NO. 2

Planning Reserve Margins

1. *Overall Purpose of Planning Reserve Margins*

Since electricity production must equal demand on an instantaneous basis and electricity cannot be stored in an economic manner, it is critical to the continued reliable operation of the integrated electrical system to have generation in reserve in case a generation facility in operation fails. This additional reserve is called the planning reserve margin. In addition, the transmission system is generally designed with redundancies to allow for rerouting of power in case of a failure of lines (known as "N-1" generally).

2. *How Planning Reserve Margins Used to Work*

Previously, the planning reserve margin was set at a utility's peak load plus a 15 percent generation reserve:

Utility's total capacity obligation= peak load* 1.15

This calculation was easy to perform. Under this system, there was no adjustment to the amount of resources a utility had (installed capacity) even if a utility had more outages than average.

The overall planning reserve margin might be increased, but such adjustments rarely happened. For example, the Mid-continent Area Power Pool (MAPP) had the same 15 percent reserve ratio for decades. Two examples of the MAPP reliability calculation method are shown below. The point of the exercise here is to compare the forced outage rate in the two examples with the capacity requirement. In Example A, utility B has a 10 percent forced outage rate; in Example B utility B has a higher forced outage rate (15 percent). However, utility B's capacity requirement (and ultimate Capacity surplus/deficit) does not change. In economic terms, the costs of poor unit reliability are socialized across the regional footprint rather than being attributed to the utility with poor unit reliability.

Table A1: Former Reliability Calculation Method

Example A: 10% Forced outage rate for Utility B				
	Utility A	**Utility B**	**System**	**Unit**
Outage rate	0%	10%	6.70%	%
Load	1,000	2,000	3,000	MW
Planning Reserve Margin	15.00%	15.00%	15.00%	%
Capacity Requirement	1,150	2,300	3,450	MW
Resources (installed capacity)	1,200	2,400	3,600	MW
Capacity Surplus/Deficit	50	100	150	MW

Example B: 15% Forced outage rate for Utility B				
	Utility A	**Utility B**	**System**	**Unit**
Outage rate	0%	15%	10.00%	%
Load	1,000	2,000	3,000	MW
Planning Reserve Margin	15.00%	15.00%	15.00%	%
Capacity Requirement	1,150	2,300	3,450	MW
Resources (installed capacity)	1,200	2,400	3,600	MW
Capacity Surplus/Deficit	50	100	150	MW

3. How Planning Reserve Margins Work Now

Reliability organizations such as the Midwest Independent Transmission System Operator, Inc. (MISO) recognize that not all generation is created equally in that not all generating units can be equally counted on to be available to run when the capacity of the system is reached. As a result, MISO now assesses the performance of each utility's system based on recent performance of the utility's generating units. Thus, the calculation of the capacity requirement for each utility is more complex since MISO uses several factors to determine the amount of accredited capacity, based on both utility-specific data and system-wide data.

First, to reflect the reliability of each generation plant, MISO annually calculates a factor called "XEFORd" which is a percentage reflecting forced outages of each generating unit, based on performance during the past three years. MISO uses this factor to "derate" generating units, or reduce the amount of "dependable capacity" of the generating units based on this recent performance. The reduced "dependable capacity" is called "Unforced Capacity" or UCAP, since this capacity has not been in a forced outage in the past three years:

Table A2: Defining Unforced Capacity

$ICAP \times (1 - XEFORd_{IGEN}) = UCAP$ Where: • ICAP is installed generation capacity (expressed in MW)[4] • $XEFORd_{IGEN}$ is the equivalent forced outage rate of the generation, when there is demand on the unit to run, excluding events that MISO determines to be outside management control (expressed as a percentage) • UCAP is the amount of generation capacity that can reasonably be relied on from the generation unit. (expressed in MW)

In the above equation the term $(1 - XEFORd_{IGEN})$ is the derating factor that reflects the reduced reliability of the installed generation. UCAP then is the amount of generation that can reasonably be counted on to run when needed. Higher forced outage rates or $XEFORd_{IGEN}$ factors result in lower UCAP levels, meaning that the utility's generation isn't as reliable to meet its load.

Second, to reflect the ability of the MISO system to back up generation outages, MISO calculates a series of numbers. The Loss of Load Expectation (LOLE) on a MISO-wide basis indicates "a minimum planning reserve margin that would result in the MISO system experiencing a less than one day loss of load event every ten years." For example, in 2012, MISO's analysis showed that the system would achieve this reliability level when the amount of installed capacity available is 1.167 times that of the MISO system coincident peak. This 16.7% planning reserve margin is called PRM_{IGEN} and is analogous to the 15% planning reserve margin used previously in Figure 4. However, PRM_{IGEN} is revised annually by MISO to reflect expected loss of load probabilities, whereas the previous planning reserve margin rarely changed.

In addition, because there is diversity within the MISO system (given that different utilities peak at different times) MISO uses a diversity factor to reduce the reserve margin for individual peaks of load-serving entities (LSEs). For example, in 2012, MISO calculated a 4.61% diversity factor, which resulted in an individual LSE reserve level of 11.3% (16.7%- 4.61%).

MISO also calculates a system-wide level of forced outages, which is called the System Average XEFORd (which, again, is adjusted to remove events that are outside of management control). In 2012, MISO calculated the system forced outages to be 6.77%. MISO essentially uses this factor to "derate" the ability of the MISO system to meet the planning reserve margin PRM_{IGEN}. This adjusted planning reserve margin is called $PRM_{UCAPXEFORd}$ and reflects the ability of the system to meet the $PRM_{IGENXEFORd}$ by incorporating the effects on reliability of system outages. In Table A3 below:

[4] NOTE: ICAP (Installed Capacity) represents the generating capacity that is physically on the ground and has a defined value determined by the lesser of a test result or the amount of transmission interconnection.

Table A3: UCAP Reliability Calculation Method

Example A: 10% Forced outage rate for Utility B					
	Utility A	**Utility B**	**MISO**	**Unit**	**Notes**
Outage rate	0.0%	10.0%	6.7%	%	Historical outage rate
Load	1,000	2,000	3,000	MW	
Resources $_{ICAP}$	1,200	2,400	3,600	MW	
(1 – Outage Rate)	100%	90%	93%	%	
Resources $_{UCAP}$	1,200	2,160	3,360	MW	= (1 - Outage Rate) * Resources $_{ICAP}$
PRM $_{ICAP}$			15.0%	%	From LOLE Study
PRM $_{UCAP}$	7.33%	7.33%	7.33%	%	Reliability equivalent to PRM $_{ICAP}$
Resource Requirement $_{ICAP}$			3,450	MW	= Load * (1+ PRM $_{ICAP}$)
Resource Requirement $_{UCAP}$	1,073.3	2,146.7	3,220.0	MW	= Load * (1-Outage$_{MISO}$) * (1+ PRM $_{ICAP}$) or = Load * (1 + PRM $_{UCAP}$)
Surplus/Deficit	126.7	13.3			

Example B: 15% Forced outage rate for Utility B					
	Utility A	**Utility B**	**MISO**	**Unit**	**Notes**
Outage rate	0.0%	15.0%	10.0%	%	Historical outage rate
Load	1,000	2,000	3,000	MW	
Resources $_{ICAP}$	1,200	2,400	3,600	MW	
(1 – Outage Rate)	100%	85%	90%	%	
Resources $_{UCAP}$	1,200	2,040	3,240	MW	= (1 - Outage Rate) * Resources $_{ICAP}$
PRM $_{ICAP}$			17%	%	From LOLE Study
PRM $_{UCAP}$	5.30%	5.30%	5.30%	%	Reliability equivalent to PRM $_{ICAP}$
Resource Requirement $_{ICAP}$			3,510	MW	= Load * (1+ PRM $_{ICAP}$)
Resource Requirement $_{UCAP}$	1,053	2,106	3,159	MW	= Load * (1-Outage$_{MISO}$) * (1+ PRM $_{ICAP}$) or = Load * (1 + PRM $_{UCAP}$)
Surplus/Deficit	147	(66)		MW	

The equation for the UCAP Planning Reserve Margin adjusted for system outage rates ($PRM_{UPCAPXEFORd}$) is shown in Table A4.

Table A4: UCAP Planning Reserve Margin

$$(1\text{-System Average}_{XEFORd}) * (1+PRM_{IGENXEFORd}) = (1 + PRM_{UPCAPXEFORd})$$

Where:

- $(1\text{-System Average}_{XEFORd})$ is the derate factor for the system to reflect outages
- $1+ PRM_{IGENXEFORd}$ is the total installed generation factor adjusted for outages
- $1 + PRM_{UPCAPXEFORd}$ is the total dependable generation factor adjusted for outages

In sum, the UCAP method first derates specific utility generation units based on recent outages, and then adjusts the utilities' requirements based on the ability of the system to provide backup resources for outages.

4. *Differences in UCAP method compared to previous method:*

The results of the UCAP method, compared to the previous method are that:

- the capacity requirements, overall, better reflect the reliability of the system by incorporating recent outages and hence the ability of the existing system to provide reliable service;
- utilities with more reliable generation are given more credit relative to utilities with less reliable generation and thus have higher surpluses or lower deficits; and
- utilities with less reliable generation are given relatively (and likely absolutely) less credit and thus have lower surpluses or higher deficits.

The table below compares the UCAP method to the old planning reserve margin of 15% ("Pre-UCAP"). The comparison assumes MISO's UCAP planning reserve margins from Figure 6 (15% reserve margin with 6.7% system outage rate and 17% reserve margin for 10% system outage rate). In general, UCAP holds utilities accountable by rewarding utilities with low outage rates and penalizing utilities with high outage rates. UCAP also reflects that systems with more outages are less reliable overall than was previously recognized (negative values indicate lower values for UCAP method that existed prior to UCAP). Table A5 below provides a comparison of the previous method to the UCAP method.

Table A5: Comparison of Methods

10% Forced outage rate for Utility B	Utility A	Utility B	MISO	Unit	NOTES
Outage rate	0%	10%	6.70%	%	
Load	1,000	2,000	3,000	MW	
Resources $_{ICAP}$	1,200	2,400	3,600	MW	
Difference: Dependable capacity	0.0	(240.0)	(240.0)	MW	(UCAP - Pre UCAP)
Difference: Resource requirement	(76.7)	(153.3)	(230.0)	MW	(UCAP - Pre UCAP)
Difference: Surplus/Deficit	76.7	(86.7)	(150.0)	MW	(UCAP - Pre UCAP)

15% Forced outage rate for Utility B	Utility A	Utility B	MISO	Unit	NOTES
Outage rate	0%	15%	10.00%	%	
Load	1,000	2,000	3,000	MW	
Resources $_{ICAP}$	1,200	2,400	3,600	MW	
Difference: Dependable capacity	0.0	(360.0)	(360.0)	MW	(UCAP - Pre UCAP)
Difference: Resource requirement	(97.0)	(194.0)	(291.0)	MW	(UCAP - Pre UCAP)
Difference: Surplus/Deficit	97.0	(166.0)	(150.0)	MW	(UCAP - Pre UCAP)

Docket No. E002/RP-10-825

ATTACHMENT NO. 3

NOTE: The following 3 pages provide the total MW added between 2017 and 2019 for scenarios without an Extended Power Uprate at Prairie Island.

Total Gas MW 2017-'19	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
Base Case	492	492	492	378
$34 CO2	378	492	378	378
$9 CO2	492	492	492	378
CO2 Delayed	492	492	492	378
CO2 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
Average	441	479	456	362
Max	591	567	591	492
Min	303	303	378	189

Total CT MW 2017-'19	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
Base Case	189	189	189	378
$34 CO2	378	189	378	378
$9 CO2	189	189	189	378
CO2 Delayed	189	189	189	378
CO2 Reduction	189	189	189	-
High Capital Cost +10%	189	567	189	378
Low Capital Cost -10%	378	189	378	378
Low Externalities	189	189	189	378
Coal - 20%	189	189	189	378
Coal - 10%	189	189	189	378
Coal + 10%	378	189	189	378
Coal + 20%	378	189	378	378
Natural Gas - $1.50	189	567	189	378
Natural Gas - $1.00	189	189	189	378
Natural Gas - $0.50	189	189	189	378
Natural Gas + $0.50	378	189	378	378
Natural Gas + $1.00	378	189	378	378
Natural Gas + $1.50	378	189	378	378
Natural Gas + $2.00	378	189	189	378
Natural Gas + $2.50	378	189	189	-
Natural Gas No Growth	189	567	189	-
Wholesale Market On	378	378	378	189
$35 Wind	378	378	189	-
$40 Wind	378	378	378	378
$45 Wind	378	378	378	378
$50 Wind	378	378	378	378
$55 Wind	378	189	378	378
$60 Wind	378	189	378	378
$70 Wind	189	189	189	-
$75 Wind	189	189	189	-
$80 Wind	189	189	189	-
Wind High Credit (20%)	189	189	189	378
Wind Low Credit (10%)	189	189	189	378
Forecast, Mid-High	-	-	378	189
Forecast, High	567	567	567	-
Minus 15 Pct CT CC	189	189	189	378
Average	278	252	268	284
Max	567	567	567	378
Min	-	-	189	-

Total CC MW 2017-'19	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
Base Case	303	303	303	-
$34 CO2	-	303	-	-
$9 CO2	303	303	303	-
CO2 Delayed	303	303	303	-
CO2 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	-
Average	163	227	188	79
Max	402	303	402	402
Min	-	-	-	-

NOTE: The following 2 pages provide the present value of societal costs (PVSC) for each scenario and each contingency along with comparisons to the base case PVSC for scenarios without an Extended Power Uprate at Prairie Island.

PVSC ($,000) 2012-'26	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
No EPU	$ 52,252,515	$ 47,100,119	$ 52,253,391	$ 52,160,872
$34 CO2	$ 54,887,027	$ 47,100,119	$ 54,882,211	$ 54,818,216
$9 CO2	$ 49,490,455	$ 47,100,119	$ 49,560,503	$ 49,434,718
CO2 Delayed	$ 51,350,851	$ 47,100,119	$ 51,349,363	$ 51,259,588
CO2 Reduction	$ 53,034,159	$ 49,080,153	$ 53,032,187	$ 52,971,836
High Capital Cost +10%	$ 52,387,515	$ 47,229,935	$ 52,385,915	$ 52,318,680
Low Capital Cost -10%	$ 52,060,715	$ 46,968,931	$ 52,117,139	$ 51,994,340
Low Externalities	$ 51,896,403	$ 47,100,119	$ 51,897,279	$ 51,804,724
Coal - 20%	$ 51,090,547	$ 45,931,461	$ 51,098,837	$ 51,005,418
Coal - 10%	$ 51,674,131	$ 46,516,007	$ 51,676,803	$ 51,583,824
Coal + 10%	$ 52,825,607	$ 47,683,989	$ 52,827,827	$ 52,735,828
Coal + 20%	$ 53,391,743	$ 48,267,395	$ 53,394,671	$ 53,305,348
Natural Gas - $1.50	$ 51,243,795	$ 46,155,849	$ 51,308,139	$ 51,183,154
Natural Gas - $1.00	$ 51,610,271	$ 46,479,683	$ 51,652,767	$ 51,550,056
Natural Gas - $0.50	$ 51,940,871	$ 46,791,177	$ 51,960,867	$ 51,862,644
Natural Gas + $0.50	$ 52,539,591	$ 47,409,543	$ 52,541,395	$ 52,455,076
Natural Gas + $1.00	$ 52,823,831	$ 47,719,109	$ 52,822,719	$ 52,747,324
Natural Gas + $1.50	$ 53,106,907	$ 48,029,637	$ 53,103,551	$ 53,035,920
Natural Gas + $2.00	$ 53,389,815	$ 48,339,183	$ 53,384,979	$ 53,314,084
Natural Gas + $2.50	$ 53,665,615	$ 48,649,361	$ 53,639,867	$ 53,572,328
Natural Gas No Growth	$ 49,427,165	$ 44,797,433	$ 49,625,689	$ 49,347,634
Wholesale Market On	$ 51,148,073	$ 46,637,685	$ 51,300,683	$ 51,135,414
$35 Wind	$ 47,525,263	$ 43,363,561	$ 47,591,599	$ 47,433,254
$40 Wind	$ 51,745,131	$ 46,899,927	$ 51,838,935	$ 51,666,408
$45 Wind	$ 51,867,747	$ 46,994,433	$ 51,961,551	$ 51,789,020
$50 Wind	$ 51,990,367	$ 47,061,053	$ 52,076,683	$ 51,911,632
$55 Wind	$ 52,109,415	$ 47,100,119	$ 52,176,747	$ 52,034,220
$60 Wind	$ 52,187,291	$ 47,100,119	$ 52,231,167	$ 52,118,204
$70 Wind	$ 52,256,327	$ 47,100,119	$ 52,253,391	$ 52,199,904
$75 Wind	$ 52,256,327	$ 47,100,119	$ 52,253,391	$ 52,199,904
$80 Wind	$ 52,256,327	$ 47,100,119	$ 52,253,391	$ 52,199,904
Wind High Credit (20%)	$ 52,252,515	$ 47,100,119	$ 52,253,391	$ 52,160,872
Wind Low Credit (10%)	$ 52,256,327	$ 47,100,119	$ 52,253,391	$ 52,186,980
Forecast, Mid-High	$ 52,368,499	$ 47,240,001	$ 52,391,595	$ 52,291,648
Forecast, High	$ 52,527,875	$ 47,370,153	$ 52,540,911	$ 52,461,416
Minus 15 Pct CT CC	$ 52,078,283	$ 46,926,501	$ 52,079,155	$ 52,012,140
MAX	$ 54,887,027	$ 49,080,153	$ 54,882,211	$ 54,818,216
AVERAGE	$ 52,023,915	$ 47,051,917	$ 52,054,084	$ 51,950,011
MIN	$ 47,525,263	$ 43,363,561	$ 47,591,599	$ 47,433,254

PVSC ($,000) 2012-'26 Diff. from Base Case, same contingency.	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
No EPU	$ -	$ (5,152,396)	$ 876	$ (91,643)
$34 CO2	$ -	$ (7,786,908)	$ (4,816)	$ (68,811)
$9 CO2	$ -	$ (2,390,336)	$ 70,048	$ (55,737)
CO2 Delayed	$ -	$ (4,250,732)	$ (1,488)	$ (91,263)
CO2 Reduction	$ -	$ (3,954,006)	$ (1,972)	$ (62,323)
High Capital Cost +10%	$ -	$ (5,157,580)	$ (1,600)	$ (68,835)
Low Capital Cost -10%	$ -	$ (5,091,784)	$ 56,424	$ (66,375)
Low Externalities	$ -	$ (4,796,284)	$ 876	$ (91,679)
Coal - 20%	$ -	$ (5,159,086)	$ 8,290	$ (85,129)
Coal - 10%	$ -	$ (5,158,124)	$ 2,672	$ (90,307)
Coal + 10%	$ -	$ (5,141,618)	$ 2,220	$ (89,779)
Coal + 20%	$ -	$ (5,124,348)	$ 2,928	$ (86,395)
Natural Gas - $1.50	$ -	$ (5,087,946)	$ 64,344	$ (60,641)
Natural Gas - $1.00	$ -	$ (5,130,588)	$ 42,496	$ (60,215)
Natural Gas - $0.50	$ -	$ (5,149,694)	$ 19,996	$ (78,227)
Natural Gas + $0.50	$ -	$ (5,130,048)	$ 1,804	$ (84,515)
Natural Gas + $1.00	$ -	$ (5,104,722)	$ (1,112)	$ (76,507)
Natural Gas + $1.50	$ -	$ (5,077,270)	$ (3,356)	$ (70,987)
Natural Gas + $2.00	$ -	$ (5,050,632)	$ (4,836)	$ (75,731)
Natural Gas + $2.50	$ -	$ (5,016,254)	$ (25,748)	$ (93,287)
Natural Gas No Growth	$ -	$ (4,629,732)	$ 198,524	$ (79,531)
Wholesale Market On	$ -	$ (4,510,388)	$ 152,610	$ (12,659)
$35 Wind	$ -	$ (4,161,702)	$ 66,336	$ (92,009)
$40 Wind	$ -	$ (4,845,204)	$ 93,804	$ (78,723)
$45 Wind	$ -	$ (4,873,314)	$ 93,804	$ (78,727)
$50 Wind	$ -	$ (4,929,314)	$ 86,316	$ (78,735)
$55 Wind	$ -	$ (5,009,296)	$ 67,332	$ (75,195)
$60 Wind	$ -	$ (5,087,172)	$ 43,876	$ (69,087)
$70 Wind	$ -	$ (5,156,208)	$ (2,936)	$ (56,423)
$75 Wind	$ -	$ (5,156,208)	$ (2,936)	$ (56,423)
$80 Wind	$ -	$ (5,156,208)	$ (2,936)	$ (56,423)
Wind High Credit (20%)	$ -	$ (5,152,396)	$ 876	$ (91,643)
Wind Low Credit (10%)	$ -	$ (5,156,208)	$ (2,936)	$ (69,347)
Forecast, Mid-High	$ -	$ (5,128,498)	$ 23,096	$ (76,851)
Forecast, High	$ -	$ (5,157,722)	$ 13,036	$ (66,459)
MAX	$ -	$ (2,390,336)	$ 198,524	$ (12,659)
AVERAGE	$ -	$ (4,971,998)	$ 30,169	$ (73,903)
MIN	$ -	$ (7,786,908)	$ (25,748)	$ (93,287)

NOTE: The following 8 pages provide the total units added during the planning period for each scenario and each contingency along with comparisons to the base case total units added.

Units added (2012-'26)	No EPU							
	Scenario 1				Change from Scenario 1 Base			
Contingency	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	4	4	-	4				
$34 CO2	7	2	-	6	3	(2)	-	2
$9 CO2	6	3	-	-	2	(1)	-	(4)
CO2 Delayed	4	4	-	4	-	-	-	-
CO2 Reduction	2	5	-	10	(2)	1	-	6
High Capital Cost +10%	6	3	-	-	2	(1)	-	(4)
Low Capital Cost -10%	7	2	-	6	3	(2)	-	2
Low Externalities	4	4	-	4	-	-	-	-
Coal - 20%	6	3	-	-	2	(1)	-	(4)
Coal - 10%	6	3	-	-	2	(1)	-	(4)
Coal + 10%	7	2	-	6	3	(2)	-	2
Coal + 20%	7	2	-	6	3	(2)	-	2
Natural Gas - $1.50	6	3	-	-	2	(1)	-	(4)
Natural Gas - $1.00	6	3	-	-	2	(1)	-	(4)
Natural Gas - $0.50	6	3	-	-	2	(1)	-	(4)
Natural Gas + $0.50	7	2	-	6	3	(2)	-	2
Natural Gas + $1.00	7	2	-	6	3	(2)	-	2
Natural Gas + $1.50	7	2	-	6	3	(2)	-	2
Natural Gas + $2.00	7	2	-	6	3	(2)	-	2
Natural Gas + $2.50	7	2	-	8	3	(2)	-	4
Natural Gas No Growth	6	2	-	-	2	(2)	-	(4)
Wholesale Market On	7	2	-	-	3	(2)	-	(4)
$35 Wind	7	2	-	10	3	(2)	-	6
$40 Wind	7	2	-	10	3	(2)	-	6
$45 Wind	7	2	-	10	3	(2)	-	6
$50 Wind	7	2	-	10	3	(2)	-	6
$55 Wind	7	2	-	8	3	(2)	-	4
$60 Wind	7	2	-	6	3	(2)	-	2
$70 Wind	6	3	-	-	2	(1)	-	(4)
$75 Wind	6	3	-	-	2	(1)	-	(4)
$80 Wind	6	3	-	-	2	(1)	-	(4)
Wind High Credit (20%)	4	4	-	4	-	-	-	-
Wind Low Credit (10%)	6	3	-	-	2	(1)	-	(4)
Forecast, Mid-High	5	4	-	2	1	-	-	(2)
Forecast, High	6	4	-	-	2	-	-	(4)

Contingency
No EPU
$34 CO2
$9 CO2
CO2 Delayed
CO2 Reduction
High Capital Cost +10%
Low Capital Cost -10%
Low Externalities
Coal - 20%
Coal - 10%
Coal + 10%
Coal + 20%
Natural Gas - $1.50
Natural Gas - $1.00
Natural Gas - $0.50
Natural Gas + $0.50
Natural Gas + $1.00
Natural Gas + $1.50
Natural Gas + $2.00
Natural Gas + $2.50
Natural Gas No Growth
Wholesale Market On
$35 Wind
$40 Wind
$45 Wind
$50 Wind
$55 Wind
$60 Wind
$70 Wind
$75 Wind
$80 Wind
Wind High Credit (20%)
Wind Low Credit (10%)
Forecast, Mid-High
Forecast, High

Units added (2012-'26)	No EPU No CO2							
	Scenario 2				Change from Scen 1b Base			
Contingency	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	6	3	-	-				
$34 CO2	6	3	-	-	-	-	-	-
$9 CO2	6	3	-	-	-	-	-	-
CO2 Delayed	6	3	-	-	-	-	-	-
CO2 Reduction	2	5	-	10	(4)	2	-	10
High Capital Cost +10%	6	3	-	-	-	-	-	-
Low Capital Cost -10%	6	3	-	-	-	-	-	-
Low Externalities	6	3	-	-	-	-	-	-
Coal - 20%	6	3	-	-	-	-	-	-
Coal - 10%	6	3	-	-	-	-	-	-
Coal + 10%	6	3	-	-	-	-	-	-
Coal + 20%	6	3	-	-	-	-	-	-
Natural Gas - $1.50	6	3	-	-	-	-	-	-
Natural Gas - $1.00	6	3	-	-	-	-	-	-
Natural Gas - $0.50	6	3	-	-	-	-	-	-
Natural Gas + $0.50	6	3	-	-	-	-	-	-
Natural Gas + $1.00	6	3	-	-	-	-	-	-
Natural Gas + $1.50	6	3	-	-	-	-	-	-
Natural Gas + $2.00	6	3	-	-	-	-	-	-
Natural Gas + $2.50	6	3	-	-	-	-	-	-
Natural Gas No Growth	6	3	-	-	-	-	-	-
Wholesale Market On	7	2	-	-	1	(1)	-	-
$35 Wind	7	2	-	10	1	(1)	-	10
$40 Wind	7	2	-	10	1	(1)	-	10
$45 Wind	7	2	-	6	1	(1)	-	6
$50 Wind	7	2	-	6	1	(1)	-	6
$55 Wind	6	3	-	-	-	-	-	-
$60 Wind	6	3	-	-	-	-	-	-
$70 Wind	6	3	-	-	-	-	-	-
$75 Wind	6	3	-	-	-	-	-	-
$80 Wind	6	3	-	-	-	-	-	-
Wind High Credit (20%)	6	3	-	-	-	-	-	-
Wind Low Credit (10%)	6	3	-	-	-	-	-	-
Forecast, Mid-High	7	3	-	-	1	-	-	-
Forecast, High	6	4	-	-	-	1	-	-

Contingency	Scenario 2 MINUS Scenario 1			
	Peaker	Intermediate	Baseload	Wind
No EPU	2	(1)	-	(4)
$34 CO2	(1)	1	-	(6)
$9 CO2	-	-	-	-
CO2 Delayed	2	(1)	-	(4)
CO2 Reduction	-	-	-	-
High Capital Cost +10%	-	-	-	-
Low Capital Cost -10%	(1)	1	-	(6)
Low Externalities	2	(1)	-	(4)
Coal - 20%	-	-	-	-
Coal - 10%	-	-	-	-
Coal + 10%	(1)	1	-	(6)
Coal + 20%	(1)	1	-	(6)
Natural Gas - $1.50	-	-	-	-
Natural Gas - $1.00	-	-	-	-
Natural Gas - $0.50	-	-	-	-
Natural Gas + $0.50	(1)	1	-	(6)
Natural Gas + $1.00	(1)	1	-	(6)
Natural Gas + $1.50	(1)	1	-	(6)
Natural Gas + $2.00	(1)	1	-	(6)
Natural Gas + $2.50	(1)	1	-	(8)
Natural Gas No Growth	-	1	-	-
Wholesale Market On	-	-	-	-
$35 Wind	-	-	-	-
$40 Wind	-	-	-	-
$45 Wind	-	-	-	(4)
$50 Wind	-	-	-	(4)
$55 Wind	(1)	1	-	(8)
$60 Wind	(1)	1	-	(6)
$70 Wind	-	-	-	-
$75 Wind	-	-	-	-
$80 Wind	-	-	-	-
Wind High Credit (20%)	2	(1)	-	(4)
Wind Low Credit (10%)	-	-	-	-
Forecast, Mid-High				
Forecast, High				

Units added (2012-'26) Contingency	No EPU Wind Mandate							
	Scenario 3				Change from Scenario 16 Base			
	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	4	4	-	-				
$34 CO2	7	2	-	2	3	(2)	-	2
$9 CO2	4	4	-	-	-	-	-	-
CO2 Delayed	4	4	-	-	-	-	-	-
CO2 Reduction	2	5	-	8	(2)	1	-	8
High Capital Cost +10%	4	4	-	-	-	-	-	-
Low Capital Cost -10%	7	2	-	2	3	(2)	-	2
Low Externalities	4	4	-	-	-	-	-	-
Coal - 20%	4	4	-	-	-	-	-	-
Coal - 10%	4	4	-	-	-	-	-	-
Coal + 10%	4	4	-	-	-	-	-	-
Coal + 20%	7	2	-	2	3	(2)	-	2
Natural Gas - $1.50	4	4	-	-	-	-	-	-
Natural Gas - $1.00	4	4	-	-	-	-	-	-
Natural Gas - $0.50	4	4	-	-	-	-	-	-
Natural Gas + $0.50	7	2	-	2	3	(2)	-	2
Natural Gas + $1.00	7	2	-	2	3	(2)	-	2
Natural Gas + $1.50	7	2	-	2	3	(2)	-	2
Natural Gas + $2.00	5	3	-	8	1	(1)	-	8
Natural Gas + $2.50	5	3	-	8	1	(1)	-	8
Natural Gas No Growth	4	3	-	-	-	(1)	-	-
Wholesale Market On	7	2	-	-	3	(2)	-	-
$35 Wind	5	3	-	10	1	(1)	-	10
$40 Wind	5	3	-	10	1	(1)	-	10
$45 Wind	5	3	-	10	1	(1)	-	10
$50 Wind	5	3	-	8	1	(1)	-	8
$55 Wind	5	3	-	8	1	(1)	-	8
$60 Wind	7	2	-	2	3	(2)	-	2
$70 Wind	4	4	-	-	-	-	-	-
$75 Wind	4	4	-	-	-	-	-	-
$80 Wind	4	4	-	-	-	-	-	-
Wind High Credit (20%)	4	4	-	-	-	-	-	-
Wind Low Credit (10%)	4	4	-	-	-	-	-	-
Forecast, Mid-High	8	2	-	2	4	(2)	-	2
Forecast, High	9	2	-	-	5	(2)	-	-

Contingency	Scenario 3 MINUS Scenario 1 Peaker	Intermediate	Baseload	Wind
No EPU	-	-	-	(4)
$34 CO2	-	-	-	(4)
$9 CO2	(2)	1	-	-
CO2 Delayed	-	-	-	(4)
CO2 Reduction	-	-	-	(2)
High Capital Cost +10%	(2)	1	-	-
Low Capital Cost -10%	-	-	-	(4)
Low Externalities	-	-	-	(4)
Coal - 20%	(2)	1	-	-
Coal - 10%	(2)	1	-	-
Coal + 10%	(3)	2	-	(6)
Coal + 20%	-	-	-	(4)
Natural Gas - $1.50	(2)	1	-	-
Natural Gas - $1.00	(2)	1	-	-
Natural Gas - $0.50	(2)	1	-	-
Natural Gas + $0.50	-	-	-	(4)
Natural Gas + $1.00	-	-	-	(4)
Natural Gas + $1.50	-	-	-	(4)
Natural Gas + $2.00	(2)	1	-	2
Natural Gas + $2.50	(2)	1	-	-
Natural Gas No Growth	(2)	1	-	-
Wholesale Market On	-	-	-	-
$35 Wind	(2)	1	-	-
$40 Wind	(2)	1	-	-
$45 Wind	(2)	1	-	-
$50 Wind	(2)	1	-	(2)
$55 Wind	(2)	1	-	-
$60 Wind	-	-	-	(4)
$70 Wind	(2)	1	-	-
$75 Wind	(2)	1	-	-
$80 Wind	(2)	1	-	-
Wind High Credit (20%)	-	-	-	(4)
Wind Low Credit (10%)	(2)	1	-	-
Forecast, Mid-High	3	(2)	-	-
Forecast, High	3	(2)	-	-

Units added (2012-'26)	No EPU 100 MW DSM							
	Scenario 4				Change from Scenario 18 Base			
Contingency	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	5	3	-	4				
$34 CO2	5	3	-	6	-	-	-	2
$9 CO2	7	2	-	-	2	(1)	-	(4)
CO2 Delayed	5	3	-	4	-	-	-	-
CO2 Reduction	3	4	-	10	(2)	1	-	6
High Capital Cost +10%	7	2	-	-	2	(1)	-	(4)
Low Capital Cost -10%	5	3	-	4	-	-	-	-
Low Externalities	5	3	-	4	-	-	-	-
Coal - 20%	5	3	-	4	-	-	-	-
Coal - 10%	5	3	-	4	-	-	-	-
Coal + 10%	5	3	-	4	-	-	-	-
Coal + 20%	5	3	-	4	-	-	-	-
Natural Gas - $1.50	7	2	-	-	2	(1)	-	(4)
Natural Gas - $1.00	5	3	-	4	-	-	-	-
Natural Gas - $0.50	5	3	-	4	-	-	-	-
Natural Gas + $0.50	5	3	-	4	-	-	-	-
Natural Gas + $1.00	5	3	-	4	-	-	-	-
Natural Gas + $1.50	5	3	-	4	-	-	-	-
Natural Gas + $2.00	3	4	-	10	(2)	1	-	6
Natural Gas + $2.50	3	4	-	10	(2)	1	-	6
Natural Gas No Growth	4	3	-	-	(1)	-	-	(4)
Wholesale Market On	5	3	-	-	-	-	-	(4)
$35 Wind	3	4	-	10	(2)	1	-	6
$40 Wind	3	4	-	10	(2)	1	-	6
$45 Wind	3	4	-	10	(2)	1	-	6
$50 Wind	3	4	-	10	(2)	1	-	6
$55 Wind	3	4	-	10	(2)	1	-	6
$60 Wind	5	3	-	4	-	-	-	-
$70 Wind	4	4	-	-	(1)	1	-	(4)
$75 Wind	4	4	-	-	(1)	1	-	(4)
$80 Wind	4	4	-	-	(1)	1	-	(4)
Wind High Credit (20%)	5	3	-	4	-	-	-	-
Wind Low Credit (10%)	5	3	-	6	-	-	-	2
Forecast, Mid-High	6	3	-	2	1	-	-	(2)
Forecast, High	7	3	-	2	2	-	-	(2)

Contingency	Scenario 4 MINUS Scenario 1			
	Peaker	Intermediate	Baseload	Wind
No EPU	1	(1)	-	-
$34 CO2	(2)	1	-	-
$9 CO2	1	(1)	-	-
CO2 Delayed	1	(1)	-	-
CO2 Reduction	1	(1)	-	-
High Capital Cost +10%	1	(1)	-	-
Low Capital Cost -10%	(2)	1	-	(2)
Low Externalities	1	(1)	-	-
Coal - 20%	(1)	-	-	4
Coal - 10%	(1)	-	-	4
Coal + 10%	(2)	1	-	(2)
Coal + 20%	(2)	1	-	(2)
Natural Gas - $1.50	1	(1)	-	-
Natural Gas - $1.00	(1)	-	-	4
Natural Gas - $0.50	(1)	-	-	4
Natural Gas + $0.50	(2)	1	-	(2)
Natural Gas + $1.00	(2)	1	-	(2)
Natural Gas + $1.50	(2)	1	-	(2)
Natural Gas + $2.00	(4)	2	-	4
Natural Gas + $2.50	(4)	2	-	2
Natural Gas No Growth	(2)	1	-	-
Wholesale Market On	(2)	1	-	-
$35 Wind	(4)	2	-	-
$40 Wind	(4)	2	-	-
$45 Wind	(4)	2	-	-
$50 Wind	(4)	2	-	-
$55 Wind	(4)	2	-	2
$60 Wind	(2)	1	-	(2)
$70 Wind	(2)	1	-	-
$75 Wind	(2)	1	-	-
$80 Wind	(2)	1	-	-
Wind High Credit (20%)	1	(1)	-	-
Wind Low Credit (10%)	(1)	-	-	6
Forecast, Mid-High	1	(1)	-	-
Forecast, High	1	(1)	-	2

NOTE: The following 2 pages provide the total CO_2 emissions during the planning period for each scenario and each contingency along with comparisons to the base case total emissions.

Emissions CO2 (tons, 2012-'26)	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
No EPU	361,537,750	367,024,796	362,088,012	362,170,966
$34 CO2	349,142,770	367,024,796	350,499,344	348,990,770
$9 CO2	366,923,576	367,024,796	363,262,838	367,682,622
CO2 Delayed	362,518,342	367,024,796	363,067,936	363,123,330
CO2 Reduction	327,587,438	327,587,438	330,421,844	327,775,756
High Capital Cost +10%	365,736,694	367,628,944	362,088,012	366,491,734
Low Capital Cost -10%	357,609,584	367,024,796	358,166,660	361,307,086
Low Externalities	361,537,750	367,024,796	362,088,012	362,170,966
Coal - 20%	367,033,190	367,371,258	363,380,270	363,437,992
Coal - 10%	366,596,750	367,200,176	362,944,152	363,007,106
Coal + 10%	357,960,002	366,916,544	360,639,376	360,763,904
Coal + 20%	355,526,758	366,584,016	355,223,890	358,317,030
Natural Gas - $1.50	348,453,570	363,240,988	344,798,020	349,834,590
Natural Gas - $1.00	358,382,162	365,737,626	354,741,356	355,076,700
Natural Gas - $0.50	363,724,980	366,852,336	360,079,688	360,235,430
Natural Gas + $0.50	360,145,904	367,080,512	359,841,752	362,980,980
Natural Gas + $1.00	360,444,146	367,155,608	360,139,930	361,514,166
Natural Gas + $1.50	359,656,224	367,221,960	360,220,276	360,724,626
Natural Gas + $2.00	358,852,406	367,290,840	353,439,620	352,579,818
Natural Gas + $2.50	354,201,538	367,338,968	353,502,672	352,364,322
Natural Gas No Growth	332,190,232	365,799,544	327,564,962	331,845,920
Wholesale Market On	325,170,414	347,106,050	322,828,676	325,274,088
$35 Wind	351,723,416	352,921,888	347,581,510	351,095,814
$40 Wind	351,723,416	352,921,888	348,036,614	351,382,526
$45 Wind	351,723,416	360,608,940	348,036,614	351,382,526
$55 Wind ($50 in Minn Wind)	351,723,416	360,608,940	349,237,618	351,382,526
$60 Wind ($55 in Minn Wind)	356,390,538	367,024,796	352,663,904	351,382,526
$60 Wind	359,346,450	367,024,796	359,043,306	361,307,086
$70 Wind	365,736,694	367,024,796	362,088,012	365,703,634
$75 Wind	365,736,694	367,024,796	362,088,012	365,703,634
$80 Wind	365,736,694	367,024,796	362,088,012	365,703,634
Wind High Credit (20%)	361,537,750	367,024,796	362,088,012	362,170,966
Wind Low Credit (10%)	365,736,694	367,024,796	362,088,012	360,085,696
Forecast, Mid-High	364,447,166	367,061,634	358,972,966	363,649,864
Forecast, High	365,925,034	367,171,196	362,737,428	361,884,830
MAX	367,033,190	367,628,944	363,380,270	367,682,622
AVERAGE	357,097,702	364,020,847	355,079,352	356,585,862
MIN	325,170,414	327,587,438	322,828,676	325,274,088

Emissions CO2 (tons 2012-'26) Difference from base case, same contingency.	No EPU	No EPU No CO2	No EPU Wind Mandate	No EPU 100 MW DSM
No EPU	-	5,487,046	550,262	633,216
$34 CO2	-	17,882,026	1,356,574	(152,000)
$9 CO2	-	101,220	(3,660,738)	759,046
CO2 Delayed	-	4,506,454	549,594	604,988
CO2 Reduction	-	-	2,834,406	188,318
High Capital Cost +10%	-	1,892,250	(3,648,682)	755,040
Low Capital Cost -10%	-	9,415,212	557,076	3,697,502
Low Externalities	-	5,487,046	550,262	633,216
Coal - 20%	-	338,068	(3,652,920)	(3,595,198)
Coal - 10%	-	603,426	(3,652,598)	(3,589,644)
Coal + 10%	-	8,956,542	2,679,374	2,803,902
Coal + 20%	-	11,057,258	(302,868)	2,790,272
Natural Gas - $1.50	-	14,787,418	(3,655,550)	1,381,020
Natural Gas - $1.00	-	7,355,464	(3,640,806)	(3,305,462)
Natural Gas - $0.50	-	3,127,356	(3,645,292)	(3,489,550)
Natural Gas + $0.50	-	6,934,608	(304,152)	2,835,076
Natural Gas + $1.00	-	6,711,462	(304,216)	1,070,020
Natural Gas + $1.50	-	7,565,736	564,052	1,068,402
Natural Gas + $2.00	-	8,438,434	(5,412,786)	(6,272,588)
Natural Gas + $2.50	-	13,137,430	(698,866)	(1,837,216)
Natural Gas No Growth	-	33,609,312	(4,625,270)	(344,312)
Wholesale Market On	-	21,935,636	(2,341,738)	103,674
$35 Wind	-	1,198,472	(4,141,906)	(627,602)
$40 Wind	-	1,198,472	(3,686,802)	(340,890)
$45 Wind	-	8,885,524	(3,686,802)	(340,890)
$55 Wind ($50 in Minn Wind)	-	8,885,524	(2,485,798)	(340,890)
$60 Wind ($55 in Minn Wind)	-	10,634,258	(3,726,634)	(5,008,012)
$60 Wind	-	7,678,346	(303,144)	1,960,636
$70 Wind	-	1,288,102	(3,648,682)	(33,060)
$75 Wind	-	1,288,102	(3,648,682)	(33,060)
$80 Wind	-	1,288,102	(3,648,682)	(33,060)
Wind High Credit (20%)	-	5,487,046	550,262	633,216
Wind Low Credit (10%)	-	1,288,102	(3,648,682)	(5,650,998)
Forecast, Mid-High	-	2,614,468	(5,474,200)	(797,302)
Forecast, High	-	1,246,162	(3,187,606)	(4,040,204)
MAX	-	33,609,312	2,834,406	3,697,502
AVERAGE	-	7,473,365	(1,899,420)	(259,971)
MIN	-	-	(5,412,786)	(6,272,588)

NOTE: The following 8 pages provide the total MW added of each unit type during the planning period for each scenario and each contingency along with comparisons to the base case total total MW added.

MW added (2012-'26)	No EPU							
	Scenario 1				Change from Scenario 1 Base			
Contingency	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	756	1,212	-	400				
$34 CO2	1,323	606	-	600	567	(606)	-	200
$9 CO2	1,134	909	-	-	378	(303)	-	(400)
CO2 Delayed	756	1,212	-	400	-	-	-	-
CO2 Reduction	378	1,515	-	1,000	(378)	303	-	600
High Capital Cost +10%	1,134	909	-	-	378	(303)	-	(400)
Low Capital Cost -10%	1,323	606	-	600	567	(606)	-	200
Low Externalities	756	1,212	-	400	-	-	-	-
Coal - 20%	1,134	909	-	-	378	(303)	-	(400)
Coal - 10%	1,134	909	-	-	378	(303)	-	(400)
Coal + 10%	1,323	606	-	600	567	(606)	-	200
Coal + 20%	1,323	606	-	600	567	(606)	-	200
Natural Gas - $1.50	1,134	909	-	-	378	(303)	-	(400)
Natural Gas - $1.00	1,134	909	-	-	378	(303)	-	(400)
Natural Gas - $0.50	1,134	909	-	-	378	(303)	-	(400)
Natural Gas + $0.50	1,323	606	-	600	567	(606)	-	200
Natural Gas + $1.00	1,323	606	-	600	567	(606)	-	200
Natural Gas + $1.50	1,323	606	-	600	567	(606)	-	200
Natural Gas + $2.00	1,323	606	-	600	567	(606)	-	200
Natural Gas + $2.50	1,323	606	-	800	567	(606)	-	400
Natural Gas No Growth	1,134	1,008	-	-	378	(204)	-	(400)
Wholesale Market On	1,323	606	-	-	567	(606)	-	(400)
$35 Wind	1,323	606	-	1,000	567	(606)	-	600
$40 Wind	1,323	606	-	1,000	567	(606)	-	600
$45 Wind	1,323	606	-	1,000	567	(606)	-	600
$50 Wind	1,323	606	-	1,000	567	(606)	-	600
$55 Wind	1,323	606	-	800	567	(606)	-	400
$60 Wind	1,323	606	-	600	567	(606)	-	200
$70 Wind	1,134	909	-	-	378	(303)	-	(400)
$75 Wind	1,134	909	-	-	378	(303)	-	(400)
$80 Wind	1,134	909	-	-	378	(303)	-	(400)
Wind High Credit (20%)	756	1,212	-	400	-	-	-	-
Wind Low Credit (10%)	1,134	909	-	-	378	(303)	-	(400)
Forecast, Mid-High	945	1,212	-	200	189	-	-	(200)
Forecast, High	1,134	1,212	-	-	378	-	-	(400)
MAX	1,323	1,515	-	1,000	567	303	-	600
AVERAGE	1,150	843	-	394	406	(380)	-	(6)
MIN	378	606	-	-	(378)	(606)	-	(400)

MW Diff. (2012-'26) Contingency
No EPU
$34 CO2
$9 CO2
CO2 Delayed
CO2 Reduction
High Capital Cost +10%
Low Capital Cost -10%
Low Externalities
Coal - 20%
Coal - 10%
Coal + 10%
Coal + 20%
Natural Gas - $1.50
Natural Gas - $1.00
Natural Gas - $0.50
Natural Gas + $0.50
Natural Gas + $1.00
Natural Gas + $1.50
Natural Gas + $2.00
Natural Gas + $2.50
Natural Gas No Growth
Wholesale Market On
$35 Wind
$40 Wind
$45 Wind
$50 Wind
$55 Wind
$60 Wind
$70 Wind
$75 Wind
$80 Wind
Wind High Credit (20%)
Wind Low Credit (10%)
Forecast, Mid-High
Forecast, High

MW added (2012-'26) Contingency	No EPU No CO2 Scenario 2 Peaker	Intermediate	Baseload	Wind	Change from Scen 2 Base Peaker	Intermediate	Baseload	Wind
No EPU	1,134	909	-	-				
$34 CO2	1,134	909	-	-	-	-	-	-
$9 CO2	1,134	909	-	-	-	-	-	-
CO2 Delayed	1,134	909	-	-	-	-	-	-
CO2 Reduction	378	1,515	-	1,000	(756)	606	-	####
High Capital Cost +10%	1,134	909	-	-	-	-	-	-
Low Capital Cost -10%	1,134	909	-	-	-	-	-	-
Low Externalities	1,134	909	-	-	-	-	-	-
Coal - 20%	1,134	909	-	-	-	-	-	-
Coal - 10%	1,134	909	-	-	-	-	-	-
Coal + 10%	1,134	909	-	-	-	-	-	-
Coal + 20%	1,134	909	-	-	-	-	-	-
Natural Gas - $1.50	1,134	909	-	-	-	-	-	-
Natural Gas - $1.00	1,134	909	-	-	-	-	-	-
Natural Gas - $0.50	1,134	909	-	-	-	-	-	-
Natural Gas + $0.50	1,134	909	-	-	-	-	-	-
Natural Gas + $1.00	1,134	909	-	-	-	-	-	-
Natural Gas + $1.50	1,134	909	-	-	-	-	-	-
Natural Gas + $2.00	1,134	909	-	-	-	-	-	-
Natural Gas + $2.50	1,134	909	-	-	-	-	-	-
Natural Gas No Growth	1,134	909	-	-	-	-	-	-
Wholesale Market On	1,323	606	-	-	189	(303)	-	-
$35 Wind	1,323	606	-	1,000	189	(303)	-	####
$40 Wind	1,323	606	-	1,000	189	(303)	-	####
$45 Wind	1,323	606	-	600	189	(303)	-	600
$50 Wind	1,323	606	-	600	189	(303)	-	600
$55 Wind	1,134	909	-	-	-	-	-	-
$60 Wind	1,134	909	-	-	-	-	-	-
$70 Wind	1,134	909	-	-	-	-	-	-
$75 Wind	1,134	909	-	-	-	-	-	-
$80 Wind	1,134	909	-	-	-	-	-	-
Wind High Credit (20%)	1,134	909	-	-	-	-	-	-
Wind Low Credit (10%)	1,134	909	-	-	-	-	-	-
Forecast, Mid-High								
Forecast, High								
MAX	1,323	1,515	-	1,000	189	606	-	####
AVERAGE	1,140	881	-	127	6	(28)	-	131
MIN	378	606	-	-	(756)	(303)	-	-

MW Diff. (2012-'26)	Scenario 2 MINUS Scenario 1			
Contingency	Peaker	Intermediate	Baseload	Wind
No EPU	378	(303)	-	(400)
$34 CO2	(189)	303	-	(600)
$9 CO2	-	-	-	-
CO2 Delayed	378	(303)	-	(400)
CO2 Reduction	-	-	-	-
High Capital Cost +10%	-	-	-	-
Low Capital Cost -10%	(189)	303	-	(600)
Low Externalities	378	(303)	-	(400)
Coal - 20%	-	-	-	-
Coal - 10%	-	-	-	-
Coal + 10%	(189)	303	-	(600)
Coal + 20%	(189)	303	-	(600)
Natural Gas - $1.50	-	-	-	-
Natural Gas - $1.00	-	-	-	-
Natural Gas - $0.50	-	-	-	-
Natural Gas + $0.50	(189)	303	-	(600)
Natural Gas + $1.00	(189)	303	-	(600)
Natural Gas + $1.50	(189)	303	-	(600)
Natural Gas + $2.00	(189)	303	-	(600)
Natural Gas + $2.50	(189)	303	-	(800)
Natural Gas No Growth	-	(99)	-	-
Wholesale Market On	-	-	-	-
$35 Wind	-	-	-	-
$40 Wind	-	-	-	-
$45 Wind	-	-	-	(400)
$50 Wind	-	-	-	(400)
$55 Wind	(189)	303	-	(800)
$60 Wind	(189)	303	-	(600)
$70 Wind	-	-	-	-
$75 Wind	-	-	-	-
$80 Wind	-	-	-	-
Wind High Credit (20%)	378	(303)	-	(400)
Wind Low Credit (10%)	-	-	-	-
Forecast, Mid-High				
Forecast, High				

MW added (2012-'26) Contingency	No EPU Wind Mandate							
	Scenario 3				Change from Scenario 13 Base			
	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	756	3,268	-	-				
$34 CO2	1,323	1,634	-	200	567	(1,634)	-	200
$9 CO2	756	3,268	-	-	-	-	-	-
CO2 Delayed	756	3,268	-	-	-	-	-	-
CO2 Reduction	378	4,085	-	800	(378)	817	-	800
High Capital Cost +10%	756	3,268	-	-	-	-	-	-
Low Capital Cost -10%	1,323	1,634	-	200	567	(1,634)	-	200
Low Externalities	756	3,268	-	-	-	-	-	-
Coal - 20%	756	3,268	-	-	-	-	-	-
Coal - 10%	756	3,268	-	-	-	-	-	-
Coal + 10%	756	3,268	-	-	-	-	-	-
Coal + 20%	1,323	1,634	-	200	567	(1,634)	-	200
Natural Gas - $1.50	756	3,268	-	-	-	-	-	-
Natural Gas - $1.00	756	3,268	-	-	-	-	-	-
Natural Gas - $0.50	756	3,268	-	-	-	-	-	-
Natural Gas + $0.50	1,323	1,634	-	200	567	(1,634)	-	200
Natural Gas + $1.00	1,323	1,634	-	200	567	(1,634)	-	200
Natural Gas + $1.50	1,323	1,634	-	200	567	(1,634)	-	200
Natural Gas + $2.00	945	2,451	-	800	189	(817)	-	800
Natural Gas + $2.50	945	2,451	-	800	189	(817)	-	800
Natural Gas No Growth	756	3,255	-	-	-	(13)	-	-
Wholesale Market On	1,323	1,634	-	-	567	(1,634)	-	-
$35 Wind	945	2,451	-	1,000	189	(817)	-	1,000
$40 Wind	945	2,451	-	1,000	189	(817)	-	1,000
$45 Wind	945	2,451	-	1,000	189	(817)	-	1,000
$50 Wind	945	2,451	-	800	189	(817)	-	800
$55 Wind	945	2,451	-	800	189	(817)	-	800
$60 Wind	1,323	1,634	-	200	567	(1,634)	-	200
$70 Wind	756	3,268	-	-	-	-	-	-
$75 Wind	756	3,268	-	-	-	-	-	-
$80 Wind	756	3,268	-	-	-	-	-	-
Wind High Credit (20%)	756	3,268	-	-	-	-	-	-
Wind Low Credit (10%)	756	3,268	-	-	-	-	-	-
Forecast, Mid-High	1,512	1,634	-	200	756	(1,634)	-	200
Forecast, High	1,701	1,634	-	-	945	(1,634)	-	-
MAX	1,701	4,085	-	1,000	945	817	-	1,000
AVERAGE	961	2,661	-	246	211	(625)	-	253
MIN	378	1,634	-	-	(378)	(1,634)	-	-

MW Diff. (2012-'26)	Scenario 3 MINUS Scenario 1			
Contingency	Peaker	Intermediate	Baseload	Wind
No EPU	-	2,056	-	(400)
$34 CO2	-	1,028	-	(400)
$9 CO2	(378)	2,359	-	-
CO2 Delayed	-	2,056	-	(400)
CO2 Reduction	-	2,570	-	(200)
High Capital Cost +10%	(378)	2,359	-	-
Low Capital Cost -10%	-	1,028	-	(400)
Low Externalities	-	2,056	-	(400)
Coal - 20%	(378)	2,359	-	-
Coal - 10%	(378)	2,359	-	-
Coal + 10%	(567)	2,662	-	(600)
Coal + 20%	-	1,028	-	(400)
Natural Gas - $1.50	(378)	2,359	-	-
Natural Gas - $1.00	(378)	2,359	-	-
Natural Gas - $0.50	(378)	2,359	-	-
Natural Gas + $0.50	-	1,028	-	(400)
Natural Gas + $1.00	-	1,028	-	(400)
Natural Gas + $1.50	-	1,028	-	(400)
Natural Gas + $2.00	(378)	1,845	-	200
Natural Gas + $2.50	(378)	1,845	-	-
Natural Gas No Growth	(378)	2,247	-	-
Wholesale Market On	-	1,028	-	-
$35 Wind	(378)	1,845	-	-
$40 Wind	(378)	1,845	-	-
$45 Wind	(378)	1,845	-	-
$50 Wind	(378)	1,845	-	(200)
$55 Wind	(378)	1,845	-	-
$60 Wind	-	1,028	-	(400)
$70 Wind	(378)	2,359	-	-
$75 Wind	(378)	2,359	-	-
$80 Wind	(378)	2,359	-	-
Wind High Credit (20%)	-	2,056	-	(400)
Wind Low Credit (10%)	(378)	2,359	-	-
Forecast, Mid-High	567	422	-	-
Forecast, High	567	422	-	-

MW added (2012-'26)	No EPU 100 MW DSM							
	Scenario 4				Change from Scenario 4 Base			
Contingency	Peaker	Intermediate	Baseload	Wind	Peaker	Intermediate	Baseload	Wind
No EPU	945	2,451	-	400				
$34 CO2	945	2,451	-	600	-	-	-	200
$9 CO2	1,323	1,634	-	-	378	(817)	-	(400)
CO2 Delayed	945	2,451	-	400	-	-	-	-
CO2 Reduction	567	3,268	-	1,000	(378)	817	-	600
High Capital Cost +10%	1,323	1,634	-	-	378	(817)	-	(400)
Low Capital Cost -10%	945	2,451	-	400	-	-	-	-
Low Externalities	945	2,451	-	400	-	-	-	-
Coal - 20%	945	2,451	-	400	-	-	-	-
Coal - 10%	945	2,451	-	400	-	-	-	-
Coal + 10%	945	2,451	-	400	-	-	-	-
Coal + 20%	945	2,451	-	400	-	-	-	-
Natural Gas - $1.50	1,323	1,634	-	-	378	(817)	-	(400)
Natural Gas - $1.00	945	2,451	-	400	-	-	-	-
Natural Gas - $0.50	945	2,451	-	400	-	-	-	-
Natural Gas + $0.50	945	2,451	-	400	-	-	-	-
Natural Gas + $1.00	945	2,451	-	400	-	-	-	-
Natural Gas + $1.50	945	2,451	-	400	-	-	-	-
Natural Gas + $2.00	567	3,268	-	1,000	(378)	817	-	600
Natural Gas + $2.50	567	3,268	-	1,000	(378)	817	-	600
Natural Gas No Growth	756	3,255	-	-	(189)	804	-	(400)
Wholesale Market On	945	2,451	-	-	-	-	-	(400)
$35 Wind	567	3,268	-	1,000	(378)	817	-	600
$40 Wind	567	3,268	-	1,000	(378)	817	-	600
$45 Wind	567	3,268	-	1,000	(378)	817	-	600
$50 Wind	567	3,268	-	1,000	(378)	817	-	600
$55 Wind	567	3,268	-	1,000	(378)	817	-	600
$60 Wind	945	2,451	-	400	-	-	-	-
$70 Wind	756	3,268	-	-	(189)	817	-	(400)
$75 Wind	756	3,268	-	-	(189)	817	-	(400)
$80 Wind	756	3,268	-	-	(189)	817	-	(400)
Wind High Credit (20%)	945	2,451	-	400	-	-	-	-
Wind Low Credit (10%)	945	2,451	-	600	-	-	-	200
Forecast, Mid-High	1,134	2,451	-	200	189	-	-	(200)
Forecast, High	1,323	2,451	-	200	378	-	-	(200)
MAX	1,323	3,268	-	1,000	378	817	-	600
AVERAGE	886	2,661	-	446	(61)	216	-	47
MIN	567	1,634	-	-	(378)	(817)	-	(400)

MW Diff. (2012-'26) Contingency	Scenario 4 MINUS Scenario 1 Peaker	Intermediate	Baseload	Wind
No EPU	189	1,239	-	-
$34 CO2	(378)	1,845	-	-
$9 CO2	189	725	-	-
CO2 Delayed	189	1,239	-	-
CO2 Reduction	189	1,753	-	-
High Capital Cost +10%	189	725	-	-
Low Capital Cost -10%	(378)	1,845	-	(200)
Low Externalities	189	1,239	-	-
Coal - 20%	(189)	1,542	-	400
Coal - 10%	(189)	1,542	-	400
Coal + 10%	(378)	1,845	-	(200)
Coal + 20%	(378)	1,845	-	(200)
Natural Gas - $1.50	189	725	-	-
Natural Gas - $1.00	(189)	1,542	-	400
Natural Gas - $0.50	(189)	1,542	-	400
Natural Gas + $0.50	(378)	1,845	-	(200)
Natural Gas + $1.00	(378)	1,845	-	(200)
Natural Gas + $1.50	(378)	1,845	-	(200)
Natural Gas + $2.00	(756)	2,662	-	400
Natural Gas + $2.50	(756)	2,662	-	200
Natural Gas No Growth	(378)	2,247	-	-
Wholesale Market On	(378)	1,845	-	-
$35 Wind	(756)	2,662	-	-
$40 Wind	(756)	2,662	-	-
$45 Wind	(756)	2,662	-	-
$50 Wind	(756)	2,662	-	-
$55 Wind	(756)	2,662	-	200
$60 Wind	(378)	1,845	-	(200)
$70 Wind	(378)	2,359	-	-
$75 Wind	(378)	2,359	-	-
$80 Wind	(378)	2,359	-	-
Wind High Credit (20%)	189	1,239	-	-
Wind Low Credit (10%)	(189)	1,542	-	600
Forecast, Mid-High	189	1,239	-	-
Forecast, High	189	1,239	-	200

CERTIFICATE OF SERVICE

I, Jan Mottaz, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Comments of the Division of Energy Resources of the Minnesota Department of Commerce

Docket No E002/RP-10-825

Dated this **18th day of December 2012**

/s/Jan Mottaz

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No	OFF_SL_10-825_RP-10-825
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_10-825_RP-10-825
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Paper Service	No	OFF_SL_10-825_RP-10-825
B. Andrew	Brown	brown.andrew@dorsey.com	Dorsey & Whitney LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_10-825_RP-10-825
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_10-825_RP-10-825
Edward	Garvey	garveyed@aol.com		32 Lawton Street St. Paul, MN 55102	Paper Service	No	OFF_SL_10-825_RP-10-825
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	Yes	OFF_SL_10-825_RP-10-825

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Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_10-825_RP-10-825
Hank	Koegel	N/A	enXco	10 Second St., NE, Ste 107 Minneapolis, MN 55413	Paper Service	No	OFF_SL_10-825_RP-10-825
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_10-825_RP-10-825
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Mark	Lindquist	N/A	The Minnesota Project	57107 422nd St New Ulm, MN 56073-4321	Paper Service	No	OFF_SL_10-825_RP-10-825
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_10-825_RP-10-825
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Paper Service	No	OFF_SL_10-825_RP-10-825

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Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_10-825_RP-10-825
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_10-825_RP-10-825
Thomas L.	Osteraas	tomosteraas@excelsiorenergy.com	Excelsior Energy	225 S 6th St Ste 1730 Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825
Joshua	Pearson	N/A	enXco, Inc.	15445 Innovation Drive San Diego, CA 92128	Paper Service	No	OFF_SL_10-825_RP-10-825
Kent	Ragsdale	kentragsdale@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_10-825_RP-10-825
Kevin	Reuther		MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	Yes	OFF_SL_10-825_RP-10-825
Matthew J.	Schuerger P.E.		Energy Systems Consulting Services, LLC	P.O. Box 16129 St. Paul, MN 55116	Paper Service	No	OFF_SL_10-825_RP-10-825
Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC	15347 Boulder Pointe Road Eden Prairie, MN 55347	Paper Service	No	OFF_SL_10-825_RP-10-825

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