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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF ITS 2023 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

MPUC Docket No. E002/AA-22-179
CAH Docket No. 21-2500-40336

SURREBUTTAL TESTIMONY OF DR. STEVE RAKOW

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE

SEPTEMBER 17, 2025

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I. INTRODUCTION

Q. Would you state your name, occupation and business address?

A. My name is Dr. Steve Rakow. I am employed as a Public Utilities Analyst Coordinator by the Minnesota Department of Commerce (Department). My business address is 85 7th Place East, Suite 280, St. Paul, Minnesota 55101-2198.

Q. What is your educational and professional background?

A. A summary of these items is included as Ex. DOC - ___, at SR-S-1 (Rakow Surrebuttal).

Q. What is your experience on regulatory matters?

A. I have provided economic analysis in numerous resource planning and resource acquisition filings for 29 years. A summary of these items is included as Ex. DOC - ___, at SR-S-1 (Rakow Surrebuttal). I have run the Department's resource planning model for over 15 years; initially the Department used the Strategist model, however, the Department now uses the EnCompass model. Relevant to this case is the fact that a resource planning model contains a production cost modeling routine.

I also follow issues related to resource planning and resource acquisition at the Midcontinent Independent System Operator, Inc. (MISO). Finally, I provide analysis of a variety of other filings before the Minnesota Public Utilities Commission (Commission).

II. PURPOSE AND SCOPE

Q. Have you previously filed testimony in this proceeding?

A. No.

Q. What are your responsibilities in this proceeding?

A. I am responding to two topics raised in Xcel witness Nicholas J. Detmer's rebuttal testimony:

(1) use of the PLEXOS model to estimate incremental power costs attributable to the extended outage of the Prairie Island Nuclear Generating Plan (PINGP); and

(2) critique of an alternative model preferred by Xcel Large Industrials (XLI) Witness Mr. Brian C. Andrews, an LMP-based spreadsheet calculation.

III. XCEL'S METHOD FOR ESTIMATING INCREMENTAL COSTS

Q. What method did Xcel propose be used to estimate incremental power costs?

A. In direct testimony, Mr. Detmer modeled the cost of replacement power needed for the PINGP outage using PLEXOS, a production cost model.[1] According to Mr. Detmer, Xcel estimated the outage costs by creating two scenarios. First, the Company created a base case in PLEXOS representing actual operations without PINGP on-line. The Company then calibrated the base case, meaning "the model closely resembled actual operations."[2] Xcel then saved the outputs from this step. Second, Xcel modified the

[1] Ex. Xcel-___ at 10-11 (Detmer Direct).
[2] Ex. Xcel-___ at 16 (Detmer Direct).

base case into a change case; the change being to make PINGP available.[3] Xcel then saved the outputs from this step as well. Xcel then calculated the difference in total system costs reported by PLEXOS in the two steps. The difference between the total cost of the base case and the change case is the estimated cost of the PINGP outage.

Using this production cost modeling approach, Xcel "estimated the total incremental power cost for the NSP System during the PINGP outage (for both Units 1 and 2) to be approximately $48.5 million ($34.3 million for the Minnesota jurisdiction)."[4]

Q. What criticisms did others have regarding Xcel's proposed method?

A. In direct testimony, XLI witness Mr. Brian C. Andrews critiques Xcel's analysis. First, Mr. Andrews states:

> the outage at PINGP should not have had any major effect on the Locational Marginal Prices ("LMP") within the Midcontinent Independent System Operator ("MISO"). Therefore, generation output of Xcel's other resources should've been largely unchanged.[5]

In essence, Mr. Andrews states that he would expect PINGP's loss would only cause small changes in the energy output of Xcel's units in MISO's actual dispatch. This is because most of the change in energy output to account for loss of PINGP would be spread across generating units throughout MISO (i.e., more broadly than just generating units controlled by Xcel). This expected "allocation" of the replacement energy

[3] Ex. Xcel-___ at 16 (Detmer Direct).
[4] Ex. Xcel-___ at 16 (Detmer Direct).
[5] Ex. XLI-___ at 2-3 (Andrews Direct).

throughout MISO is attributable to the assumption that there would be only small changes in LMPs.

Q. Can you explain what an LMP is and how it functions?

A. Sure. Xcel witness Mr. Detmer discusses how LMPs are determined.[6] Briefly, there are three components to an LMP: the cost of energy, the cost of congestion, and the cost of losses. Mr. Detmer also explains how the MISO market operates and how the MISO market impacts customer bills via the LMPs.[7]

Q. Did Mr. Detmer address the issue of how much LMPs would change?

A. Yes. In rebuttal testimony, Mr. Detmer agreed that the loss of PINGP would not have a major impact on LMPs and that assuming the change to be zero is the most reasonable approach:

> the inclusion of PINGP would likely change the LMPs to be slightly lower than the real-life LMPs (since including PINGP would likely have offset the highest cost, or marginal generator in the base case). The extent to which LMPs would have changed, however, is difficult, if not impossible, to estimate and the result of any analysis would be a rough estimate. So, rather than speculate as to the magnitude of the change, the Company assumed the change in LMPs to be zero. This is not a perfect assumption but, as I explain below, it is the most reasonable approach.[8]

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[6] Ex. Xcel-___ at 10-11 (Detmer Direct).
[7] Ex. Xcel-___ at 3-10 (Detmer Direct).
[8] Ex. Xcel-___ at 5 (Detmer Rebuttal).

Elsewhere in the rebuttal testimony, however, Mr. Detmer claims that "the availability of PINGP would impact the output of other NSP generators."[9] The reason Mr. Detmer gives for this impact is that:

> the entire MISO footprint is not the appropriate comparison when considering the significance of a unit located in Minnesota. Instead, the MISO segment identified as MISO North is a better reference in this case because constraints in the MISO transmission system frequently impede the flow of energy into and out of MISO North.[10]

Put simply, Mr. Detmer implausibly asserts both that no LMP change is the most reasonable assumption as a result of PINGP's loss, and also that PINGP's loss would significantly impact other Xcel generating units.

Q. What is your response to Mr. Detmer?

A. Mr. Detmer's assertions are internally inconsistent. It is unlikely to be the case that the loss of PINGP would simultaneously have minimal impact on LMPs and significantly impact the output of other NSP generators due to constraints, because all generators are dispatched based upon LMPs. If LMPs do not change meaningfully, then the output of the generators would not be expected to change to a meaningful degree either.

On the other hand, if loss of PINGP is accompanied by constraints that force other NSP generators to increase output, then those NSP generators would only ramp up their output if LMPs at their locations increased to a level equal to or greater than

[9] Ex. Xcel-___ at 10 (Detmer Rebuttal).
[10] Ex. Xcel-___ at 10 (Detmer Rebuttal).

those generators' variable cost. That is, the constraints would change LMPs enough to trigger the incremental generation.

Q. If these scenarios are likely mutually exclusive, which one do you find more persuasive?

A. For the reasons discussed below, I conclude that the no LMP change scenario is more probable. As a result, I do not find Xcel's assumption that loss of PINGP's energy would be replaced by Xcel's own generation (as opposed to the MISO market) persuasive.

Q. Do the results of Mr. Detmer's modeling show the impact of the change case is mostly within the MISO market or mostly within Xcel's generators?

A. The file "7.30.24 reply comments Workpaper 2_2023 PI Plexos Results REVISED TRADE SECRET IN ENTIRETY.xlsx"[11] contains PLEXOS outputs for September 19, 2023 to December 31, 2023 for both the base case and change case. For each unit I subtracted total generation in the base case from total generation in the change case. The total change was summed for all units in the same category. The results are presented below in Table 5.

[11] Ex. Xcel ___ (NJD-2), Schedule 1 (Detmer Rebuttal).

Table 5: 2023 Change in Output by Category[12]

Category	MWh	% of Nuclear
	[redacted]	[redacted]
Xcel CC	[redacted]	[redacted]
Xcel Coal	[redacted]	[redacted]
Xcel Peaker	[redacted]	[redacted]
Xcel RDF	[redacted]	[redacted]
Xcel Nuclear	[redacted]	[redacted]
MISO Purchase	[redacted]	[redacted]
MISO Sales	[redacted]	[redacted]
Extra Sales	[redacted]	[redacted]
Total	[redacted]	[redacted]

END TRADE SECRET

Table 5 confirms that Xcel's modeling assumes that "constraints in the MISO transmission system frequently impede the flow of energy into and out of MISO North."[13] Thus, the majority of the change happens within Xcel's units and not MISO purchases/sales.

Q. Is it possible to evaluate whether MISO transmission system constraints impede the flow of energy in and out of MISO North as frequently as claimed by Mr. Detmer and Xcel's PLEXOS modeling?

A. Yes. To the extent that there are constraints, those constraints would force LMPs to be different at locations on opposite sides of the constraint. Mr. Detmer's claim is that LMPs in MISO North region are consistently higher than elsewhere in MISO, a difference

[12] Increased sales are shown as a negative number in the table since increased sales are a 'sink' for increased nuclear generation in the same way that decreased generation from Xcel's coal units is also a sink.
[13] Ex. Xcel-___ at 10 (Detmer Rebuttal).

which reflects an inability to import least-cost energy and thus triggers higher cost units within MISO North to produce energy to make up for the inability to increase imports.

The validity of Mr. Detmer's statement regarding the impacts of congestion that create higher LMPs in MISO North can be checked by comparing the LMPs at the Minnesota hub, representing MISO North to the LMPs at various other hubs spread across MISO. Table 1 shows the number of hours each of seven hubs is the highest cost hub in MISO.

Table 1: Number of Hours at Highest Cost
(4th Quarter 2023)[14, 15]

Node	October	November	December
ARKANSAS.HUB	5	-	4
ILLINOIS.HUB	64	39	9
INDIANA.HUB	166	229	163
LOUISIANA.HUB	24	9	61
MICHIGAN.HUB	62	180	133
MINN.HUB	294	186	247
TEXAS.HUB	132	81	131
TOTAL	747	724	748

Table 1 shows that the Minnesota hub was the highest cost hub 294 hours (39.5% of hours) in October 2023, 186 hours (25.8%) in November 2023, and 247 hours (33.2%) in December 2023. Overall, the Minnesota hub was the highest cost hub 727 hours (32.9%) in the fourth quarter of 2023.

In summary, Table 1 shows that the Minnesota hub had the highest LMP at times. But, the Minnesota hub had the highest LMP less than half the hours in any one month.

[14] Data is based upon real-time LMPs reported by MISO.
[15] Note that during a handful of hours each month multiple hubs have the same highest cost; when this happens both hubs are counted as having the highest cost in that hour. This explains the fact that the total adds up to more than the number of hours in a month.

Table 2 shows the number of hours each of 7 hubs is the highest cost hub by 30 percent or more. This is shown to check how often the hubs are not just the highest cost, but the highest cost by a significant margin.

Table 2: Number of Hours at Highest Cost by 30%+
(4th Quarter 2023)

Node	October	November	December
ARKANSAS.HUB	-	-	2
ILLINOIS.HUB	3	7	-
INDIANA.HUB	7	15	5
LOUISIANA.HUB	-	-	-
MICHIGAN.HUB	1	-	1
MINN.HUB	51	35	29
TEXAS.HUB	2	-	-
TOTAL	64	57	37

Table 2 shows that, while the Minnesota hub had the highest cost about one-third of the time, it was very rare for the congestion to cause LMPs at the Minnesota hub to be significantly greater that the other hubs, using 30 percent as a guideline for "significant."

In summary, while the Minnesota hub (MISO North) does experience congestion—triggering higher LMPs than other hubs—the Minnesota hub experiences more congestion than the other hubs only one-third of the time and it is very rare for that congestion to cause LMPs to diverge by a significant amount. The MISO LMP data does not support a contention of persistent, significant congestion.

Q. Do you have the same data for the first quarter of 2024?

A. Yes. Tables 3 and 4 contain the data for the first quarter of 2024. The conclusion for 2023 is similar to the conclusion based upon the 2023 data.

Table 3: Number of Hours at Highest Cost
(1st Quarter 2024)[16, 17]

Node	January	February	March
ARKANSAS.HUB	2	9	9
ILLINOIS.HUB	11	34	32
INDIANA.HUB	209	255	232
LOUISIANA.HUB	39	14	30
MICHIGAN.HUB	128	130	210
MINN.HUB	284	202	165
TEXAS.HUB	77	60	67
TOTAL	750	704	745

Table 3 shows that the Minnesota hub was the highest-cost hub 284 hours (38.2% of hours) in January 2024, 202 hours (29.0%) in February 2024, and 165 hours (22.2%) in March 2024. Overall, the Minnesota hub was the highest-cost hub 651 hours (29.8%) in the first quarter of 2024.

Table 4: Number of Hours at Highest Cost by 30%+
(1st Quarter 2024)

Node	October	November	December
ARKANSAS.HUB	-	1	-
ILLINOIS.HUB	-	-	2
INDIANA.HUB	-	2	12
LOUISIANA.HUB	1	-	-
MICHIGAN.HUB	11	1	1
MINN.HUB	102	40	39
TEXAS.HUB	13	-	1
TOTAL	127	44	55

[16] Data is based upon real-time LMPs reported by MISO.
[17] Note that during a handful of hours each month multiple hubs have the same highest cost; when this happens both hubs are counted as having the highest cost in that hour. This explains the fact that the total adds up to more than the number of hours in a month.

Table 4 shows that, while Minnesota hub is highest cost about 30 percent of the time in the first quarter of 2024, it was very rare for the congestion to cause LMPs at Minnesota hub to be significantly greater that the other hubs, where 30 percent is a guideline for "significant."

Q. Would use of MISO's day-ahead LMPs change this analysis?

A. It should not change the analysis significantly. MISO's day-ahead market is, in essence, a forecast of MISO's real-time market. While on an hour-to-hour basis there clearly will be differences between the two markets, over a longer duration the differences between real time and day ahead will converge to zero.

Q. Do you have data showing just Minnesota and the closest hub, Illinois?

A. Yes. Tables 5 to 8 below show the same data as Tables 1 to 4, but for only the Minnesota and Illinois hubs.

Table 5: Number of Hours at Highest Cost
(4th Quarter 2023)[18, 19]

Node	October	November	December
ILLINOIS.HUB	307	285	242
MINN.HUB	438	435	503
TOTAL	745	720	745

[18] Data is based upon real-time LMPs reported by MISO.
[19] Note that during a handful of hours each month multiple hubs have the same highest cost; when this happens both hubs are counted as having the highest cost in that hour. This explains the fact that the total adds up to more than the number of hours in a month.

Table 6: Number of Hours at Highest Cost by 30+%
(4th Quarter 2023)

Node	October	November	December
ILLINOIS.HUB	-	-	-
MINN.HUB	-	-	-
TOTAL	-	-	-

Table 7: Number of Hours at Highest Cost
(1st Quarter 2024)[20, 21]

Node	January	February	March
ILLINOIS.HUB	248	337	304
MINN.HUB	496	361	442
TOTAL	744	698	746

Table 8: Number of Hours at Highest Cost by 30+%
(1st Quarter 2024)

Node	October	November	December
ILLINOIS.HUB	-	-	-
MINN.HUB	-	-	-
TOTAL	-	-	-

Tables 5 and 7 show that the Minnesota hub had a higher LMP than the Illinois hub about 60 percent of the time in both the fourth quarter of 2023 and first quarter of 2024. There were no instances, however, where the LMP diverged by more than 30 percent.

Overall, restricting the analysis to Minnesota and Illinois does not impact the analysis to a significant degree.

[20] Data is based upon real-time LMPs reported by MISO.
[21] Note that during a handful of hours each month multiple hubs have the same highest cost; when this happens both hubs are counted as having the highest cost in that hour. This explains the fact that the total adds up to more than the number of hours in a month.

Q. Based on your LMP analysis, what do you conclude?

A. The data in Tables 1 through 8 do not support an assumption that loss of PINGP's energy would be replaced by Xcel's own generation due to congestion limiting MISO North's ability to import energy from the rest of MISO. Xcel's PLEXOS modeling should not be relied upon as the impact of increased generation from PINGP does not reflect conditions shown in the actual LMP data.

Q. Did XLI witness Mr. Andrews have any additional criticisms of Xcel's PLEXOs modeling?

A. Yes. Mr. Andrews states that "Xcel claims that it calibrated the model to match actual conditions, but it has provided no demonstration or analysis comparing the costs that are produced by the base case in PLEXOS to its actual costs incurred during the study period."[22]

Q. How did Mr. Detmer respond to this criticism?

A. Mr. Detmer asserted that the analysis sought by Mr. Andrews was excessively burdensome:

> […] the modeling process used to develop the base case relies on robust inputs that calibrate the model to represent actual conditions as closely as is possible. As a result, comparing the costs that are produced by the base case in PLEXOS to actual costs incurred during the study period represents an excessive requirement.[23]

[22] Ex. XLI-___ at 4 (Andrews Direct).
[23] Ex. Xcel-___ at 8 (Detmer Rebuttal).

Q. What is your response to Mr. Detmer?

A. It is not clear to me how producing a table with two columns for Xcel's generators, one showing model costs and the second showing actual costs, is an excessive requirement. Just because Xcel calibrated the energy output does not mean Xcel calibrated the costs as well. As a result, I concur with Mr. Andrew's concern.

Q. What is your conclusion regarding Xcel's use of PLEXOS?

A. In general, I agree that use of a production cost model such as PLEXOS is the best method to address the question in this docket: estimating the incremental cost of the PINGP outage. In this instance, however, Xcel's model is too flawed to provide a reliable estimate. Xcel's PLEXOS outputs conflict with what is known about the real world. Xcel's model reflects significant congestion, forcing Xcel's units to do most of the reacting to changes, but Xcel's congestion assumptions are not supported by real time LMP data. Xcel's PLEXOS analysis should not be relied upon in this case.

IV. XLI'S METHOD FOR ESTIMATING INCREMENTAL COSTS

Q. What method did Mr. Andrews propose in lieu of Xcel's production cost modeling method?

A. Mr. Andrews recommends a Locational Marginal Pricing (LMP) Calculation Method. Mr. Andrews asserts this method provides "a more accurate representation of the replacement power costs [. . .] with a simpler approach."[24] The LMP Calculation Method

[24] Ex. XLI-___ at 15 (Andrews Direct).

assumes the generation output of Xcel's other resources would have been largely unchanged regardless of PINGP's level of operation. If this assumption is true, then the replacement power costs can be determined by calculating the net revenue that would have been earned had the PINGP been operating as usual. Regarding this approach Mr. Andrews states, "[f]or 2023, Xcel conducted the LMP Calculation Method, which is shown in Mr. Krug's Schedule 2.0."[25]

Q. How did Mr. Detmer respond to Mr. Andrews' proposed LMP Calculation Method?

A. Mr. Detmer starts by explaining that the LMP Calculation Method is a simple method used by Xcel "to provide intervenors a more general reference to the impact outages may be contributing to the fuel clause."[26]

Mr. Detmer's first criticism of the LMP Calculation Method is that this method presumes:

> that no other generation would be altered in relation to the availability of PINGP. XLI witness Andrews' basis for this assumption is his claim that MISO is so large in aggregate that even 1,000 MWs of generation from PINGP would not alter the output of other generation facilities.[27]

Regarding when the LMP Calculation Method is appropriate, Mr. Detmer explains that "the LMP Calculation Method is only appropriate when the size of the facility at issue is small, so that other nearby resources would be unaffected by that facility's availability."[28]

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[25] Ex. XLI-___ at 12 (Andrews Direct).
[26] Ex. Xcel-___ at 10 (Detmer Rebuttal).
[27] Ex. Xcel-___ at 9 (Detmer Rebuttal).
[28] Ex. Xcel-___ at 10 (Detmer Rebuttal).

Regarding the justification of the use of the LMP Calculation Method in this case, Mr. Detmer states that "XLI witness Andrews argues that PINGP is small as compared to the size of MISO, in total, and that all the generators in aggregate would have been unaffected by its operation."[29]

In response to this argument, Mr. Detmer states:

> The problem with this argument is that PINGP is not actually a small facility, and the entire MISO footprint is not the appropriate comparison when considering the significance of a unit located in Minnesota. Instead, the MISO segment identified as MISO North is a better reference in this case because constraints in the MISO transmission system frequently impede the flow of energy into and out of MISO North.

Q. What is your evaluation of Mr. Detmer's rebuttal on this point?

A. I disagree with Mr. Detmer that MISO North (as opposed to the entire MISO market) is the appropriate reference. As explained above, the LMPs do not show that there are substantial, sustained constraints in the MISO transmission system that frequently impede the flow of energy into Minnesota. While constraints are clearly present at times, especially in certain locations, they are not the prevalent condition.

[29] Ex. Xcel-___ at 10 (Detmer Rebuttal).

Q. What is Mr. Detmer's next response to Mr. Andrews' proposed LMP Calculation Method that you would like to address?

A. Mr. Detmer notes that Mr. Andrews relies upon "the MISO winter dispatch curve and the modeling done in the Sherco 3 analysis to support his calculations."[30] Mr. Detmer then states that there are three problems with this approach:

- the NSP and MISO generation portfolios have significantly changed since 2011 when the Sherco 3 analysis was completed;
- PINGP is a "must-run" unit thus some additional MISO market sales will occur from PINGP's operation at certain times, while at other times, other resources within the NSP footprint will be displaced; and
- the MISO winter dispatch curve is for all of MISO, which spans fifteen states from Minnesota to Louisiana and part of Manitoba, Canada.

Q. What is your evaluation of Mr. Detmer's rebuttal on this point?

A. I agree with Mr. Detmer that the Sherco 3 analysis is old and that PINGP is different that Sherco 3. However, these facts are not relevant. Mr. Andrews only relies upon the Sherco 3 analysis to demonstrate that the lost net revenues represent the vast majority of the replacement power costs in a prior analysis. From this Mr. Andrews concludes that the LMP calculation method is a reasonable proxy for replacement power costs because lost net revenues are what the LMP Calculation Method captures.

[30] Ex. Xcel-___ at 10-11 (Detmer Rebuttal).

In summary, Mr. Detmer's claims, while true, are not persuasive considering Mr. Andrews' limited use of the Sherco 3 analysis.

Q. What is Mr. Detmer's next response to Mr. Andrews' proposed LMP Calculation Method that you would like to address?

A. Mr. Detmer starts by noting that "XLI witness Andrews argues that the Sherco Unit 3 contested case involved more complex modeling that included the LMP Calculation Method and that that work supports the use of that modeling approach in this case."[31] Mr. Detmer then states that the Sherco Unit 3 contested case "did not include the LMP Calculation Method."[32]

On this point Mr. Andrews' testimony actually stated, "[i]t is my understanding that Xcel took a much more rigorous approach to determine the replacement power costs for Sherco 3, which included calculating a new set of LMPs and using two different production cost models to determine the replacement power costs. Regardless of the methodology used, the results of the analysis, being reproduced below, show the replacement power costs consists of three categories of costs."[33]

From this testimony, it is clear that Mr. Andrews did not claim that the Sherco 3 case involved use of the LMP Calculation Method. Instead, the complex calculations, however they are characterized, resulted in 3 categories of costs. That categorization of costs is what Mr. Andrews relies on.

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[31] Ex. Xcel-___ at 12 (Detmer Rebuttal).
[32] Ex. Xcel-___ at 12-13 (Detmer Rebuttal).
[33] Ex. XLI-___ at 13 (Andrews Direct).

In summary, Mr. Detmer's claims are not persuasive on this point.

V. SUMMARY OF RECOMMENDATIONS

Q. Based on your investigation, what do you conclude?

A. I conclude that although PLEXOs production modeling would customarily be appropriate for modeling incremental power costs, Xcel's modeling here is too unreliable to use. As discussed above, Xcel's modeling assumes transmission system constraints unsupported by real world data. In the absence of reliable PLEXOs modeling, I conclude that the LMP calculation method recommended by Mr. Andrews provides a sufficiently reasonable result for purposes of calculating a replacement power cost refund.

Q. Have you completed your surrebuttal testimony?

A. Yes.

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St. Paul, MN 55101-2145

Professional Background

1996 to present Public Utilities Analyst Coordinator • Minnesota Department of Commerce. Coordinate teams analyzing resource plans, certificates of need, and miscellaneous public policy issues filed with the Minnesota Public Utilities Commission. Testify before the Minnesota Office of Administrative Hearings in contested-case proceedings. A list of related filings analyzed and testimony presented is included below.

1999 to 2005 Board of Governors • MinforMed, L.L.C. Wrote portions of and advised on the economic and business sections of several grant proposals and the 2002 business plan. Named to Board of Directors, March, 2000.

1995 Instructor • University of Nebraska-Omaha. Taught Principles of Macroeconomics.

1993 to 1994 Instructor and Academic Assistant to the Rector • Concordia International University-Estonia. Taught Introduction to Economics. Wrote Student Handbook and Faculty Introduction to Tallinn Handbook.

1993 Instructor • Concordia University-Nebraska. Taught Principles of Microeconomics.

1989 to 1993 Graduate Teaching Assistant • University of Nebraska. Taught Introduction to Economics, Principles of Microeconomics, Principles of Macroeconomics, Current Economic Issues and Intermediate Macroeconomics. Specialized in public policy, economic history and comparative economics.

Education

Doctor of Philosophy, Economics, University of Nebraska, December 1994

Master of Arts, Economics, Mankato State University, March 1989

Bachelor of Arts, Economics, Moorhead State University, May 1987

Bachelor of Science, Accounting, Moorhead State University, May 1987

Testimony in Contested Case Proceedings

Docket No.	Company	Description	Subjects
E002/CN-24-68	Xcel Energy	Prairie Island ISFSI	Generation Alternatives
E002/CN-21-668	Xcel Energy	Monticello ISFSI	Generation Alternatives
G002/GR-21-678	Xcel Energy	Rate Case	Sales to Electric Generators
E002, ET6675/CN-17-184	Xcel Energy, ITC-M	Huntley-Wilmarth 345 kV	Need
E015/AI-17-568	Minnesota Power	Nemadji Trail CC	Resource Plan, Contracts
E015/GR-16-664	Minnesota Power	Rate Case	Avoided Cost, Terms of Service
E015/CN-12-1163	Minnesota Power	Manitoba-Minnesota 500 kV	Alternatives, Policy
ET6675/CN-12-1053	ITC Midwest	Minnesota-Iowa 345 kV	Alternatives, Policy
E002/CN-12-1240	Xcel Energy	Competitive Resource Acquisition	Alternatives
E002/CN-12-113	Xcel Energy	Hollydale 115 kV	Alternatives, Policy
E017/M-10-1082	Otter Tail	Big Stone AQCS	Alternatives
E017/GR-10-239	Otter Tail	Rate Case	Big Stone II Background
E015/PA-09-526	Minnesota Power	Purchase DC Line	Alternatives
E002/CN-08-510	Xcel Energy	Prairie Island ISFSI	Planning, Alternatives, Policy
E002/CN-08-509	Xcel Energy	Prairie Island EPU	Planning, Alternatives, Policy
E002/CN-08-185	Xcel Energy	Monticello EPU	Planning, Alternatives, Policy
E002, ET2/CN-06-1115	Xcel Energy , GRE	CapX 161/230/345 kV	Planning Background, Alternatives, Policy
E002, ET3/CN-04-1176	Xcel, Dairyland	Chisago-Apple R. 115/161 kV	Planning Background, Alternatives, Policy
E017 et al/ CN-05-619	Otter Tail Power, et al	Big Stone-Morris 230 kV Big Stone-Granite Falls 345 kV	Planning Background, Alternatives, Policy
E002/CN-05-123	Xcel Energy	Monticello ISFSI	Planning Background, Alternatives, Policy
E002/CN-04-76	Xcel Energy	Blue Lake CT	Alternatives
IP6339/CN-03-1841	Trimont LLC	Trimont Wind	Settlement-Alternatives
E001/GR-03-767	Interstate Power	Rate Case	Rate of Return
IP6202/CN-02-2006	MMPA	Faribault CC	Settlement, Environmental Report
ET2/CN-02-536	GRE	Plymouth-Maple Gr. 115 kV	Forecasting
E002/CN-01-1958	Xcel Energy	SW Minn. 115/161/345 kV	Forecasting
PL9/CN-01-1092	Lakehead	Clearbrook-Superior Pipeline	Alternatives, Social Consequences
E002/CN-99-1815	Northern States Power	Black Dog CC	Alternatives, Forecasting
ET2/CN-99-976	GRE	Pleasant Valley CT	Forecasting, Environmental Report, Social Consequences
IP3/CN-98-1453	Tenaska, NRG	Lakefield Junction CT	Alternatives, Environmental Report, Social Consequences
PL9/CN-98-327	Lakehead	Clearbrook-Donaldson Pipeline	Alternatives, Social Consequences

Comments in Planning and Resource Acquisition Proceedings

Docket No.	Company	Type	Subjects
ET6125/RP-25-266	Basin	Resource Plan	Establish Process
E002/CN-25-145	Xcel Energy	Need-Generation	All Areas
E015/RP-25-127	Minnesota Power	Resource Plan	Background and Coordination
ET9/RP-24-356	SMMPA	Resource Plan	Background and Coordination
E999/M-25-99	All Electric	Transmission Plan	Ben/Cost Framework
PT7151/CN-24-435	Amazon Data Serv.	Need-Back Up Generation	Exemptions
E017/M-24-404	Otter Tail Power	Acquisition-Solar	All Areas
E999/CI-24-397	All Electric	Planning—MISO PRA	All Areas
E999/CI-24-316	All Electric	Planning—Nobles Substation Congestion	MISO
E002/RP-24-067	Xcel Energy	Resource Plan	Background and Coordination
E002/M-21-590	Xcel Energy	Acquisition-Biomass	Modeling
E111/M-23-420	Dakota Electric	Distribution Plan	Forecast
E015/M-23-258	Minnesota Power	Distribution Plan	Forecast
E017/M-23-380	Otter Tail Power	Distribution Plan	Forecast
E002/M-23-452	Xcel Energy	Distribution Plan	Forecast
E999/M-23-091	All Electric	Transmission Plan	All Areas
E017/CN-23-506	Otter Tail Power	Need-Transmission	Notice and Exemption
ET3/CN-23-504	Dairyland	Need-Transmission	Notice and Exemption
E111/M-23-495	Dakota Electric	Acquisition-Battery Tariff	All Areas
E002/CN-22-532	Xcel Energy	Need-Transmission	Notice and Exemption, Policy
E002, et al/CN-22-538	Xcel Energy, et al	Need-Transmission	All Areas
E015,ET2/CN-22-416	MP, GRE	Need-Transmission	All Areas
E002/CN-22-131	Xcel Energy	Need-Transmission	Need
E002/M-23-119	Xcel Energy	Acquisition-Long Duration Battery Pilot	All Areas
E017/RP-21-339	Otter Tail Power	Resource Plan	All Areas
E002/M-23-342	Xcel Energy	Acquisition-Develop. Wind RFP	All Areas
E002/CN-23-212	Xcel Energy	Acquisition-Firm Dispatchable	Notice and Procedure
E999/M-21-111	All Electric	Transmission Plan	Process Reform
E002/M-22-403	Xcel Energy	Acquisition-Solar RFP	All Areas
ET2/RP-22-075	Great River Energy	Resource Plan	Coordination

Docket No.	Company	Type	Subjects
E,G999/CI-22-624	All Electric & Gas	Planning & Acquisition-Federal Impact on Planning and Need	All Areas
IP7003/CN-19-223	Regal Solar	Need-Solar	Changed Circumstance
E999/CI-22-600	All Electric	Acquisition-Demand Resp. Aggregation	All Areas
E999/CI-22-268	MP, OTP, & Xcel	Acquisition-Demand Response & Fed. Law	All Areas
ET2/GS-22-122	Great River Energy	Generation Siting	CN Requirements
E017/RP-21-339	Otter Tail Power	Acquisition-Dual Fuel	Astoria Dual Fuel
IP7014/CN-19-486	Red Rock Solar	Need-Solar	All Areas
E015/RP-21-033	Minnesota Power	Resource Plan	Forecast, Policy
IP7013/CN-19-408	Big Bend Wind	Need-Wind	All Areas
E002/M-20-891	Xcel Energy	Acquisition-Sherco Solar	All Areas
IP7053/CN-21-112	Hayward Solar	Need-Wind	All Areas
E002/CN-08-510	Xcel Energy	Need-Cask Bidding	All Areas
E999/CI-19-704	All Electric	Baseload Dispatch	All Areas
IP7041/CN-20-764	Byron Solar	Acquisition-Solar	All Areas
E002/M-20-844	Otter Tail Power	Acquisition-Solar	Modeling
E002/M-20-806	Xcel Energy	Acquisition-Wind	All Areas
E002/M-20-620	Xcel Energy	Acquisition-Wind	Modeling
E002/AI-19-810	Xcel Energy	Acquisition-Wind	Economics
E002/RP-19-368	Xcel Energy	Resource Plan	Modeling
E999/CI-19-704	All Electric	Dispatch-Coal	All Areas
E002/M-19-809	Xcel Energy	Dispatch-Coal	Economics
IP7026/CN-20-269	Walleye Wind	Need-Wind	Exemption
E002/M-19-268	Xcel Energy	Acquisition-Wind	All Areas
E002/PA-19-553	Xcel Energy	Acquisition-Wind	Modeling
E002/PA-18-702	Xcel Energy	Acquisition-Gas CC	Economics
E015/M-18-600	Minnesota Power	Acquisition-Wind	All Areas
E015/M-18-545	Minnesota Power	Acquisition-Wind	All Areas
IP6964/CN-16-289	Nobles 2 Power	Need-Wind	All Areas
ET9/RP-17-753	SMMPA	Resource Plan	Modeling
E002/M-17-551	Xcel Energy	Termination-Biomass	Economics
E002/M-17-532	Xcel Energy	Acquisition-RDF	Economics
E002/M-17-531	Xcel Energy	Termination-Landfill	Economics
E002/M-17-530	Xcel Energy	Termination-Biomass	Economics
IP6981/CN-17-306	Dodge County Wind	Need-Wind	Exemption
ET2/RP-17-286	Great River Energy	Resource Plan	Supply

Docket No.	Company	Type	Subjects
E002/M-16-777	Xcel Energy	Acquisition-Wind	Economics
ET10/RP-16-509	Missouri River	Resource Plan	Modeling
E017/RP-16-386	Otter Tail Power	Resource Plan	Modeling
E002/M-16-209	Xcel Energy	Acquisition-Wind	Economics
E002/M-15-962	Xcel Energy	Distribution Plan	All Areas
E015/RP-15-690	Minnesota Power	Resource Plan	Modeling
E002/M-15-330	Xcel Energy	Acquisition-Solar	All Areas
E002/RP-15-021	Xcel Energy	Resource Plan	Modeling
E015/M-14-926	Minnesota Power	Acquisition-Hydro	All Areas
E015/M-14-960	Minnesota Power	Acquisition-Hydro	All Areas
E002/M-14-162	Xcel Energy	Acquisition-Solar	Modeling
ET6/RP-14-536	Minnkota	Resource Plan	Forecasting
E001/RP-14-0077	Interstate Power	Resource Plan	Modeling
E015/RP-13-0053	Minnesota Power	Resource Plan	Modeling
E015/M-12-1349	Minnesota Power	Acquisition-Biomass	Modeling
ET2/CN-12-1235	Great River Energy	Need-Transmission	All Areas
ET3/RP-11-0918	Dairyland	Resource Plan	Supply
E002, ET2/CN-11-0826	Xcel Energy, GRE	Need-Transmission	Alternatives, Policy
ET6133/RP-11-0771	MMPA	Resource Plan	Supply
IP6853, IP6866/CN-11-0471	Black Oak & Getty Wind	Need-Wind	All Areas
E999/M-11-0445	All Electric	Transmission Plan	All Areas
E002/CN-11-0332	Xcel Energy	Need-Transmission	Alternatives, Policy
E002/RP-10-0825	Xcel Energy	Resource Plan	Modeling
ET6/RP-10-0782	Minnkota	Resource Plan	Modeling
E002/CN-10-0694	Xcel Energy	Need-Transmission	Alternatives, Policy
E017/RP-10-0623	Otter Tail Power	Baseload Study	Modeling
E017/RP-10-0623	Otter Tail Power	Resource Plan	Modeling
E002/M-10-0486	Xcel Energy	Acquisition-Digester	Modeling
ET6838/CN-10-0080	Geronimo Wind	Need-Wind	All Areas
E002/CN-09-1390	Xcel Energy	Need-Transmission	Alternatives, Policy
E015/RP-09-1088	Minnesota Power	Baseload Study	Modeling
IP6701/CN-09-1186	National Wind	Need-Wind	All Areas
IP6830/CN-09-1110	Geronimo Wind	Need-Wind	All Areas
E015/RP-09-1088	Minnesota Power	Resource Plan	Modeling
E002/M-09-0821	Xcel Energy	Acquisition-Biomass	Modeling
E999/M-09-0602	All Electric	Transmission Plan	All Areas

Docket No.	Company	Type	Subjects
ET9/RP-09-0536	SMMPA	Resource Plan	Modeling
E015/PA-09-0526	Minnesota Power	Acquisition-Transmission	Need, Alternatives
E002/CN-08-0992	Xcel Energy	Need-Transmission	All Areas
IP6688/CN-08-0961	EcoHarmony Wind	Need-Wind	All Areas
ET6125/RP-08-0846	Basin	Resource Plan	Supply
ET2/RP-08-0784	Great River Energy	Resource Plan	Supply
E001/RP-08-0673	Interstate Power	Resource Plan	Modeling
E002/RP-07-1572	Xcel Energy	Resource Plan	Modeling, Nuclear
E017, et al/CN-07-1222	MP, OTP, Minnkota	Need-Transmission	Alternatives, Policy
E999/M-07-1028	All Electric	Transmission Plan	All Areas
E017/CN-06-0677	Otter Tail Power	Need-Transmission	All Areas
ET9/RP-06-0605	SMMPA	Resource Plan	Supply
E001/RP-05-2029	Interstate Power	Resource Plan	Supply
E999/TL-05-1739	GRE, MP	Need-Transmission	All Areas
E999/TL-05-1739	All Electric	Transmission Plan	All Areas
ET10/RP-05-1102	Missouri River	Resource Plan	Modeling
ET2/RP-05-1100	Great River Energy	Resource Plan	Supply
E017/RP-05-0968	Otter Tail Power	Resource Plan	Supply
E002/RP-04-1752	Xcel Energy	Resource Plan	Modeling, Bidding
E015/RP-04-0865	Minnesota Power	Resource Plan	DSM, Supply
E002/M-04-0091	Xcel Energy	Acquisition-Biomass	All Areas
E999/TL-03-1752	All Electric	Transmission Plan	All Areas
ET2/RP-03-0974	Great River Energy	Resource Plan	DSM
E002/M-03-0547	Xcel Energy	Acquisition-Hydro	All Areas
E002/RP-02-2065	Xcel Energy	Resource Plan	DSM, Nuclear
ET6/RP-02-1145	Minnkota	Resource Plan	Forecast, Contingency
E999/TL-01-0961	All Electric	Transmission Plan	All Areas
ET2/RP-01-0160	Great River Energy	Resource Plan	DSM
ET3/RP-00-1619	Dairyland	Resource Plan	All Areas
ET9/RP-00-0863	SMMPA	Resource Plan	Forecasting
E002/RP-00-0787	Xcel Energy	Resource Plan	DSM, Nuclear
E015/RP-99-1543	Minnesota Power	Resource Plan	DSM, Forecast
E017/RP-99-0909	Otter Tail Power	Resource Plan	Rate Design
ET10/RP-98-0938	Missouri River	Resource Plan	Supply, Rate Design
ET2, ET3/RP-98-0366	CPA/Dairyland	Resource Plan	Supply
E002/RP-98-0032	NSP	Resource Plan	Supply, Nuclear
E015/RP-97-1545	Minnesota Power	Resource Plan	DSM

Docket No.	Company	Type	Subjects
E001/RP-97-0955	Interstate Power	Resource Plan	Supply
ET9/RP-97-0954	SMMPA	Resource Plan	Forecasting
ET7/RP-97-0001	United Power	Resource Plan	DSM