BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Xcel Energy's Petition for Approval of its 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges	)))))	**DOCKET NO. E-002/AA-22-179)** **CAH File No. 21-2500-40336**

Direct Testimony and Schedule of

Brian C. Andrews

On behalf of

Xcel Large Industrials

July 2, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11875

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Table of Contents for the
Direct Testimony of Brian C. Andrews

Page

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Direct Testimony of Brian C. Andrews

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A This information is included in Schedule 1 to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of the Xcel Large Industrials ("XLI").

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A The purpose of my Direct Testimony is to provide my opinion on the reasonableness of Xcel Energy's ("Xcel") estimate of the replacement power costs due to the outage of the Prairie Island Nuclear Generating Plant ("PINGP") during the period of October 19, 2023 – March 1, 2024. Xcel's production cost modeling approach to determine these costs is concerning. I will address these concerns and explain my opinion that Xcel has significantly understated the replacement power costs for the outage at PINGP.

I note that I am only addressing issues I have uncovered with the replacement power cost portion of Xcel's proposed refund. My silence with respect to any other components of the refund or any other issues should not be construed as an endorsement. And because discovery continues, I reserve the right to further supplement or modify my testimony in this proceeding.

II. SUMMARY

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A Xcel's PLEXOS modeling is not an accurate representation of the replacement power costs associated with the outage at PINGP. The outputs that have been provided for the PLEXOS modeling are not rational. As I will demonstrate, 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 have been largely unchanged. This means that a more accurate representation of the replacement power costs can be determined with a simpler approach. This simpler approach is one that determines the net revenue that would have been earned had the resource been operating as usual. Xcel has conducted this analysis and shows that the replacement power costs are **[TRADE SECRET DATA BEGINS . . .** [redacted] **.. . . TRADE SECRET DATA ENDS]** Xcel's PLEXOS modeling understates the replacement power cost by at least **[TRADE SECRET DATA BEGINS . . .** [redacted] **. . . . TRADE SECRET DATA ENDS]** At this time, I conclude that the Minnesota allocated share of the replacement power costs for the PINGP outage are no less than **[TRADE SECRET DATA BEGINS . . .** [redacted] **. . . TRADE SECRET DATA ENDS]** and likely could be higher.

III. REPLACEMENT POWER COSTS

Q HOW HAS XCEL DETERMINED THE REPLACEMENT POWER COSTS ASSOCIATED WITH THE OUTAGE AT PINGP?

A Xcel used the production cost model software, PLEXOS, to estimate the replacement power costs due to the outage at PINGP. Xcel's witness Mr. Detmer provides a single question and answer explaining the process used. He explains that to assess the replacement power cost, PLEXOS was used to determine a base case that reflects actual operation without PINGP, incorporating real data on unit availability, fuel costs, wind generation, customer loads and MISO's market prices. Once the base case was calibrated to actual operations, Xcel's total system costs were extracted from the model. Then, a "change" case was created that made PINGP available for generation during the study period. The difference in cost between the base case and the change case was $34.3 million allocated to the Minnesota jurisdiction.

Q ARE YOU FAMILIAR WITH PLEXOS AND PRODUCTION COST MODELING SOFTWARE?

A Yes. I was trained on PLEXOS in 2014 as the software was gaining popularity in the industry. Further, I have used the production cost modeling software, RealTime, in other projects over my career, specifically to support net power costs in electric utility rate cases. I am also quite familiar with other utility planning software tools such as Encompass, Strategist, Aurora, and others.

Q HAS XCEL PROVIDED ANY DEMONSTRATION THAT ITS BASE CASE IS AN ACCURATE REPRESENTATION OF ITS ACTUAL COSTS?

A No. 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. Further, based on my review of the PLEXOS workpapers, Xcel's calibration essentially forced the base case run to make no dispatch decisions in the base case, but instead forced the model to run the generating units to align with their actual output. This does not tell us that the base case run is an accurate representation of Xcel's actual power costs during the study period.

Q HAVE YOU REVIEWED THE INPUT AND OUTPUT FILES THAT XCEL PROVIDED FOR ITS PLEXOS MODELING?

A Yes. For the 2023 period, Xcel provided these input and output files as Workpapers 1 and 2 to their July 30, 2024 Reply Comments in MPUC Docket No. E002/AA-twenty-two-179 (Exhibit__(ADK-1), Schedule 2). The 2024 input and output files were provided in response to DOC IR 52. These documents are Excel workbooks.

Q WHAT DOES THE 2023 PLEXOS INPUT FILE SHOW?

A The 2023 PLEXOS input files provide data on generator properties, fuel prices and properties, hourly system load, and hourly LMP prices.

Q WHAT DOES THE 2024 PLEXOS INPUT FILE SHOW?

A The 2024 PLEXOS input files provide data on generator properties, fuel prices and properties, actual hourly generation output, including MISO purchases and sales, and wind curtailment. The hourly generation output appears to be the actual data for 52 generators from 1/1/2023 through 4/30/2024.

Q HOW ARE THE 2023 AND 2024 INPUT FILES DIFFERENT?

A The 2023 input files contain LMPs, and the 2024 file does not. The 2024 input file contains actual generator output and the 2023 file does not. It is not clear from these input files if the 2023 and 2024 analyses were conducted in the same manner.

Q WHAT DOES THE 2023 PLEXOS OUTPUT FILE SHOW?

A The 2023 PLEXOS output files provide the output of 53 generators, plus MISO sales, purchases, and wind curtailments for the base and change cases. There is a tab that provides the hourly delta between the base and change cases for each of the 53 generators and the MISO sales, purchases, and wind curtailments. There is also a tab that shows the calculated net change in power costs between the two scenarios, which supports Xcel's monthly replacement costs.

Q DOES THE 2024 OUTPUT FILE SHOW SIMILAR INFORMATION?

A The 2024 PLEXOS output files provide somewhat similar information; however there are only 50 generators, and the MISO sales, purchases and wind curtailments are not shown. There is also a tab which I believe is the LMP method of calculating the replacement power cost during 2024.

Q DO YOU HAVE CONCERNS WITH THE OUTPUTS OF THE 2023 AND 2024 PLEXOS RUNS?

A Yes. To me, the results do not make much sense. Because Xcel is part of the MISO footprint, a system with 191 gigawatts ("GW") of installed generation capacity and loads averaging 72.6 GW at the time of the outage, I would not expect that the addition of the PINGP generation to the market to have much impact on LMPs. Because all load and generation in MISO clears at the market prices, a very small change in LMPs should have very little impact on the dispatch of Xcel's other generators. These output files show that the generation coming from Xcel's combined cycle ("CC") and coal plants are changing drastically, with some having generation output during the study period reduced by as much as 52% and others increasing by 49%. This likely means that in the base case, generation dispatch was fixed at actual output which in reality was MISO's dispatch based on actual LMPs, but in the change case, PLEXOS dispatched all the Xcel generators to a single LMP input to the model.

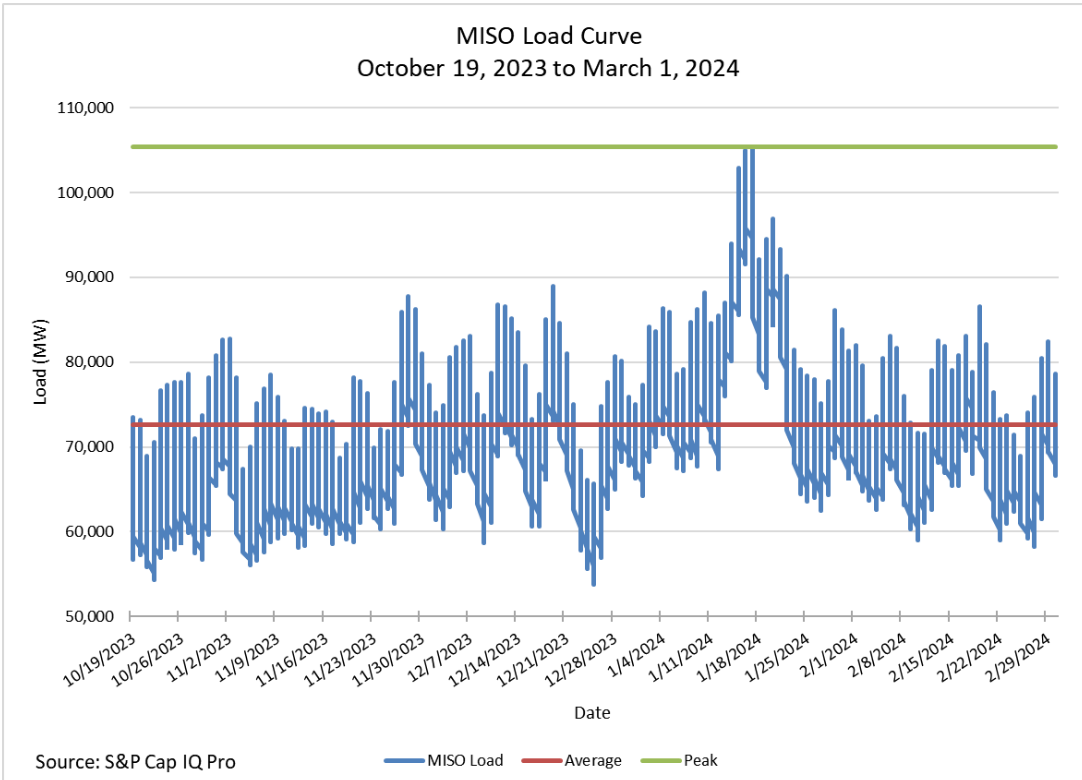
Another extremely alarming issue is that in the 2023 output file, the only file that contains this data, there is no change at all to the MISO sales and purchases. This modeling seems to indicate that Xcel operates in a bubble with little connection to the larger MISO system, which is not how a MISO market participant operates. As I will explain, I would expect that the outage of PINGP would have nearly negligible effect on LMPs, thus, the only real changes to Xcel's system dispatch would be an increase of sales in hours in which sales actually occurred, and a decrease of MISO purchases in hours in which actual purchases occurred, due to the additional energy output from PINGP.

The net effect of all of this should be that a more accurate estimate of the replacement power cost for the outage at PINGP is the net revenue (generation times LMPs, less fuel and operating cost) that would have been earned had PINGP been available.

Q PLEASE EXPLAIN WHY YOU WOULD NOT EXPECT THE ADDITION OR REMOVAL OF PINGP FROM THE MARKET TO HAVE A MEANINGFUL EFFECT ON LMPs.

A Again, Xcel is part of MISO, a combined system comprised of 15 U.S. states and Manitoba, Canada. MISO is operated as a single system, with generators dispatched to meet load and minimize the system cost in every hour, subject to generator parameters and transmission constraints. In December 2023, MISO contained 2,956 generators with an installed capacity of 191 GW. The outage of PINGP would represent just 0.5% of the MISO installed capacity. Furthermore, the loads during this outage were relatively low, as demonstrated in Figure 1 below, which shows the MISO load from 10/19/2023 through 3/1/2024. During this period, the peak load was 105.4 GW on 1/17/2024 and the average load during this period was 72.6 GW. Low loading periods result in generally stable LMPs, which I will explain further.

FIGURE 1: MISO LOAD DURING PINGP OUTAGE



Q WHY DOES LOW LOAD RESULT IN STABLE LMPs?

A Generally, LMPs are determined by basic principles of supply and demand. When loads are low, there is a significant amount of low-cost generation that can supply power to that load. When loads get higher, the costs associated with the generation that is available to meet the higher demand are more costly, as the lower cost generation is already in use. The LMP is at the margin, meaning the last generator that was dispatched to meet load sets the LMP. Figure 2 shows the MISO dispatch curve that existed during Winter 2024.

FIGURE 2: MISO DISPATCH CURVE WINTER 2024

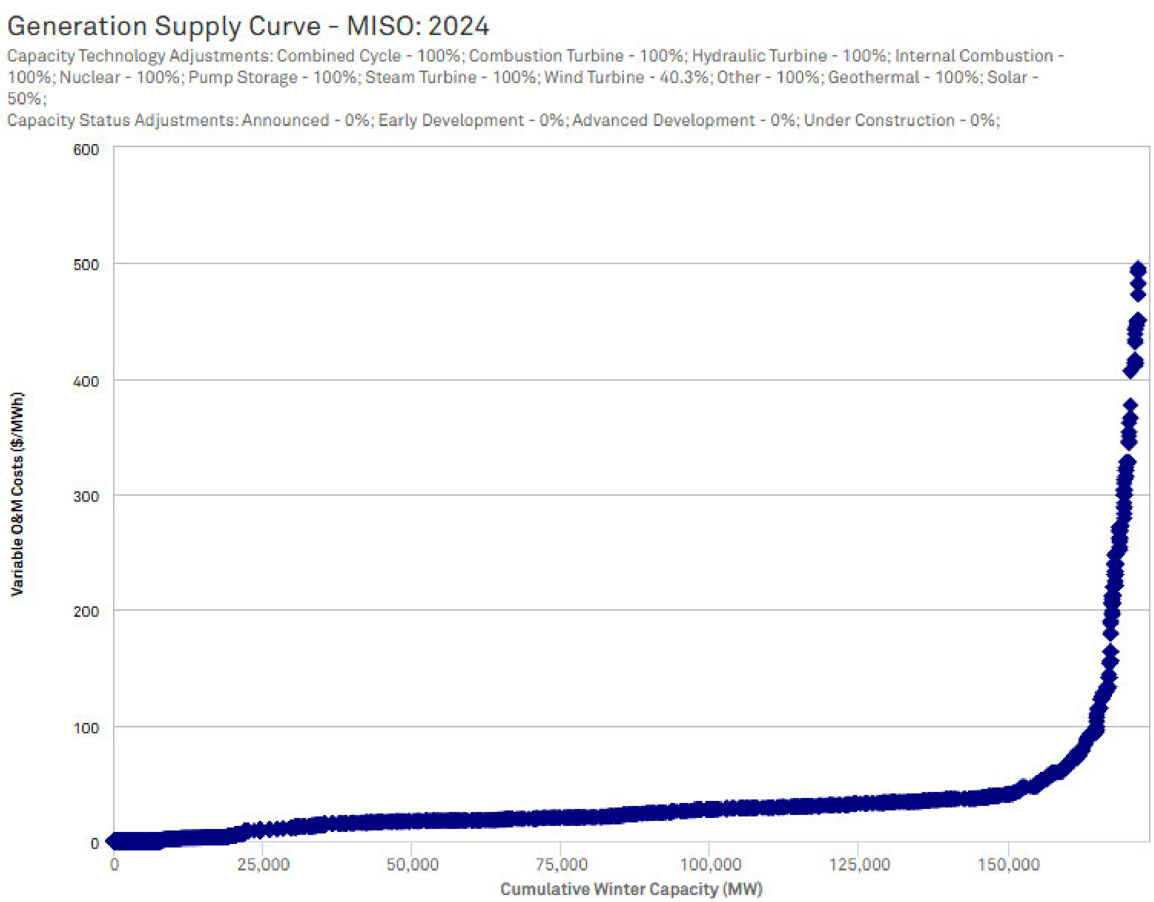


Figure 2 above can be interpreted to show what the LMPs were based on a given load. During the outage, the average load was 72.6 GW. On this generation supply curve, the LMP (variable Operation and Maintenance ("O&M") of the last generator to serve load) would be roughly $20.18/megawatthours ("MWh"). Moving up the generation supply curve by 1.1 GW of the PINGP capacity would only move the variable O&M of the marginal generating unit by $0.02/MWh. Therefore, on average, I would expect that the loss of PINGP resulted in an increase in LMPs of approximately $0.02. At peak loading, which was on 1/17/2024, the demand was 105.4 GW. On the generation supply curve, the marginal unit was $28.29/MWh. Moving up the generation supply curve by 1.1 GW, would increase the cost of the marginal unit by just $0.01. All this information indicates that the removal of PINGP should not have had any significant impact on LMPs.

Q IF THE OUTAGE OF PINGP HAD NO MAJOR EFFECT ON LMPs, WOULD YOU EXPECT XCEL'S OTHER GENERATING UNITS TO HAVE ANY DRASTIC CHANGE IN THEIR OUTPUT?

A I would not. Generally, generators are dispatched above minimum operating levels when they can make a profit. If there is little to no change to LMPs, there should be little to no change to the output from any of the generators on Xcel's system. Because Xcel is just one piece of the much larger MISO system, my expectation is that bringing PINGP back online, which is a very low variable cost resource, results in nearly all of that energy going to increasing Xcel's sales to the MISO market and reducing purchases from MISO. All the other generators would operate much the same as they actually did.

Q WHY WOULD IT MATTER IF LMPs ARE RELATIVELY UNCHANGED AND XCEL'S OTHER GENERATING UNITS WOULD'VE HAD THE SAME DISPATCH IF PINGP HAD BEEN AVAILABLE, BUT FOR THE OUTAGE?

A It matters because the analysis necessary to determine the replacement power costs becomes much simpler. If all of the PINGP generation would be going to increase MISO sales, or reduce MISO purchases, then the answer to the replacement power cost problem is simply the hourly generation that would have occurred had the outage not occurred times LMPs, less the fuel and operating cost.

Q HAS XCEL CONDUCTED AN ANALYSIS BASED ON LMPs?

A Yes. For 2023, Xcel conducted the LMP Calculation Method, which is shown in Mr. Krug's Schedule 2.0. It shows that the 2023 replacement power cost based on the LMP method to be **[TRADE SECRET DATA BEGINS . . .** [redacted] **. . . . TRADE SECRET DATA ENDS]** The 2024 analysis was provided in the 2024 PLEXOS output files, produced in response to DOC IR 052, which shows a 2024 replacement power cost of **[TRADE SECRET DATA BEGINS . . .** [redacted] **. . . . TRADE SECRET DATA ENDS]** In total these calculations show that the replacement power cost for the outage at PINGP was **[TRADE SECRET DATA BEGINS . . .** [redacted] **. . . . TRADE SECRET DATA ENDS]** When allocated to Minnesota, this replacement cost would be **[TRADE SECRET DATA BEGINS . . .** [redacted] **. . . TRADE SECRET DATA ENDS]** a substantial increase to Xcel's $34.3 million that it supports with its PLEXOS modeling.

Q HAVE YOU VERIFIED THE ACCURACY OF THE LMP METHOD CALCULATIONS?

A Yes. I have conducted a simple analysis that determined the net revenue lost due to the outage at PINGP. To conduct this analysis, I utilized the hourly output for both PINGP Units 1 and 2, that were contained in the PLEXOS output files, the actual MISO

Day-Ahead LMPs for the PINGP node, and the variable fuel and operating costs that were contained in Xcel's PLEXOS input files. This analysis produced a replacement power cost of **[TRADE SECRET DATA BEGINS . . .** [redacted], **. . . TRADE SECRET DATA ENDS]** which is less than 1% different than what Xcel has calculated. I interpret this to mean that Xcel has calculated the replacement cost using the LMP method accurately.

Q DO OTHER REPLACEMENT POWER CASES SUPPORT THIS IDEA THAT THE REPLACEMENT POWER COSTS SHOULD BE DERIVED USING THE LMP METHOD?

A Yes, I believe Xcel's Sherco 3 replacement power cost proceeding supports the use of the LMP method.[1] The results of Xcel's study that was conducted in that matter, as part of Xcel's litigation with General Electric ("GE"), clearly demonstrate that the answer to the replacement power cost question is rather clear. It 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.

[1] *See generally In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, et al.*, Docket Nos. E002/GR-12-961, et al.

FIGURE 3:[2] CALCULATION OF REPLACEMENT POWER COSTS IN XCEL'S SHERCO 3 LITIGATION

Damage Elements	Amount	Interest[42]	Total
Loss Of Use			
Lost Net Revenue From Sherco 3	$ 39,887,518	$ 15,069,934	$ 54,957,452
Increased Expense Of NSP Purchases	106,620,753	39,420,367	146,041,120
Increased Net Revenue From Other NSP Resources *(Offset)*	(101,125,865)	(37,646,358)	(138,772,223)
Subtotal Loss Of Use	**$ 45,382,406**	**$ 16,843,943**	**$ 62,226,349**

These three categories of costs are the:

1) lost net revenue from the unit,

2) increased expense of making more purchases from the market, and

3) additional net revenue from other generating resources (offset).

What is extremely telling from the data in Figure 3 above, is that the increased expense from purchases, and the offset for increased net revenue from the other generators nearly entirely cancel each other out. This essentially leaves the lost net revenue from Sherco 3 as the vast majority of the replacement power costs. Indeed, the $39.9 million of lost net revenue from Sherco 3 represents roughly 88% of the replacement power costs from the GE Litigation study. The lost net revenue is essentially an LMP calculation. This tells us two things. First, the LMP calculation method is a reasonable proxy for replacement power costs. Second, the LMP calculation method may actually understate the true replacement power costs. Based on this, I cannot, at this time, agree that the

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[2] Reproduced from Figure 2 of Department of Commerce witness Matthew J King's Direct Testimony. *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, et al.*, Docket Nos. E002/GR-12-961 et al, Direct Testimony of Matthew J. King (June 16, 2023) (eDocket No. 20236-196625-49).

replacement power costs for the PINGP outage, as calculated by PLEXOS, are reasonable since those results are significantly lower than the replacement power costs that can be estimated using the LMP calculation method.

IV. CONCLUSION

Q PLEASE STATE YOUR CONCLUSION?

A Xcel's PLEXOS modeling is an accurate representation of the replacement power costs associated with the outage at PINGP. The outputs that have been provided for the PLEXOS modeling are rationale results. As I have demonstrated, the outage at PINGP should not have had any major effect on the LMPs, therefore, generation output of Xcel's other resources should've been largely unchanged. This means that a more accurate representation of the replacement power costs can be determined with a simpler approach. This simpler approach is one that determines the net revenue that would have been earned had the resource been operating as usual. Xcel has conducted this analysis and shows that the replacement power costs are **[TRADE SECRET DATA BEGINS . . .** [redacted]**. . . . TRADE SECRET DATA ENDS]** Xcel's PLEXOS modeling understates the replacement power cost by at least **[TRADE SECRET DATA BEGINS . . .** [redacted]**. . . . TRADE SECRET DATA ENDS]** At this time, I concluded that the Minnesota allocated share of replacement power costs for the PINGP outage are no less than **[TRADE SECRET DATA BEGINS . . .** [redacted], **. . . TRADE SECRET DATA ENDS]** and likely could be higher.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

SCHEDULE 1

Direct Testimony of Brian C. Andrews

Qualifications of Brian C. Andrews

QUALIFICATIONS OF BRIAN C. ANDREWS

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As a Principal at BAI, and as an Associate, Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, Virginia, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

SCHEDULE 2

Direct Testimony of Brian C. Andrews

Information Request DOC IR 052 (PUBLIC)

Attachments A and B
Not Included
(TRADE SECRET IN THEIR ENTIRETY)

SCHEDULE 3

Direct Testimony of Brian C. Andrews

BCA WP-1: Index

SCHEDULE 4

Direct Testimony of Brian C. Andrews

BCA WP-2 (TRADE SECRET): Prairie Island LMP Replacement Cost Analysis Not Included (TRADE SECRET IN ITS ENTIRETY)

SCHEDULE 5

Direct Testimony of Brian C. Andrews

BCA WP-3: MISO Load Data for 10/19/2023 to 3/1/2024

SCHEDULE 6

Direct Testimony of Brian C. Andrews

BCA WP-4: MISO Generation Supply Curve for Winter 2024

SCHEDULE 7

Direct Testimony of Brian C. Andrews

BCA WP-5: MISO Fact Sheet – January 2024