BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF THE APPLICATION OF XCEL ENERGY AND ITC MIDWEST LLC FOR A CERTIFICATE OF NEED FOR THE HUNTLEY-WILMARTH 345 KV TRANSMISSION LINE PROJECT	MPUC Docket No. ET6675/CN-17-184 OAH Docket No. 82-2500-35157

DIRECT TESTIMONY AND ATTACHMENTS OF MARK A. JOHNSON

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

COST ALLOCATIONS AND COST RECOVERY ISSUES

NOVEMBER 7, 2018

DIRECT TESTIMONY AND ATTACHMENTS OF MARK A. JOHNSON
IN THE MATTER OF THE APPLICATION OF XCEL ENERGY AND ITC MIDWEST LLC FOR A CERTIFICATE OF NEED FOR THE HUNTLEY-WILMARTH 345 KV TRANSMISSION LINE PROJECT

DOCKET NOS. E002, ET6675/CN-17-184
OAH DOCKET NO. 82-2500-35157

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Mark A. Johnson. I am employed as a Public Utilities Analyst Coordinator - Financial by the Minnesota Department of Commerce, Division of Energy Resources (DOC-DER). My business address is 85 7th Place East, Suite 500, St. Paul, Minnesota 55101-2198.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in accounting in 1988 from the University of Minnesota. In 1992, I received an M.B.A. degree from the University of St. Thomas with an emphasis in management. I also maintain an active Certified Public Accountant (CPA) License in the state of Minnesota.

Q. What is your business experience?

A. My business background includes over three years of experience with the Minnesota Office of the State Auditor performing audits of local governments. I also have two years of experience as a staff accountant with a CPA firm conducting audits of businesses, preparing financial statements, and preparing corporate and individual tax returns.

Since accepting the position of Financial Analyst at the Department of Commerce over twelve years ago, I have worked on numerous issues pertaining to regulatory finances and ratemaking. In addition, I have filed testimony in numerous contested cases. Attached as DOC-DER Ex.___ at MAJ-1 (Johnson Direct) is a complete list of contested cases where I have filed testimony on behalf of the DOC-DER.

II. PURPOSE

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to assist the Minnesota Public Utilities Commission (Commission) in evaluating the financial impacts of Xcel Energy (Xcel) and ITC Midwest, LLC's (ITCM) (collectively, the Applicants) January 17, 2018 *Application to the Minnesota Public Utilities Commission for the Huntley –Wilmarth 345 kV Transmission Line Project* (Petition).

III. SUMMARY OF THE PROPOSED PROJECT

Q. Please summarize the facilities proposed in the Petition by Xcel Energy and ITC Midwest LLC.

A. The Applicants propose to construct a 50-mile 345 kilovolt (kV) transmission line between Xcel Energy's Wilmarth Substation north of Mankato, Minnesota and ITCM's Huntley Substation south of Winnebago, Minnesota (Project). Xcel and ITC Midwest would also make modifications to their existing, and respectively owned, Wilmarth Substation and Huntley Substation to accommodate the proposed 345 kV transmission line.

Q. How would the ownership of the proposed Project be structured?

A. Xcel and ITCM would own the proposed Project jointly as tenants in common. The equipment and improvements associated with the Wilmarth Substation would be owned solely by Xcel. The equipment and improvements associated with the Huntley Substation would be owned solely by ITCM.

IV. PROPOSED PROJECTS COSTS, MISO ALLOCATIONS, AND COST RECOVERY

A. PROPOSED PROJECT COSTS

Q. What are the estimated costs of the proposed Project?

A. According to the Petition, the Midcontinent Independent System Operator's, Inc. (MISO) estimated costs for the proposed Project ranged from $88 million to $108 million (2016 dollars), which resulted in a benefit-to-cost ratio range of 1.51 to 1.86 under MISO's 2016 Transmission Expansion Plan (MTEP16). The Project was included in Appendix A of MTEP16 at an estimated cost of $108 million. Applicants Ex.___ at 31 (Petition).

The Applicants also stated that their estimated costs for the proposed Project ranged from $105.8 million to $138.0 million (2016 dollars) depending on the route approved by the Commission. Applicants Ex.___ at 9 (Stevenson Direct). The following table shows the Applicants' estimated range of Project costs in 2016 dollars:

Table 1: Total Project Cost Estimates (2016$)[1]

Design Option	Route Option			
	Purple Route (West Route) ($Millions)	Green Route (Middle Route) ($Millions)	Red Route (Middle Route) ($Millions)	Blue Route (East Route) ($Millions)
Single-Circuit H-Frame		$109.0		
Single-Circuit Monopole		$121.3		
Single-Circuit Parallel H-frame	$105.8			
Single-Circuit Parallel Monopole	$121.7			
Double-Circuit Monopole and Single-Circuit H-Frame			$135.2	$123.7
Double-Circuit Monopole and Single-Circuit Monopole	$137.9		$138.0	$135.8

Q. What is included in these cost estimates?

A. The Applicants' cost estimates include all transmission line costs, right-of-way costs, risk contingencies for transmission line and cost for substation modifications at both the Wilmarth and Huntley substations, and Allowance for Funds Used During Construction (AFUDC). Applicants Ex.___ at 9 (Stevenson Direct).

Q. Why do the Applicants have different cost estimates for the proposed Project than MISO?

A. Applicants stated that:

> As evidenced by the discussion above, MISO's and the Applicants' cost estimation processes are different. Whereas MISO employs a standard set of costs to compile its estimate, Applicants relied on site specific cost

[1] Applicants Ex.___ at 9-10 (Stevenson Direct).

> information as well as cost information gathered from recent transmission projects. For instance, MISO's right-of-way costs were calculated on a per-mile basis with costs based on USDA pasture land prices. In contrast, Applicants estimated right-of-way costs for each route by classifying the property types crossed by each of the proposed routes and then analyzing and applying general market value data for each property type in the Project area.

Applicants Ex.___ at 36 (Petition).

Q. Did the Applicants later revise their estimated Project costs in direct testimony?

A. Yes. Based on the route and segment alternatives proposed during the scoping process for the Environmental Impact Statement, the Applicants stated that their estimated range of costs increased to $104.8 million to $160.7 million (2016 dollars). Applicants Ex.___ at 8 (Neidermire Direct). The following table shows the Applicants' revised estimated range of Project costs based on the route and segment alternatives:

Table 2: Revised Total Project Cost Estimates (2016$)[2]

Purple		Green		Red		Blue		Purple-E-Red	
Low	High	Low	High	Low	High	Low	High	Low	High
$ 104.8	$ 147.3	$ 108.2	$ 124.8	$ 134.4	$ 143.8	$ 123.7	$ 142.5	$ 157.0	$ 160.7

Q Do you have any concerns with the Applicants' estimated Project costs at this time?

A. No. The Applicants' updated costs for the proposed Project reflect the best information available to decide whether the proposed Project is reasonable compared to

[2] Applicants Ex.___ AWS-6, at 3 (Stevenson Direct).

alternatives, including any other proposed project since this process explicitly allowed other projects to file alternative proposals, per the May 25, 2018 First Prehearing Order.

B. MARKET EFFICIENCY PROJECTS AND MISO COST ALLOCATIONS

Q. What are Market Efficiency Projects?

A. Market Efficiency Projects (MEPs) are projects that MISO determined are needed to reduce transmission system congestion and improve the efficiency of MISO's energy markets, which should result in lower wholesale energy costs if built. To qualify as an MEP, a project must meet the following criteria:

1. Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher;

2. The benefit-to-cost ratio of the candidate project must meet or exceed 1.25; and

3. The total project costs must exceed $5 million.

The MISO Board of Directors approved the Huntley-Wilmarth Project as an MEP in December 2016 as part of its MTEP16 report. Applicants Ex.___ at 5 (Neidermire Direct).

Q. How are MEP costs allocated under MISO tariffs?

A. The Applicants stated that:

> Under Attachment FF of the MISO Tariff, recovery of the Project costs will be governed by Attachment GG and Schedules 26 of the MISO Tariff. The MISO Tariff provides that 20 percent of the Project costs for an MEP are allocated to each pricing zone in MISO Classic based on load ratio share (LRS). The remaining 80 percent of the

costs of an MEP are allocated to pricing zones based on the distribution of positive APC [Adjusted Production Cost] savings to the Local Resource Zones.

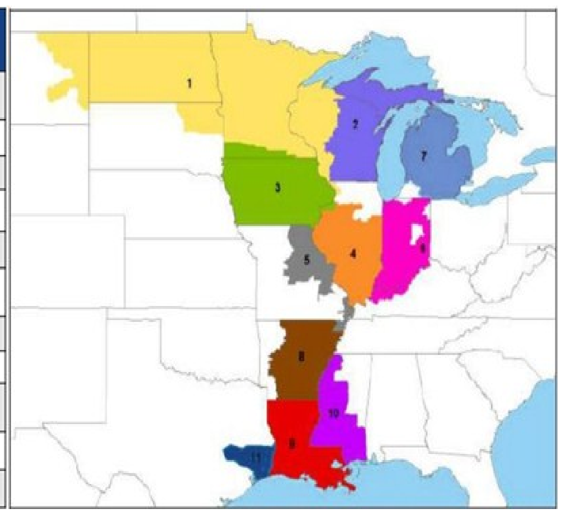
Applicants Ex.___ at 37 (Petition) (footnotes omitted).

Q. What is MISO Classic?

A. MISO Classic generally refers to the northern half of the MISO footprint and includes Local Resource Zones (also referred to as Cost Allocation Zones) 1-7. The following graph shows MISO's Cost Allocation Zones and related Transmission Pricing Zones:

Graph 1 – MISO Cost Allocation Zones and Transmission Pricing Zones

Cost Allocation Zones	Transmission Pricing Zone(s)
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ATC
3	ITCM, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DEI, HE, IPL, NIPS, VECT
7	METC, ITC
8	EATO
9	CLCE, ELTO, ENTO, LAFA
10	EMTO, SME
11	ETTO



Thus, under the MISO Tariff, 20 percent of the Project's costs would be allocated to the Transmission Pricing Zones located in Cost Allocation Zones 1-7 based on their respective load ratio share.[3] The amounts allocated to the Transmission Pricing Zones

[3] Technically, project capital and operation and maintenance costs are first converted into annual revenue requirements before being allocated under MISO Tariffs. For purposes of this testimony, the allocation of project costs is intended to be synonymous with the allocation of revenue requirements.

would then be allocated to each utility based on their respective load ratio share within these zones. Applicants Ex.___ at 38-39, Tables 4 and 5 (Petition).

Q. How would the remaining 80 percent of the Project costs be allocated under the MISO Tariff?

A. The remaining 80 percent costs of the Project would be allocated to MISO's Cost Allocation Zones based on the distribution of APC savings to the Cost Allocation Zones. As shown in the Petition, the remaining 80 percent would be allocated to MISO Cost Allocation Zones 1, 3, and 4. The amounts allocated to MISO Cost Allocation Zones 1, 3, and 4, would then be allocated to the Transmission Pricing Zones based on their respective load ratio share. Finally, the amounts allocated to the Transmission Pricing Zones will would then be allocated to each utility based on their respective load ratio share within these zones. Applicants Ex.___ at 38-39, Tables 4 and 5 (Petition).

Q. How much of the Project's costs would be allocated to Xcel Energy?

A. Since Xcel Energy has load in six different MISO Transmission Pricing Zones, Xcel Energy would be allocated a portion of the Project costs from six different Transmission Pricing Zones based on their respective load ratio share in each Transmission Pricing Zone. Applicants estimated that Xcel Energy would be allocated approximately 16.96 percent of the Project's costs under Schedule 26 of the MISO Tariffs. Applicants Ex.___ at 39, Table 5 (Petition).

Q. How much of the Project's costs would be allocated to ITCM?

A. None. Since ITCM does not have any load in the MISO Classic area, ITCM would not be allocated any of the Project's costs. Moreover, any Project costs that are allocated to ITCM's Transmission Pricing Zone would be allocated to the utilities with load in ITCM's Transmission Pricing Zone.

Q. Would other Minnesota regulated utilities also be assigned a share of the Project's costs under MISO Schedule 26?

A. Yes. I note that any Minnesota regulated utility with load located within one of the Transmission Pricing Zones shown on page 38, Table 4 of the Petition would also be allocated a share of the Project's costs. However, I expect that other Minnesota regulated utilities' shares of the Project's costs would be significantly lower than Xcel's 16.96 percent share of the costs, due to their smaller size and load.

Q. Would Xcel and ITCM be allocated any of the revenues associated with the Project that are collected under MISO Schedule 26?

A. Yes. Xcel and ITCM would receive the revenues collected under MISO Schedule 26 that are associated with their respective ownership interest in the Project. MISO Schedule 26 revenues are revenues that Xcel and ITCM receive from MISO for use of the proposed Project.

Q. Overall, do you agree with the Applicants' description as to how MEP costs are allocated under MISO Tariffs?

A. Yes.

C. COST RECOVERY

Q. Generally speaking, how do Minnesota's rate-regulated utilities recover transmission project costs from ratepayers?

A. For any Minnesota rate-regulated utility that owns a transmission project, the transmission project's capital and operation and maintenance costs are converted into Minnesota annual revenue requirements and recovered from retail ratepayers through base rates in rate cases or transmission cost recovery riders (transmission riders), which are then reflected on monthly utility bills for retail ratepayers.

Q. How do Minnesota's rate-regulated utilities recover MISO Schedule 26 costs and revenues from ratepayers?

A. Generally speaking, Minnesota's rate-regulated utilities include and recover MISO Schedule 26 costs net of revenues from ratepayers through transmission riders that are reflected on monthly utility bills. The Minnesota Transmission Cost Recovery Statute specifically allows utilities to include these costs in their annual transmission riders and requires that such costs be offset by revenues.[4]

---

[4] Minn. Stat. § 216B.16, subd 7b(b)(2).

Q. Are Minnesota rate-regulated utilities also required to include offsetting MISO Schedule 26 revenues in their transmission riders?

A. Yes. Minnesota Statute §216B.16, subd. 7b(b)(2) requires utilities to offset MISO costs with MISO revenues. Specifically, this statute:

> …allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset. [5]

Thus, MISO Schedule 26 revenues must offset (reduce) costs charged to retail ratepayers in utilities' transmission riders.

V. CERTIFICATE OF NEED COST ESTIMATES AND COST CAPS

Q. Is it important for the Commission to hold utilities accountable for their Certificate of Need (CN) cost estimates?

A. Yes, ratepayers' interests must be protected. Companies' cost estimates are used extensively in CN and other regulatory proceedings and provide a strong basis for the Commission to hold utilities accountable to the costs they represent for facilities, particularly since as CNs consider alternatives to proposed projects. In its role to ensure that rates are reasonable, the Commission has generally not allowed approval of

[5] *Id.*

projects in such proceedings to constitute a "blank check" for cost recovery in riders when actual costs are greater than the estimated costs the utilities represented in regulatory approval proceedings. For example, as discussed further below, the Commission typically requires utilities to demonstrate that it is reasonable to allow recovery of any such cost increases prior to charging the costs to ratepayers.

The Department fully supports the Commission's use of such mechanisms. Absent cost recovery caps tied to the evidentiary record in which the project was proposed and approved, utilities have little incentive to expend the effort needed to accurately report project costs in regulatory proceedings, nor to ensure that the actual costs are contained and are as reasonable as possible.

Q. How will the costs of the proposed Project likely be charged to ratepayers in Minnesota?

A. I confine my answer to the rates to be charged by utilities subject to the Commission's rate making authority (rate-regulated utilities).[6] The most likely way that the costs and offsetting revenues would be charged to Minnesota ratepayers is through transmission riders. Transmission riders give rate-regulated utilities the extraordinary ability to charge their ratepayers for costs of facilities prior to the projects being placed into service, that is, used and useful, and before the utilities' next rate case. Absent the ability to recover costs through a rider, recovery would not be allowed until the first rate

[6] I do not include ratepayers of municipal or cooperative utilities in my answer.

case after the project goes into service (or is projected to go into service during the forecasted test year).

Q. What are some of the ways that the Commission has ensured that ratepayers' interests are protected when riders are used?

A. In exchange for the advanced recovery that the legislature has permitted utilities through transmission riders, ratepayers need reasonable assurance the costs utilities charge to ratepayers through these riders are reasonable. Simple, but important ways that the Commission has used to ensure that costs reflected in rates are reasonable are: 1) to require utilities to wait until the first rate case after a project is in service to recover any cost overruns and 2) to require utilities to justify fully the reasonableness of recovering any of the cost overruns of projects. This approach has helped ensure that ratepayers are reasonably protected and that utilities are held accountable for ensuring that reasonable projects are developed and implemented.

Q. Please explain more specifically how the Commission holds Minnesota rate-regulated utilities accountable for their transmission CN cost estimates.

A. The Commission holds utilities subject to their jurisdiction accountable for their transmission CN cost estimates by capping the amount of costs approved for recovery from ratepayers in their transmission riders. The cap is set at the amount of costs the utility represented for the project in the proceeding where the project was approved. Utilities are allowed inflation from the year in which costs are approved to the in-service date of the facility. In addition, utilities are allowed to request recovery of cost overruns in subsequent rate cases in the same way that they always have been able to do, but utilities have the clear burden to demonstrate why it is reasonable to charge ratepayers for any such cost overruns.

Q. Do you have examples of such decisions to limit cost recovery of cost overruns in riders?

A. Yes, there are many. For example, in Xcel Energy's TCR Rider filing in Docket No. E002/M-09-1048, the Commission decided the following regarding Xcel's recovery of transmission project costs on a going-forward basis in its April 27, 2010 Order:

> …the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

The Commission applied this same approach to Otter Tail Power, in Otter Tail Power's 2013 Transmission Cost Recovery Rider (Docket No. E017/M-13-103). The Commission stated in its March 10, 2014 Order that:

> Accordingly, the Commission continues to believe that project costs included in the TCR rider should be capped at certificate of need levels, and concurs with the Department that the appropriate cap for the Bemidji project is $74 million. The TCR rider mechanism gives Otter Tail the extraordinary ability to charge its ratepayers for facilities prior to the ordinary timing (the first rate case after the project goes into service) and without undergoing the full

> scrutiny of a rate case. Holding the Company to its initial estimate is an important tool to enforce fiscal discipline.
>
> Further, imposition of a cap protects the integrity of the certificate of need process, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. And, capping costs at the certificate of need levels is consistent with the Commission's actions in similar cases involving other utilities' riders.
>
> The Company is recovering the cost of these transmission facilities through a rider, a unique regulatory tool essentially designed to enable utilities to begin recovering the prudent and reasonable costs of critically needed capital investments between rate cases. The rate case remains the primary vehicle for determining prudence and reasonableness.
>
> In the absence of a rate case, the best available proxy for determining prudence and reasonableness is the cost determination made on the record of a certificate of need or cost recovery eligibility proceeding. Here, the relevant proceeding is a certificate of need case. Otter Tail should continue recovering the costs it sponsored in its certificate of need case unless and until it demonstrates in a rate case that higher costs are prudent and reasonable. [footnotes omitted]

Q. Does ITCM have the ability to collect costs from ratepayers through a transmission rider under Minnesota statutes?

A. Not that I am aware of. ITCM is a wholesale transmission company with rates set by the Federal Energy Regulatory Commission (FERC) and does not directly deliver electricity to retail customers in Minnesota. As such, ITCM does not have a transmission rider in Minnesota, but does charge rates set by FERC. Therefore, the Minnesota Commission does not have the same ability to hold ITCM directly accountable for its CN cost estimates for purposes of protecting retail ratepayers as it does with traditional Minnesota rate-regulated utilities.[7]

Q. Has the Commission's use of cost caps, as described above, applied to the costs used to determine the FERC-approved annual revenue requirements that are allocated/charged to utilities under MISO Schedule 26?

A. No. These cost caps apply to the costs of the Project that are used in calculating the Minnesota annual revenue requirements associated with the Project at the retail level. These caps do not apply to the costs used to determine FERC-approved (wholesale) annual revenue requirements that are allocated/charged to utilities under MISO Schedule 26, and eventually recovered from ratepayers in transmission riders or other rate mechanisms.

Q. Does MISO use cost caps to hold utilities accountable to the cost estimates approved by MISO?

A. No. Instead, if a project's costs exceed its estimate by more than 25 percent, MISO may conduct a variance analysis. The Applicants stated the following in their Petition regarding MISO's variance analysis process:

> Applicants are required to provide regular updates to MISO regarding the cost of the Project. Under Attachment FF of the MISO Tariff, if the cost of this Project exceeds or is projected to exceed 25 percent or more of the Project's

[7] The Commission does, however, have authority over ITCM in accordance with the approvals granted in Docket No. E001/PA-07-540 (*In re Joint Petition for Approval of the Transfer of Transmission Assets of Interstate Power and Light Company and ITC Midwest LLC)*.

> baseline cost estimate, MISO is required to initiate a new process called a “variance analysis.” A variance analysis for a project may also be triggered by a schedule delay or inability to complete project construction. A copy of the relevant sections of the MISO Tariff is attached as Exhibit___(AWS-1), Schedule 7.
>
> ….
>
> The Project’s baseline cost estimate is $108 million (2016$). Cost estimates for routes currently under consideration in the Route Permit process range from $104.8 million to $160.7 million. The Applicants will update the Project’s cost estimate provided to MISO after a route is determined by the Commission. Assuming that the current cost estimates do not change, any final route with a cost estimate of $135 million (2016$) or greater would trigger a MISO variance analysis once Applicants submit a cost update to MISO.

Applicants Ex.___ at 35-36 (Siebenaler Direct).

Q. Has MISO ever used this variance analysis process before?

A. No. The Applicants stated that:

> To date, MISO has not used this process before, but the general procedures for a variance analysis are set forth in the MISO Tariff. After a variance analysis has been triggered, MISO will notify the transmission owner – here, the Applicants. The Applicants would then discuss with MISO whether a variance event exists and what outcome the Applicants believe is appropriate, along with supporting facts and documentation. Based on this information, MISO may continue the variance analysis process or terminate it. If MISO continues the variance analysis process, MISO will further investigate the variance event and the surrounding facts. MISO will determine an appropriate outcome based on an examination of several factors including the cause or reason for the variance, the degree of fault of the transmission owner for the increased costs, impacts to the MISO Transmission System, and a comparison of the costs of different outcomes. After this evaluation, MISO can decide to: (1) take no action; (2) institute a mitigation plan to alleviate grounds for a variance; or (3) cancel the project.

Applicants Ex.___ at 36-37 (Siebenaler Direct).

Q. What do you summarize from the above?

A. Based on the above, I conclude that, if a project's costs exceed its estimate by more than 25 percent, MISO may conduct a variance analysis. Under such a scenario, MISO has the authority to: 1) take no action; 2) institute a mitigation plan to alleviate the grounds for a variance; or 3) cancel the project.

Q. Do you have any concerns with MISO's variance analysis process?

A. Yes. As the Applicants admit, MISO's process has never been used before. As a result, it is unclear to what extent MISO would require utilities to institute a mitigation plan if costs exceed estimates by more than 25 percent. In addition, it is unclear to what extent MISO would actually cancel a transmission project, especially if the project was already under construction and had incurred significant costs. Finally, it is unclear whether MISO would ever disallow recovery of cost overruns. Minnesota operates under the regulatory approach that, just because a utility incurs a cost, that fact isn't sufficient to justify cost recovery from ratepayers; utilities still must show that it is reasonable to recover the costs from ratepayers. It is unclear whether MISO would ever not allow a transmission owner to recover costs, even the amounts greater than a 25 percent variance.

Q. What do you recommend?

A. Given that MISO's variance analysis process is new and untested, I recommend that the Commission protect ratepayers' interest in this proceeding by taking the following steps. Once the Commission determines the costs of the proposed Project based on its decisions regarding route alternatives, the Commission should hold Xcel accountable by: 1) requiring Xcel to wait until the first rate case after the Project is in service to recover any cost overruns for Minnesota ratepayers and 2) requiring Xcel to justify fully the reasonableness of recovering any cost overruns of the Project from Minnesota ratepayers.

Q. Does this conclude your Direct Testimony?

A. Yes.

Previous Testimony of Mark A. Johnson

- Interstate Power and Light Company's *Joint Petition for Approval of Transfer of Transmission Assets to ITC Midwest LLC* (Docket No. E001/PA-07-540),
- Otter Tail Power Company's *Application for Authority to Increase Electric Rates in Minnesota* (Docket No. E017/GR-07-1178),
- Minnesota Power Company's *Application for Authority to Increase Electric Rates in Minnesota* (Docket No. E015/GR-08-415),
- Minnesota Energy Resources Corporation's *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G007,011/GR-08-835),
- CenterPoint Energy Resources Corporation, d/b/a CenterPoint Energy Minnesota Gas' *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G008/GR-08-1075),
- Northern States Power Company's *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G002/GR-09-1153),
- Interstate Power and Light Company's *Application for Authority to Increase Electric Rates in Minnesota* (Docket No. E001/GR-10-276),
- Minnesota Energy Resources Corporation's *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G007,011/GR-10-977),
- Interstate Power and Light Company's *Petition for Approval of Eligibility for Investment in Whispering Willow-East, Renewable Energy Recovery Adjustment, and 2010 Rate* (Docket No. E001/M-10-312),

- CenterPoint Energy Resources Corporation, d/b/a CenterPoint Energy Minnesota Gas' *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G008/GR-13-316),
- ITC Midwest LLC's *Application for a Certificate of Need for the Minnesota-Iowa 345 KV Transmission Line in Jackson, Martin, and Faribault Counties, Minnesota* (Docket No. ET6675/CN-12-1053),
- Minnesota Power's *Application for a Certificate of Need for the Great Northern Transmission Line Project* (Docket No. E015/CN-12-1163).
- CenterPoint Energy Resources Corporation, d/b/a CenterPoint Energy Minnesota Gas' *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G008/GR-15-424),
- Great Plains Natural Gas Company's, a Division of MDU Resources Group, *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G004/GR-15-879),
- Otter Tail Power Company's *Application for Authority to Increase Electric Rates in Minnesota* (Docket No. E017/GR-15-1033), and
- CenterPoint Energy Resources Corporation, d/b/a CenterPoint Energy Minnesota Gas' *Application for Authority to Increase Natural Gas Rates in Minnesota* (Docket No. G008/GR-15-424).