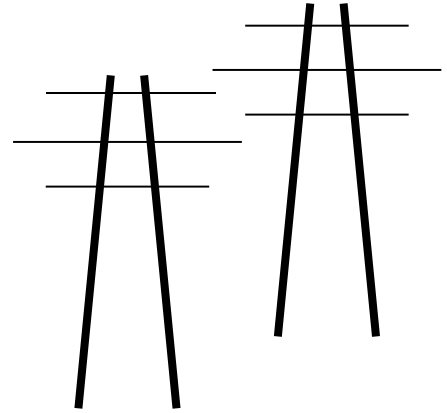


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March 28, 2025

Will Seuffert
Executive Secretary
Public Utilities Commission
121 – 7th Place East, #350
St. Paul, MN 55101

eFiled and email: consumer.puc@state.mn.us

RE: “NEED” Initial Comment
The Prehn Family & NoCapX 2020
Mankato-Mississippi Transmission Line f/k/a Wilmarth-N Rochester-Tremval
PUC Certificate of Need Docket CN-22-532

Dear Mr. Seuffert:

Thank you for the opportunity to file this Comment, made on behalf of the Prehn Family and NoCapX 2020. The Prehn Family has been a participant in utility issues for over 60 years, beginning with the licensing of the then Minnegasco gas dome in the 1960s which was taken up to the Minnesota Supreme Court; to stopping Minnegasco’s pollution of local fields by obtaining an EAW and construction of a water treatment system; to stopping the proposed Simon natural gas plant next to the Minnegasco pumping station along Hwy. 13; and now this transmission project through southern Minnesota.

I. INITIAL NEED COMMENTS

The record must reflect that this project initially proposed a route to run right over the gas dome, without prior notification to CenterPoint, and it was the Prehns who notified CenterPoint of this route proposal on April 25, 2024, and Xcel did not meet with CenterPoint until May 1, 2024,¹ and subsequently withdrew the route over the gas dome:

¹ [20245-206448-02](#)

Segment 1 Alternative 1L

In Segment 1 of the project, the applicant identified several routing alternatives (referred to as 1A through 1M), including 1L. The applicant has had additional discussions with CenterPoint Energy regarding existing infrastructure and future planned expansions of infrastructure as it relates to Segment 1 Alternative 1L. The proposed 345 KV transmission line would require setbacks from existing gas wells to allow for CenterPoint Energy to access the gas wells with large operational and maintenance equipment, and additional setbacks would be necessary to allow for planned equipment additions and expansion of the CenterPoint Energy Waterville Gas Storage Facility. The applicant has determined that Segment 1 Alternative 1L is no longer a feasible route alternative due to the necessary setbacks from CenterPoint Energy's existing and planned facilities.¹² The applicant requested that Segment Alternative 1L be removed from consideration as a routing alternative for the project.¹³ Segment 1 Alternative 1L will not be analyzed in the EIS.

EERA Scoping Decision, p. 4 of 8, November 16, 2024. But for the Prehn's interests and actions, would Segment 1 Alternative 1L over the gas dome have been even noticed, much less eliminated?

Similarly, NoCapX 2020 has intervened in multiple transmission dockets since 2006, pushing 20 years, and the issues remain much the same – so much so that utility forecasts from the CapX 2020 Certificate of Need proceeding² should be considered, particularly the “need” forecasts, as discussed below.

Bottom line: Claims of transmission need is misinformation at best. The issue in transmission is that transmission is not where it is wanted. There's sufficient generation, and that generation has been sited away from load where there is not sufficient transmission to interconnect, and sited where projects are waiting years and years to interconnect. The siting of all this generation far from transmission, far from load, and the following claim that transmission is “needed,” falls on the applicants and on the Public Utilities Commission for permitting these projects. This is a systemic problem. It is unreasonable to require ratepayers and landowners to pay for this transmission, and doubly unfair when the proposed transmission is not to serve Minnesotans, but to enable MISO's marketing plan.

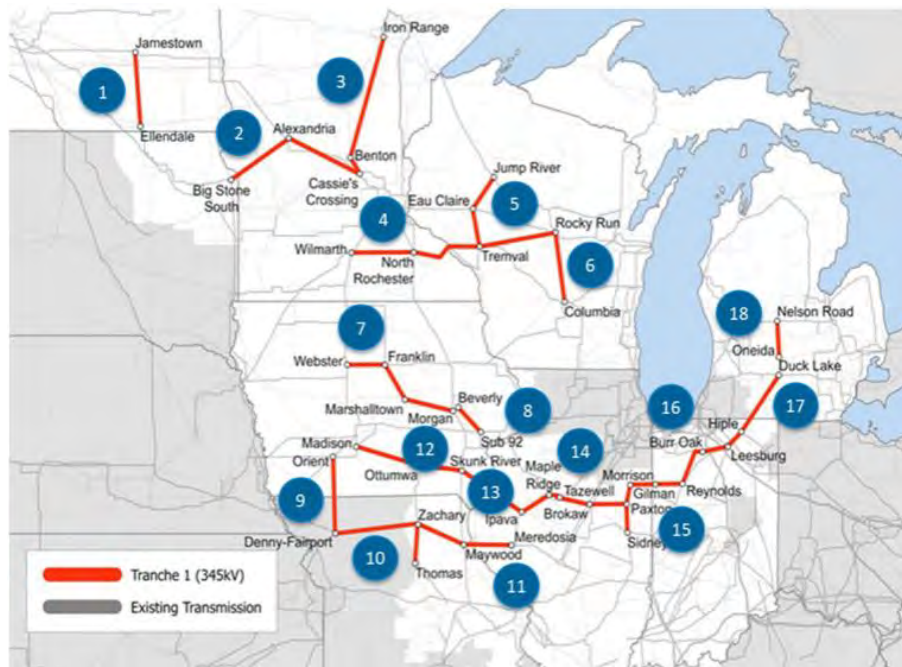
For years, decades really, this writer has been representing intervenors raising the essential truth that need is not a matter of utility and industry desires; that it is the distribution system that needs beefing up and that utilities are proffering transmission “solutions” to distribution deficiencies; and more recently, that MISO “approval” is not a demonstration of need – MISO is a marketing entity, and “benefits” of transmission it proposes are benefits to MISO members.³ Most importantly in terms of this and other Certificate of Need dockets, the Commission abdicates its responsibility to ratepayers and the public when it accepts a MISO approval as need, rather than give the project a robust Minnesota oriented independent review, and instead permits billions in utility marketing desire and subsequent transmission costs that are foisted on ratepayers and landowners.

This “North Mankato – North Rochester – Tremval” project does not exist in a vacuum. As

² PUC Docket CN-06-1115.

³ See e.g., Attachment A, Testimony of George C. Loehr in the PATH docket, addressing the issues present in this and all other utilities' MISO Tranche 1 and 2 transmission applications.

declared in the application, it is project 4 of MISO \$10 billion Tranche 1:⁴ And although the project is a part of the MISO Tranche 1, the Minnesota Public Utilities Commission is MINNESOTA'S regulator and must address the "need," the benefits and impacts to Minnesota.



ID	DESCRIPTION	EXPECTED ISD	EST COST (\$2022M)
1	Jamestown - Ellendale	12/31/2028	\$439
2	Big Stone South - Alexandria - Cassie's Crossing	6/1/2030	\$574
3	Iron Range - Benton County - Cassie's Crossing	6/1/2030	\$970
4	Wilmarth - North Rochester - Tremval	6/1/2028	\$689
5	Tremval - Eau Claire - Jump River	6/1/2028	\$505
6	Tremval - Rocky Run - Columbia	6/1/2029	\$1,050
7	Webster - Franklin - Marshalltown - Morgan Valley	12/31/2028	\$755
8	Beverly - Sub 92	12/31/2028	\$231
9	Orient - Denny - Fairport	6/1/2030	\$390
10	Denny - Zachary - Thomas Hill - Maywood	6/1/2030	\$769
11	Maywood - Meredosia	6/1/2028	\$301
12	Madison - Ottumwa - Skunk River	6/1/2029	\$673
13	Skunk River - Ipava	12/31/2029	\$594
14	Ipava - Maple Ridge - Tazewell - Brokaw - Paxton East	6/1/2028	\$572
15	Sidney - Paxton East - Gilman South - Morrison Ditch	6/1/2029	\$454
16	Morrison Ditch - Reynolds - Burr Oak - Leesburg - Hiple	6/1/2029	\$261
17	Hiple - Duck Lake	6/1/2030	\$696
18	Oneida - Nelson Rd.	12/29/2029	\$403
TOTAL PROJECT PORTFOLIO COST			\$10,324

⁴ MTEP21 Addendum-LRTP Tranche 1 Report with Executive Summary, p. 2
<https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf>

A. THE COMMISSION TOO FREELY AUTHORIZES “EXEMPTIONS” FROM PROVISION OF INFORMATION CRUCIAL TO A NEED DETERMINATION

An overarching concern regarding Certificate of Need dockets is that applicants are routinely exempted from many of the application requirements for a Certificate of Need. As Xcel noted in its Exemption Request:

The Commission has authority to grant exemptions from the requirements of Minnesota Rules Chapter 7849 pursuant to Minn. Rule 7849.0200, subp. 6.

Xcel Exemption Request, p. 4⁵. Xcel requested the following Exemptions:

Minnesota Rule	Scope of Exemption
Minn. Rule 7849.0260, subps. A(3) and C(6) (Losses)	Request exemption from providing line-specific loss information. Xcel Energy proposes to provide substitute data in the form of overall system losses.
Minn. Rule 7849.0270, subps. (1) through (6) (Forecasting)	Request exemption from providing specific forecasting and capacity information. Xcel Energy proposes to provide substitute forecast information used in analyzing the need for the Project.
Minn. Rule 7849.0270, subp. 2(E) (Annual Revenue Requirements)	Request exemption from providing annual revenue requirements for the Project. Xcel Energy proposes to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.
Minn. Rule 7849.0280, subps. (B) through (I) (System Capacity)	Request full exemption from providing a discussion of the ability of the existing system to meet the forecasted demand for electrical energy identified in response to Minn. Rule 7849.0270.
Minn. Rule 7849.0290 (Conservation)	Request exemption from discussing conservation programs and their effect on the forecast information required by Minn. Rule 7849.0270. Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.
Minn. Rule 7849.0300 (Consequences of Delay); Minn. Rule 7849.0340 (No Facility Alternative)	Request to be exempt from providing analysis using three confidence levels. Xcel Energy proposes to provide substitute data regarding potential impacts caused by delay or by not building the Project.

Id., p. 5-6.

Just because something is authorized, just because it has been done that way before, does not mean that it should be done! More likely, it’s an indication that scrutiny is needed.

Xcel leads its Exemption Request using MISO review and approval as its basis for the request:

The Project was studied, reviewed, and approved as part of the Long Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent

⁵ [202310-199659-02](#) 22-532 (CN) XCEL ENERGY Initial Filing EXEMPTION REQUEST AND ATTACHMENT A 10/17/2023

Independent System Operator, Inc.’s (MISO Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report. The Joint Utilities filed a notice of intent to construct, own, and maintain the Project with the Commission on October 10, 2022.

The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as a portion of LRTP4 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio. The transmission system in southern Minnesota is the nexus between significant renewable resources in Minnesota and the Dakotas and the regional load center of the Twin Cities and load centers to the east in Wisconsin. The amount of renewable energy generation on the electric system is increasing as aging traditional generation resources retire and are replaced with renewable resources. This Project will provide additional transmission capacity that is needed to reliably deliver this renewable energy to customers. This Project will relieve overloads on existing transmission facilities and will also reduce congestion on the transmission system resulting in lower energy costs.

Id., p. 3 (footnotes omitted).

Xcel claims that “[b]ased on the standard set forth in this rule, the Commission may grant exemptions when the data requirements: (1) are unnecessary to determine need in a specific case; or (2) can be satisfied by submitting documents other than those required by the rules,” but check the chart above for what it is they are using:

- Xcel Energy proposes to provide substitute data in the form of overall system losses.
- Xcel Energy proposes to provide substitute forecast information used in analyzing the need for the Project.
- Xcel Energy proposes to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.
- Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.
- Xcel Energy proposes to provide substitute data regarding potential impacts caused by delay or by not building the Project.

At this time, the Commission and other detractors will say that this is not the time for addressing Exemptions, that it’s water under the bridge. However, as a part of its need review, it’s the job of Commission, and Commerce DER, to determine whether what is actually produced by Xcel is sufficient, whether the information requested is in fact unnecessary to determine need in a

specific case; or whether the information required in the rule can be satisfied by submitting documents other than those required by the rule. A part of that review should be careful examination of those matters targeted for exemption to determine whether they are material matters for consideration.

While the Commission has exempted Xcel from providing this data for this project, it is exemptions only to its rules for **application content**. Xcel is not exempted from providing that data in the process of review of its application, if consideration of that data is warranted. A cursory look says these exempted categories deserve a closer look. For example:

1. Xcel Energy proposes to provide substitute data in the form of overall system losses.

Xcel Energy's first item on its list for exemption is line loss. That's a presumed indicator of the level of importance to Xcel. System-wide losses have become the standard since the SW Minnesota 345kV transmission docket, 01-1958, which turned on line losses, hence that information is no longer disclosed.

The Commission knows that transmission entails significant losses, as disclosed in the MN Energy CON transmission line docket (CN-22-131 and TL-22-132). In that docket, Xcel admitted that that of 2,200 MW generation into the line, it would deliver only "approximately 1,996 MW to the Sherco Substation." The Commission clearly stated this in its Order, that the Commission presumes "approximately" 204 MW line loss, if 160 miles, 12.75%, and if 180 miles, 11.33% is lost⁶. At long last the Commission is recognizing, in an Order, the inherent inefficiencies of transmission over distance. Going forward, in its need determination, such as this Mankato-Mississippi transmission docket, the Commission must require disclosure of line loss for this project over the distance from Mankato to the Mississippi River (if considering just Minnesota), and weighing in its need determination the impacts of line loss and the amount of additional generation, reactive power or other voltage stabilizing methods, necessary to make up for that line loss. Line loss is an inherent inefficiency of transmission, it's the laws of physics, and despite the grand rush and effort to permit more transmission, there is no excuse to ignore line loss.

But that's exactly what Commerce DER recommended, that Xcel not even disclose the specific "Mankato-Mississippi" line loss, based on Xcel's statement and prior exemptions granted by the Commission, with no support, relying only on Xcel's statement. This DER recommendation was accepted by the Commission and Xcel was exempted from providing line loss attributable to this specific project, as was required for the MN Energy CON line. The Commission had actual

⁶ In the Commission's Order of August 10, 2023 (CN-22-131; TL-22-132), the commission admitted, after interconnection of 2,200 MW, line losses of approximately 204MW, to result in 1,996 delivered to the Sherco substation, roughly a MW per mile, as did Xcel in describing the specs of the line -- from the application:

The two lines would be located on the same set of structures (i.e., a double-circuited transmission line) and would connect at least 2,200 megawatts (MW) of generation and deliver (after losses) approximately 1,996 MW to the Sherco Substation.

knowledge of the high percentage of line loss on that line, and this Mankato – Mississippi is even longer. Though Xcel was exempted from disclosing line loss in its application, it has not been exempted from disclosure of line loss information in the Certificate of Need proceeding.

What was disclosed in the application? An example of expected line loss is found in “LRZ1” without and with LTRP4, the Mankato-Mississippi project plus the Wisconsin portion (mindful that MVAR losses must be compensated for in some manner, i.e., injection of reactive power and/or series compensation, etc.):

Table 4-15
Estimated Line Losses

MTEP22 2027 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 4	Delta	Tranche 1 without LRTP 4	Tranche 1	Delta
MW Losses	1031.8	999.8	32.0	883.4	849.4	34.0
MVAR Losses	9628.6	9513.5	115.1	8882.3	8770.1	112.2

Future 1 Year 20 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 4	Delta	Tranche 1 without LRTP 4	Tranche 1	Delta
MW Losses	1220.5	1159.6	60.9	1071.0	1027.0	44.0
MVAR Losses	10834.4	10490.2	344.2	9941.9	9782.6	159.3

Table 4-16
Average Line Losses

	Average SH Losses
MW Losses	42.73
MVAR Losses	182.70

Xcel Application, p. 82.

First, look at those charts – looking strictly at MW losses, is consideration of line loss make any sense when the plan for this project is to spend \$457.4 million dollars (MISO) to \$577.2 million dollars (Xcel) for a claimed loss savings of 32-34, 44, or 60.9 MW, averaging 42.73MW? That’s over \$10 million per megawatt! Is that loss savings any justification for this project? Then take a look at the full losses admitted – the LRZ1 MW and MVAR losses are roughly the equivalent of the 2 reactor Prairie Island Nuclear Generating Plant’s capacity. In addition, what will this need for support cost in terms of reactive power, series compensation, and the generation needed to make up for these line losses? Note that only LRTP4 is in the chart, and no “Mankato-Mississippi” transmission project, so we have no idea losses attributable to this project.

The cost of line loss and reactive power specifically related to this line must be considered and weighed in determination of need for this Mankato-Mississippi portion of this project.

2. Xcel Energy proposes to provide substitute forecast information used in analyzing the need for the Project.

What forecast information does Xcel plan to use? A simple search of the application for the word “forecast” shows that Xcel is relying on MISO. From the Table of Contents:

- **4.2.4 MISO Futures Development and Transmission Planning**
- **4.2.5 LRTP Tranche 1 Portfolio**
- **4.2.6 MISO’s Summary of Need for the Project**

See Xcel Application, pps. 53-62. Then the application goes on to state “Xcel’s analysis” of forecast:

First, Xcel Energy conducted an analysis based on the most current MISO transmission system model (MTEP22) assuming no additional generation is added to the system. ...

Second, Xcel Energy conducted an analysis based on the MTEP21 Future 1 (at year 20) to show improvements to system reliability related to the Project in the future when additional generation is online.

Xcel Application, p. 67. Xcel’s “analysis” focused on MISO territory of Zones 1 and 2:

**Map 4-4
MISO Local Resource Zones**



Id., p. 69.

When a Minnesota utility bases its Certificate of Need case before the Minnesota Public Utilities Commission on MISO forecasts, MISO futures and MISO regions 1 and 2, and the “Xcel analysis” is also fully based on MISO, it’s clear the driver is MISO, a marketing entity, which includes Xcel. It’s also shown in Xcel’s own application that this is not about Minnesota. What’s in it for Minnesota?

The estimation of “benefits” and drafting of the entire plan are MISO’s doing, logically utility driven. Thus far, the benefit is the MISO members (see below, MISO LRPG Tranche 1 Benefits Chart, Figure 4.4). There’s no demonstrated benefit to Minnesota, its ratepayers, and the landowners whose land will be taken for this project, yet isn’t the Commission’s responsibility protection of Minnesota, its ratepayers, and landowners through regulation of utilities?

a. Xcel's demand is NOT increasing

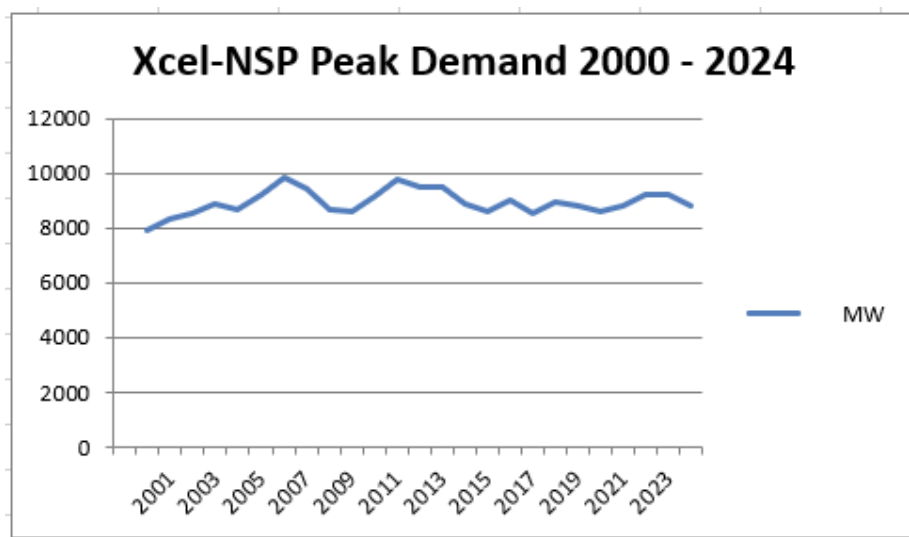
On the other hand, Xcel's reliance on MISO makes sense, because where "need" is concerned, Xcel has a "need" problem because Xcel's demand has not yet met the 2006 peak of 9,859MW, calling "need" into question. From Xcel Energy's SEC 10-K filing⁷, the peak of 2024:

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

Utility Subsidiary	2024		2023	
	MW	Date	MW	Date
NSP System	8,822	Aug. 26	9,231	Aug. 23
PSCo	7,084	Aug. 1	6,909	July 24
SPS	4,437	Aug. 19	4,372	Aug. 17

This is important because at 8,822 MW, Xcel's peak demand is down 409 MW from last year. More importantly, at 8,822 MW, Xcel's peak demand has not reached the all-time high peak demand of 9,859 MW in 2006! Why is this important? Xcel is now crying that "demand will go UP, UP, UP!" as it falsely claimed in the CapX 2005. What does Peak Demand look like over the last 25 years according to Xcel Energy's SEC 10-K filings? Here are the numbers:



From Xcel's 10-K SEC filings:

2000	7,936
2001	8,344
2002	8,529
2003	8,868
2004	8,665

⁷ Xcel's 2024 SEC 10-K: https://legalelectric.org/f/2025/02/Xcel-Peak-Demand-2024_0000072903-25-000029-e2853810-9fe1-4df5-89d1-e14f11e5c841.pdf

2005	9,212
2006	9,859
2007	9,477
2008	8,657
2009	8,615
2010	9,131
2011	9,792
2012	9,475
2013	9,524
2014	8,848
2015	8,621
2016	9,002
2017	8,546
2018	8,927
2019	8,774
2020	8,571
2021	8,857
2022	9,245
2023	9,231
2024	8,822

Xcel has met its need each year, and peak demand has been below the 2006 high, **in 2024, 1,000MW lower**, despite forecasted CapX 2020 “forecast” of 2.49% annual growth.⁸

b. System line losses in MW and MVAR are greater than Xcel’s peak demand

In this transmission application, Xcel includes tables regarding line loss. Xcel’s 2006 peak demand of 9,859MW... that 9,000MW number seems familiar... oh, right, it’s that chart of line losses, and MVAR losses of over 9,000MW in the system as it is, it’s even more than Xcel’s peak demand!

Table 4-15
Estimated Line Losses

MTEP22 2027 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 4	Delta	Tranche 1 without LRTP 4	Tranche 1	Delta
MW Losses	1031.8	999.8	32.0	883.4	849.4	34.0
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Future 1 Year 20 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 4	Delta	Tranche 1 without LRTP 4	Tranche 1	Delta
MW Losses	1220.5	1159.6	60.9	1071.0	1027.0	44.0
MVAR Losses	10834.4	10490.2	344.2	9941.9	9782.6	159.3

One of the tropes of transmission build-out is that more transmission, and these high capacity transmission lines, would lower line loss! Apparently not!

⁸ See CapX 2020 Technical Update, p. 5 (2005), Attachment E to CapX 2020 Certificate of Need Application. <https://nocapx2020.info/wp-content/uploads/2012/02/capxvisionstudy20120214-515026913743.pdf>

c. Xcel's forecasts are historically grossly overstated

There's another reason Xcel would rely on MISO and wouldn't want to make its own case for need. Not all of us have forgotten Xcel's very gross overstatement of need in the CapX 2020 need docket, with the preposterous forecast claim of a 2.49% annual increase! Xcel has a habit of overestimating demand, as noted by the Office of the Attorney General in a recent docket.⁹ From the PUC's 2021 IRP Order, DER-Commerce also recognizes that overstatement of demand:

The Department presented its own proposal that differed from Xcel's in many respects. In particular, the Department argued that over time Xcel's analysis systematically overestimates demand and underestimates capital costs, leading the company to propose needlessly expansive growth.

Order, p. 11, PUC Docket RP-19-368.

As we saw in the CapX 2020 need docket (CN-06-1115), Xcel "systematically overestimates demand and underestimates costs." In 2006, if you recall, or if you'll do homework, as many of you were not around then, Xcel was saying, as the basis for its CapX 2020 transmission expansion, that demand would go UP, UP, UP at an astronomical rate of 2.49% ANNUALLY!.

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

Table 1 – CapX 2020 Anticipated Area Growth

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

From the CapX 2020 Vision Study, p. 5¹⁰:

Really. What a load! This forecast was not credible then, and now with so much verifiable data

⁹ Attachment C, OAG-RUD, Comments p. 16, Xcel IRP Docket 24-67 [202412-212710-03](#) (Dec. 4, 2024), citing 2022 IRP Order at 11; Docket No. E-002/RP-19-368, Supplemental Comments of the Department of Commerce at 9 (Oct. 15, 2021).

¹⁰ <https://nocapx2020.info/wp-content/uploads/2012/02/capxvisionstudy20120214-515026913743.pdf>

from Xcel's own SEC filings, there's no excuse. Yet buying into that notion, the Commission granted a Certificate of Need¹¹ for the CapX 2020 transmission projects. Xcel and its "environmental" proponents claimed then and now that increased generation and transmission is "needed" for renewable energy, and Xcel states:

The amount of renewable energy generation on the electric system is increasing as aging traditional generation resources retire and are replaced with renewable resources. This Project will provide additional transmission capacity that is needed to reliably deliver this renewable energy to customers.

Exemption Request, p . 4. Xcel admits that there is increased renewable energy generation, and admits that "traditional generation resources retire and are replaced with renewable resources." "Replacement theory" doesn't work politically, and it makes even less sense in physics. For transmission, when you remove generation, that frees up transmission capacity. There's no logical need for more, and there certainly is no need for a MISO Tranche 1. The existing system handled the peak in 2006, and since that time massive amounts of transmission capacity have been added via CapX 2020 and MOSI's MVP projects, particularly in southern Minnesota with the SW MN 345kV transmission project (PUC 01-1958); CapX 2020's Brookings-Hampton and Hampton-La Crosse – Cardinal Sub (Madison); and ITC's MVP Projects 3, 4 and 5, across southern Minnesota, northern Iowa, and off towards Madison. Add to this transmission capacity the capacity resulting from closing of coal plants. With all this transmission capacity, what's the real issue? Name that gorilla in the room.

If transmission isn't where they "need" it (want it), if Xcel and renewable developers are siting new generation in the wrong places, if the Commission is permitting projects where there is not sufficient transmission capacity for the generation, this is a problem of Xcel's, the developers', and the Commission's creation. Why should, why would, the Minnesota Public Utilities Commission buy into this and make ratepayers and landowners take the hit?

3. Xcel Energy proposes to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.

By proposing to provide "general information regarding how the costs for LRTP projects are shared within the MISO footprint," Xcel is diverting from cost of this project to Minnesota, which logically includes Minnesota ratepayers and landowners.

Xcel has yet to disclose how this specific project's costs are apportioned in Minnesota, and will only discuss "how the costs for LRTP projects are shared within the MISO footprint." This raises that classic questions: Who benefits? Who pays?

Who pays? Look at MISO's Tranche 1 Schedule 26A.¹²

¹¹ PUC Docket CN-06-1115

¹²¹² [LRTP Tranche 1 Appendix A-4 Schedule 26A Indicative
https://cdn.misoenergy.org/LRTP%20Tranche%201%20Appendix%20A-4%20Schedule%2026A%20Indicative625788.xlsx](https://cdn.misoenergy.org/LRTP%20Tranche%201%20Appendix%20A-4%20Schedule%2026A%20Indicative625788.xlsx)

On the other hand, who benefits? The “who benefits” question is relatively easy to resolve – and the “who benefits” is a side of the need calculation that should be assessed. Check the MISO Tranche 1 page for the “business case.”¹³ The benefactors of MISO’s plans are to the MISO members:

Figure 4-4
LRTP Tranche 1 Economic Benefits⁴⁸

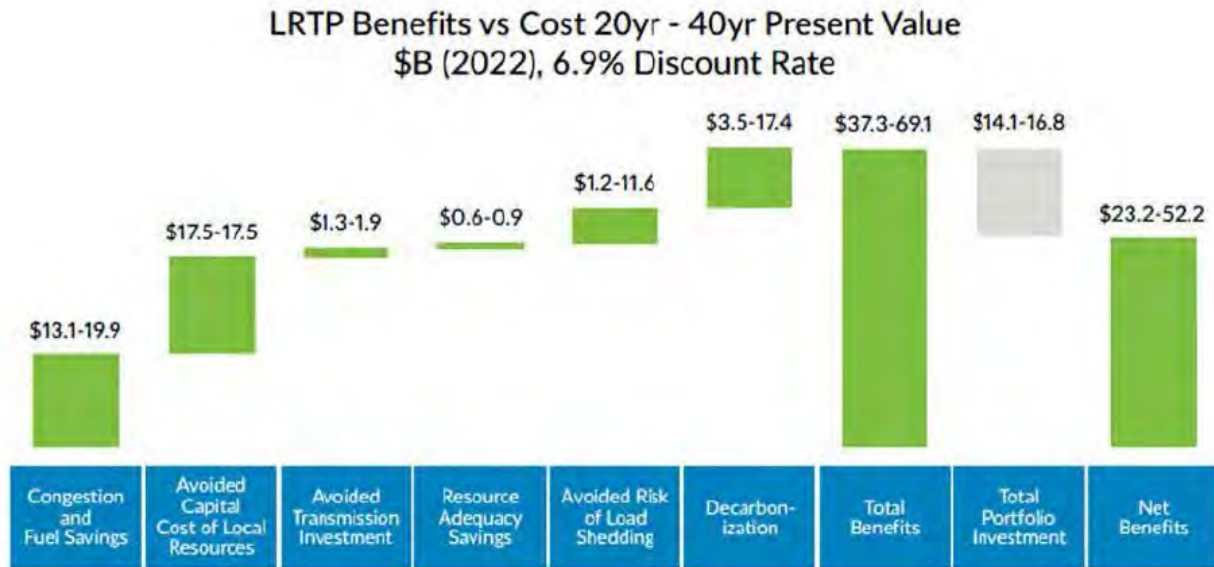


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

Who pays? That will be ratepayers via apportionment in various jurisdictions and landowners who lose their land to this project. Payment is not only for the infrastructure of the proposed transmission line, but also for the service that transmission line will provide.

For the entire MISO Tranche 1 “MISO projects that the MISO LRTP Tranche 1 Portfolio will provide \$23.2 billion to \$52.2 billion in net economic savings over the first 20 to 40 years (respectively) of the portfolio being inservice – a benefit to cost ratio range of 2.6 to 3.8.”¹⁴ Yet

¹³ [LRTP Tranche 1 Detailed Business Case](https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf)
[https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf](https://cdn.misoenergy.org/LRTP%20Tranche1%20Detailed%20Business%20Case%20Analysis625787.xlsx)
[LRTP Tranche 1 Detailed Business Case Analysis](https://cdn.misoenergy.org/LRTP%20Tranche1%20Detailed%20Business%20Case%20Analysis625787.xlsx)
<https://cdn.misoenergy.org/LRTP%20Tranche1%20Detailed%20Business%20Case%20Analysis625787.xlsx>

¹⁴ The footnote states, “The 2.6 to 3.8 benefit to cost ratio is for the entire MISO Midwest subregion. MISO projects that Minnesota and the surrounding region (“MISO Cost Allocation Zone 1”) will realize a 2.8 to 4.0 benefit to cost ratio – slightly better than the broader MISO Midwest subregion.” Note that the benefit cost is for the “entire MISO Midwest subregion,” and the more geographically restrictive phrase above narrows it vaguely to “Minnesota and the surrounding region,” with no boundaries, so it could meet anything.

look at, for example, the first three categories: Congestion and Fuel Savings, Avoided Capital Costs of Local Resources, and Avoided Transmission Investment. How many of those categories would be eliminated if generation was sited near load? Again, see Attachment A, Testimony of George C. Loehr. For MISO specific analysis of these “benefits” see Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics. MISO understandably finds the conclusions of this report objectionable – it points out the misinformation that serves as the basis for the MISO transmission build-outs, and the economic and reliability benefit of siting near load:

- It is important that this investment be economic –
 - ✓ Uneconomic investment will raise costs and undermine investment in resources, storage and other alternatives to transmission.
 - ✓ We have previously expressed concerns about the unrealistic nature of Future 2A growth assumptions.
 - ✓ MISO has chosen not to attempt manual optimization (evaluating alternative siting impacts on individual projects or to resolve overloads).
 - ✓ The benefits methodologies are likely to lead to substantially over-estimated benefits, which we describe in this presentation.
- MISO has proposed 9 classes of transmission benefits.
- Classes that are likely to be valid and reasonable, depending on the details:
 - ✓ Congestion and fuel costs savings
 - ✓ Reduced transmission outage costs
- Classes for which we have significant or fundamental concerns:
 - ✓ Avoided capacity costs
 - ✓ Decarbonization
 - ✓ Mitigation of reliability issues
- Classes that are may be overestimated depending on the methodology
 - ✓ Capacity savings from reduced losses
 - ✓ Energy savings from reduced losses
 - ✓ Avoided transmission investments
 - ✓ Reduced risks from extreme weather events

Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics.¹⁵

4. Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.

In Certificate of Need applications, the effect of conservation and energy efficiency are given

¹⁵ Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics
<https://cdn.misoenergy.org/20240529%20LRTP%20Workshop%20Item%2002%20IMM%20Presentation633033.pdf>

short shrift by the applicant and by the Commission. Here, Xcel Energy proposes to provide substitute information related its conservation programs in Minnesota. Xcel Energy will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.

In all analysis of conservation and energy efficiency, conservation and energy efficiency is least cost. Traditionally, conservation and energy efficiency are considered as “alternative” only where the conservation and energy efficiency” can replace, in toto, the claimed “need,” and the combining of “alternatives” is deemed not to meet “need.”

Before a need determination can be made, Xcel must demonstrate the possibilities that a combination of conservation and energy efficiency measures can produce, and proceed with a need claim on the balance, and only on the balance. See Minn. Stat. §216B.243, Subd. 3(7).

5. Xcel Energy proposes to provide substitute data regarding potential impacts caused by delay or by not building the Project.

The Exemption Request came before the Commission on the Consent Agenda, signed December 12, 2023.

1. Should the Commission grant the exemptions to the certificate of need application content requirements as requested by Xcel Energy in its filing on October 17, 2023?
2. Should the Commission approve Xcel Energy's Notice Plan Petition for a Certificate of Need for the Mankato - Mississippi 345 kV Transmission Project? (PUC: Panait; DOC: Miltich; Rakow)

The subsequent Order filed, dated December 12, 2023, addressed only approval of the Notice Plan, with nothing regarding the Exemption Request that had been on the Consent Agenda and approved, with a public Comment period, extended a week, ending on November 27, 2023. Xcel's proposed substitutions were approved with nominal, if any, consideration by the Commission, Commerce, and the public.

B. MISO IS NOT THE REGULATOR

Surprise – MISO IS NOT THE REGULATOR! The Commission and Department must be clear in its review that it is the regulator, not MISO, and assure that the Commission's review complies with Minnesota statutes and rules. Need more be said? I guess so, as the Commission gives great weight to MISO “approval.”

However, on October 23, 2024, there was a Notice for Comments in this docket that admits that it's all about MISO:

Topic(s) Open for Comment:

- Should the Commission grant the exemptions to the certificate of need application content requirements as requested by Xcel Energy in its filing on October 17, 2023?

Background: Xcel Energy intends to file an application for a certificate of need with the Minnesota Public Utilities Commission for the construction of a single-circuit 345 kV transmission line in southeast Minnesota, designated as the Mankato – Mississippi Transmission Line Project. This project is part of the Long-Range Transmission Planning studied and reviewed by the Midcontinent Independent System Operator (MISO) and approved in July 2022.

Commission October 23, 2024 Notice for Comments.

Review and analysis of this Certificate of Need application must comply with Minnesota Certificate of Need statutes and rules. Minn. Stat. §216B.243, Subd. 3(7); Minn. R. ch. 7849.

C. COMMISSION SUBSTANTIVE CONSIDERATION OF NEED GOES BEYOND ACCEPTANCE OF APPLICANT’S STATED PURPOSE AND CLAIMED NEED

In earlier meetings in this docket, and it was stated in the Scoping Notice, the presentation (p. 27) and several times orally that at issue and up for comment is:

Are there other ways to meet the stated need for the project, for example, a different size project or a different type of facility?

That statement means that the stated need/purpose as provided by an applicant is accepted and is the starting point for a need discussion. See Draft Scope, 1.0 “Purpose.” This means that the purpose is accepted and that questioning that stated need and purpose is off the table.

NO! Acceptance of the “stated” need and purpose is abdication of the Public Utilities Commission’s responsibility and mandate. **Size, type and timing of “need” is at issue** – that’s why there is a Certificate of Need process and criteria in law ([Minn. Stat. §216B.243, Subd. 3a \(1-12\)](#)). This is a Certificate of Need docket (CN-22-532). The applicant and/or MISO are not the arbiters of need.

A need determination is to be made by the Commission after the review of factors, above, and a decision that is supported by facts and the record. A “stated need” by the applicant and/or a desire of MISO is not sufficient.

D. NEED AND SYSTEM ALTERNATIVES

The need analysis and system alternatives must address use of other voltage and configurations of transmission lines. The analysis must also include other system alternatives such as conservation and energy efficiency, siting near load, electrical system alternatives analyzed separately from the market desires of Xcel and MISO.

According to Xcel’s application, page 162, the “System Peak Energy Demand” is 718 MVA. The project is designed for 3,585 MVA, Table 5-1. 3,585 MVA is roughly FIVE TIMES more

than Xcel's highest claim of "System Peak Energy Demand" of 718. If "System Peak Energy Demand" is 718 MVA, according to Table 5.1, a single circuit 230kV line would be sufficient! See Draft Scope, 1.0 Design. The Commission must address this discrepancy and clearly evaluate Xcel's case for a line with capacity FIVE times higher, 3,585 MVA, than the "System Peak Energy Demand" of 718 MVA.¹⁶

E. NEED IN A SYSTEM THAT'S "ALL CONNECTED" REQUIRES PUC CONSIDERATION OF EXISTING CAPX 2020, MVP 3, 4 & 5, AND MISO TRANCHE 1, AND SPECIFICALLY THE FOUR TRANSMISSION LINES PROPOSED IN SOUTHERN MINNESOTA LESSEN NEED FOR NEW TRANSMISSION

As testimony in the Arrowhead-Weston project declared 24 years ago regarding transmission, "it's all connected." This proposed Wilmarth-North Rochester-Tremval or Mankato, North Rochester, Mississippi Transmission Project (note, no transmission line ends in the Mississippi River) is not proposed in a vacuum. That it's all connected is a fundamental characteristic of "the grid." When considering "need," for a project, phased and connected actions must be considered.

This concept is important because, including this project, in addition to the recent transmission build-outs, there are FOUR transmission lines originating in southern Minnesota, and two of which go "against the current" of typical transmission power flows:

- Wilmarth-North Rochester-Tremval a/k/a Mankato-Mississippi (this docket)
- Brookings-Hampton 2nd circuit – CN-23-200 & TL-08-1474
- Big Stone-Alexandria-Big Oaks – CN-22-538 & TL-23-159/TL23-160
 - o Against the flow, SW to NE
- MN Energy CONnection – CN-22-131 & TL-22-132
 - o Against the flow, SW to NE

In light of all of these projects, and in light of existing transmission in southern Minnesota, is this project needed? The Public Utilities Commission must look to the big picture.

What's the big picture? Where is the "need" when considering the SW MN 345kV line (CN-01-1958) connecting into the MVP 3, 4 (TL-12-1337 and CN-12-1053), and the delayed but now fully permitted MVP 5, from SW Minnesota down into the top of Iowa and heading east into Wisconsin. Institutional memory, as MVP 3, 4 and 5's transmission in southern Minnesota and Iowa extending beyond are not adequately addressed in the Xcel application:



¹⁶ See again Attachment B, MISO IMM Comments on LRTP Tranche 2 Benefit Metrics
<https://cdn.misoenergy.org/20240529%20LRTP%20Workshop%20Item%2002%20IMM%20Presentation633033.pdf>

Consideration of these connected projects must also include consideration of the Public Utilities Commission's repeated actions of permitting projects where there is no interconnection option available. The Public Utilities Commission should not be permitting siting of generation based on wishful thinking and marketing plans. Those projects waiting for interconnection should be identified, and the Commission's actions declared void. If there is interconnection available, documented and at a cost outlined in the MISO DPP System Impact Study Reports, that cost should be properly allocated to the project developers and not Minnesota ratepayers.

F. LINE LOSSES HAVE IMPACT ON "NEED" FOR GENERATION AND ITS TRANSMISSION

Line losses have an impact on "need" for a project, because the longer the line, the higher the line loss, the more generation must be built to deliver a set amount of energy to its destination. The physics of long transmission lines is typically not considered, and must be. For example, as above in the "Exemptions" section, it's noted that the MN Energy CONnection transmission has declared an expected 200MW or more line loss, meaning that additional amount of generation must be built and paid for and land taken if the specific amount of energy is to be delivered, plus there's a reactive power requirement to stabilize the line, and also capital construction costs and transmission service cost that weighs against "need" for the project.

Typically, and improperly, the line loss for the project applied for is expressed as a percentage and/or megawatts across the entire MISO system or Eastern Interconnect. Line loss is an aspect of the project that should be reviewed separately for this project, terminal to terminal, for this particular project, and not hidden as a very small percentage or low MW of an undisclosed total energy across the system. Line loss is the amount of energy that would be dissipated by transmission over distance, and the amount and impact of the MW of additional generation to assure the requisite load gets to the other end of the line. The amount of increased generation necessary to make up for line loss will increase "need" for the project, so line loss must be compared between the project as applied for, and all alternatives presented, including the "no build" alternative.

G. ADDITIONAL TRANSMISSION NEEDED STARTING AT WILMARTH?

The Commission should consider why the starting point of the "North Mankato-Mississippi" line, f/k/a Wilmarth-North Rochester-Tremval" is proposed to start at the Wilmarth garbage burner or the North Mankato gas peaking plants. Does Xcel plan to renew the PPAs for those natural gas plants burning fossil fuel? Does Xcel plan to increase burning of garbage?¹⁷ The Commission has recently been considering increased garbage burning and "biomass," which was previously decreased as a matter of policy limiting CO2 creation, because burning garbage creates CO2 output. Biomass was also disfavored due to dreadful economics. Biomass is not cost effective and generates CO2. The biomass mandate was legislatively removed from the 1994 Prairie Island legislation and Commission related statutes – there is precedent.

On the other hand, as a Red Wing resident, this writer noticed that Xcel's IRP 12 years ago

¹⁷ See PUC Docket 23-151 and definition of "carbon free."

stated it would shutter the Wilmarth and Red Wing garbage burners.

For capacity planning and RES compliance planning purposes, we are assuming that Red Wing and Wilmarth will be retired at the end of 2012.

Attachment D, Xcel IRP, pages 6-7 to 6-8, PUC Docket RP-07-1572. Xcel apparently recanted on that assumption. Is there a plan to increase garbage incineration? If/when the Hennepin County HERC garbage burner is shut down, will that garbage burning be transferred to Wilmarth and/or Red Wing, increasing burning there? Is there a plan for increased generation in the immediate vicinity of Wilmarth? Where's the "need" for this project and why begin at Wilmarth/North Mankato?

H. NO-BUILD ALTERNATIVE

Among other things, the "no-build alternative" must be evaluated in the EIS because it may well not be needed in light of the several other projects planned for southern Minnesota. As detailed above, analysis of the "no-build alternative" must consider the now existing Split-Rock-Lakefield Jct. transmission line (01-1958); CapX 2020 Brookings-Hampton transmission including recent upgrade; CapX 2020 Hampton-La Crosse – Cardinal; and MISO's MVP 3, 4, and 5 across southern Minnesota, into Iowa, and then Wisconsin. The "new" Tranche 1 projects are, again:

- Wilmarth-North Rochester-Tremval a/k/a Mankato-Mississippi (this docket)
- Brookings-Hampton 2nd circuit upgrade – CN-23-200 & TL-08-1474
- Big Stone-Alexandria-Big Oaks – CN-22-538 & TL-23-159/TL23-160
- MN Energy CONnection – CN-22-131 & TL-22-132

I. SYSTEM AND ROUTE ALTERNATIVES OFFERED FOR CONSIDERATION

At the Pine Island hearing on July 9, 2024, Steve Hackman, of the North Route Group, offered specific system and route alternatives for the Chester 161kV line which should not only be reviewed in the EIS, but included in Certificate of Need potential system alternatives.

As a system alternative, a lower voltage option should be reviewed based on Xcel's claimed peak system demand MVA of 718, Application page 162, where proposed transmission is a gross overbuild.

No CapX 2020 and the Prehn Family offer these Initial Certificate of Need comments, and will be submitting Reply comments by April 25, 2025.

Very truly yours,



Carol A. Overland

Attorney for the Prehn Family and NoCapX 2020

OAH 65-2500-40099
MPUC E-022/CN-22-532
MPUC E-022/TL-23-157

**STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION**

**In the Matter of the Application of Xcel Energy for
a Certificate of Need and Route Permit for the
Mankato - Mississippi River 345 kV Transmission
Line Project in Southeast Minnesota**

NOCAPX 2020 AND THE PREHN FAMILY

CERTIFICATE OF SERVICE

I, Carol A. Overland, hereby certify that I have this day served a true and correct copy of the attached Prehn Family and NoCapX 2020 Initial Comment to all persons at the email addresses on the Public Utilities Commission eDockets service list by eFiling and eService.



March 28, 2025

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TESTIMONY

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2

3 A. My name is George C. Loehr, and my business address is 4101 Killington Rd. NW,
4 Albuquerque, NM 87114.

5

6 Q. BY WHOM ARE YOU EMPLOYED?

7

8 A. At present, I am self-employed.

9

10 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
11 PROFESSIONAL EXPERIENCE.

12

13 A. I received a Bachelor of Electrical Engineering degree from Manhattan College in
14 1962, and immediately began my engineering career with the Consolidated Edison
15 Company of New York, working in bulk power transmission planning. I also pursued
16 graduate studies at New York University, from which I received a Master of Arts in
17 English Literature in 1964. Also in 1964, Con Edison enrolled me in the General Electric

1 Power Systems Engineering Course (PSEC) in Schenectady, NY, which I completed in
2 1965. Following the 1965 Northeast Blackout, I was actively involved in a wide range of
3 follow-up activities. For example, I was Chairman of the Computer Committee, Federal
4 Power Commission System Studies Group, Interconnected System. My committee
5 completed an accurate computer simulation of the event – the first such successful
6 simulation of a widespread power failure in North America. I was later named Division
7 Engineer of Con Edison's Transmission Planning Division.

8
9 I joined the New York Power Authority (NYPA) as Chief Planning Engineer in 1969.
10 Up until that time, all of NYPA's system planning had been by consultants, and my first
11 assignment was to recruit and train a planning staff. I was responsible for management of
12 the planning staff and the conduct of all NYPA bulk power system generation and
13 transmission planning activities, which included load flow, transient stability, and loss of
14 load expectation studies. I also served on many New York Power Pool and Northeast
15 Power Coordinating Council committees and task forces.

16
17 I was hired by the Northeast Power Coordinating Council (NPCC) in 1972. Again, my
18 first assignment was to recruit and train a technical staff. My major responsibilities were
19 to manage the NPCC staff, which worked in support of the eight NPCC expert task
20 forces, and to advise NPCC's Joint Coordinating Committees and Executive Committee.
21 I became very active in regional, national and North American Electric Reliability
22 Council (NERC) activities, and served on numerous committees, subcommittees and task
23 forces. I also served on a Federal Power Commission advisory committee following the

1 1977 New York City Blackout. I was named Executive Director of NPCC in 1989, and
2 remained in that position until my (early) retirement in 1997.

3
4 Since retiring from the NPCC, I have done management consulting, appeared as an
5 expert witness, and taught a variety of courses on power systems – especially courses and
6 workshops for non-technical professionals. My clients have included organizations
7 throughout the U.S., Canada, and China.

8
9 At present, I am an Unaffiliated Member of the Executive Committee of the New York
10 State Reliability Council (NYSRC), and currently serve as its Chair; I formerly chaired
11 the NYSRC's Reliability Compliance Monitoring Subcommittee. In addition, I serve as
12 an Outside Director on the Board of Directors of the Georgia System Operations
13 Corporation (GSOC), and as a member of its Audit Committee. I have served as Vice
14 President and a member of the Board of Directors of the American Education Institute
15 (AEI), and I was a charter member of Power Engineers Supporting Truth (PEST).
16 I have given expert testimony in the states of Maine, Pennsylvania, New York, Vermont,
17 Kentucky, New Mexico, Mississippi, and in Washington, DC. I have done TV interviews
18 with BBC, CNN, WPIX and CBC, and have been a lecturer, keynote speaker, and/or
19 chair at professional conferences in the U.S. and Canada. In addition, I've made audio
20 tape lectures for various organizations, including the Institute of Electrical and
21 Electronics Engineers (IEEE), Professional Development Options, Red Vector, and AEI.
22 My articles have appeared widely in the trade press, including *Public Utilities*
23 *Fortnightly*, *Electrical World*, *The Electricity Journal*, *Electricity Daily*, *Transmission &*

1 *Distribution World, Energy Perspective, Restructuring Today, Energy Pulse, Natural*
2 *Gas & Electricity, EnergyBiz*, and the Belgian magazine, *Revue E tijdschrift*. I have been
3 quoted in a number of U.S. newspapers, and interviewed on Michigan public radio. *The*
4 *New York Times* published an op-ed piece of mine in 2006. I am co-editor of and a
5 contributor to the IEEE book, *The Evolution of Electric Power Transmission Under*
6 *Deregulation*.

7

8 In addition to my engineering career, I am a published author, have exhibited my art
9 photographs at galleries in the New York metropolitan area, and have done stock
10 photography for The Image Bank, a world-wide photo agency. My photos have appeared
11 in numerous magazines, advertisements, business brochures, in several “coffee table”
12 books, and as a book cover of a best seller. I recently published my own first novel,
13 *Blackout*.

14

15 Q. PLEASE EXPLAIN THE MISSION OF THE NEW YORK STATE RELIABILITY
16 COUNCIL (NYSRC).

17

18 A. The mission of the New York State Reliability Council is to promote and preserve the
19 reliability of the New York State Power System in the New York Control Area. This
20 mission includes developing, maintaining, and from time-to-time, updating the Reliability
21 Rules which must be complied with by the New York Independent System Operator and
22 all Market Participants. In fulfilling its mission, it works in close conjunction with the
23 New York Independent System Operator. It carries out its mission in accordance with

1 the New York State Reliability Council Agreement and the New York Independent
2 System Operator/New York State Reliability Council Agreement.

3
4 Q. PLEASE EXPLAIN THE MISSION OF THE NORTHEAST POWER
5 COORDINATING COUNCIL (NPCC).

6
7 A. The Northeast Power Coordinating Council (NPCC) was the first of the Regional
8 Reliability Councils formed after the Northeast Blackout in 1965. Its role was (and is) to
9 ensure the reliability of electric power systems in the northeastern United States and
10 central and eastern Canada by developing, maintaining, and monitoring conformance
11 with reliability criteria for planning and operations. It also provides a forum for the
12 coordination of planning and operating procedures. NPCC's current membership
13 encompasses New York State, the six New England states, and the Canadian provinces of
14 Ontario, Quebec, New Brunswick, Nova Scotia, and Prince Edward Island. I might add
15 that the main reason I left the New York Power Authority and joined NPCC was my keen
16 interest in reliability and reliability criteria, and my wish to contribute toward making the
17 bulk power system more reliable.

18
19 Q. PLEASE EXPLAIN THE ORGANIZATION KNOWN AS POWER ENGINEERS
20 SUPPORTING TRUTH (PEST).

21
22 A. Following the August 14, 2003 blackout, several associates and myself, each with 40
23 years or more experience in electric power system planning and reliability, decided to

1 form a group to bring out the truth about electric power system reliability. To this end,
2 we established a not-for-profit organization, which we called Power Engineers
3 Supporting Truth (PEST). As we stated in our *Principles*, which were issued in
4 September 2003, our intent was “to identify the best ways to make the bulk power
5 systems in the United States both more reliable and economic.” We published several
6 reports over the next few years, and made our reviews and recommendations available to
7 the general public, as well as to interested industry groups, government officials, and the
8 media.

9
10 Q. HAS THERE BEEN A COMMON THREAD TO YOUR TESTIMONY IN STATES
11 SUCH AS MAINE, PENNSYLVANIA, NEW YORK, VERMONT, KENTUCKY,
12 NEW MEXICO, AND MISSISSIPPI?

13
14 A. Yes. My expert testimony in the various states has focused on bulk power system
15 reliability. So have my TV and radio interviews, my articles in the trade press, and my
16 conversations with reporters and journalists.

17
18 Q. WHAT IS THE SUBJECT OF THE COURSES AND WORKSHOPS YOU NOW
19 TEACH?

20
21 A. Virtually all of my courses and workshops, my speeches and lectures, and my audio
22 tapes primarily address two subjects: how the interconnected bulk power system (or
23 “grid”) works, and the importance of keeping it reliable.

1 Q. HAS MOST OF YOUR CAREER FOCUSED ON ENSURING THE RELIABILITY
2 OF BULK POWER SYSTEMS?

3

4 A. I would say that “bulk power system reliability” is the one concept that best
5 characterizes my 47 year career. It is even the main subject of my recently published
6 novel, *Blackout*.

7

8 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY HERE?

9

10 A. I was asked by the Sierra Club to complete an independent evaluation of the PATH
11 application and determine if the applicants had proven a reliability need for the line. I
12 reviewed the PATH application, the testimony and exhibits submitted with the
13 application, and numerous discovery responses and documents from the various parties.

14

15 Q. COULD YOU SUMMARIZE YOUR VIEWS?

16

17 A. A reliability need for the proposed 765kV line has not been clearly demonstrated. My
18 major reservation is with the assumptions that underlie the contingency studies –
19 especially the conditions assumed for the base case load flows upon which the
20 contingency studies were run. More specifically:

21

22 • The applicants and PJM do not have *carte blanche* from NERC. While PJM
23 has been designated by NERC as a Planning Authority (a.k.a. Planning

1 Coordinator since 2007) and Transmission Planner, it is not authorized to make
2 whatever assumptions it wants when conducting planning studies. In my opinion,
3 the assumptions and base conditions of the applicant's and PJM's studies are not
4 credible and reasonable. Therefore, neither are the conclusions.

5
6 • PATH would not improve reliability. Rather, by making eastern load centers
7 all the way from northern New Jersey to northern Virginia more dependent on
8 remote generation and transmission lines hundreds of miles in length, PATH
9 would *exacerbate* reliability.

10
11 • PATH would effectively provide a subsidy to existing and future western
12 generators – access to the lucrative eastern load centers without cost to
13 themselves. Conversely, the western subsidies would place eastern generators at
14 a significant disadvantage. This is a clear violation of FERC's "fair and non-
15 discriminatory" principle.

16
17 • PATH would encourage remote rather than local generation by providing
18 western generators with free transmission access to eastern load centers. Existing
19 coal-fired generators would be ramped up, and new coal-fired generators would
20 be encouraged to site in the west.

21
22 • PATH's approval now, before commitments need to be made for generators and
23 other resources, would be a strong incentive to increase the output of existing

1 coal-fired plants, and for developers to build western generation. It would be a
2 disincentive for developers to site future generation and other resources in the
3 East, where they're most needed.

4
5 • PJM planning studies represent future generators which have executed only a
6 Facilities Study Agreement (FSA) if they add to a reliability problem, but require
7 the next step, an Interconnection Services Agreement (ISA), if they contribute to a
8 solution. This is a clear case of bias, and violates FERC's "fair and non-
9 discriminatory" principle. More important, it does not make engineering sense.

10
11 • The applicants seem focused almost exclusively on AC EHV transmission.
12 Non-transmission alternatives, and even other transmission alternatives like
13 HVDC, have been ignored.

14
15 • PJM's one-at-a-time planning is a piecemeal approach to solving reliability
16 problems. PJM, as the RTO, needs to step up to the plate and start planning its
17 system on a coordinated, integrated basis.

18
19 • In my view, the Load Deliverability procedure used by PJM comes up with
20 Capacity Emergency Transfer Objective (CETO) values that are unnecessarily
21 high, and seems out of synch with what the rest of the industry is doing. There
22 are better, more systematic and technically consistent ways to determine the

1 import capabilities required by Load Deliverability Areas (LDAs) to maintain
2 reliability.

3

4 • Without PATH, the capability of the Mid-Atlantic LDA to import power would
5 still be in excess of 6,000MW. In other words, with a 6,000MW transfer into the
6 Mid-Atlantic area, there would be no reliability violations. Not one.

7

8 • In my opinion, NERC violations have not been established since the base case
9 assumptions are too conservative. So, too, are the CETO/Load Deliverability
10 procedures.

11

12 • PJM's procedure for establishing CETO values is far more conservative than
13 other eastern ISO/RTOs. It's ultra-conservative when compared to New York and
14 New England.

15

16 • In general, the PJM process for assessing reliability and determining "need"
17 seems to favor extreme solutions – solutions far more massive than necessary.
18 This overkill approach violates an important engineering principle: "Don't use a
19 pile driver to hammer tacks."

20

21 • All of PJM's load deliverability testing, which it relied on in determining the
22 need for PATH, was based on a single dispatch. NERC standards call for
23 multiple dispatch scenarios: according to a NERC interpretation of Standards

1 TPL-002 and -003, “a variety of possible dispatches should be included in
2 planning analyses.”

3

4 • While NERC Planning Standards call for the system to be stressed, the
5 interpretation of “stress” must be reasonable. PJM and the applicants take the
6 concept of “stress” to unreasonable extremes.

7

8 • PATH isn’t really about reliability – it’s about economics. While western
9 generators would earn greater profits, eastern load centers would become more
10 dependent on long EHV transmission lines; thus major East Coast cities like
11 Philadelphia, Baltimore, Washington and Richmond would become more
12 vulnerable to interruptions and blackouts, either from natural phenomena or from
13 terrorist attacks.

14

15 • The alleged “voltage stability” problems have not been proven. We’ve been
16 shown “knee-of-the-curve” results from steady state load flows, but no actual
17 time-domain stability results. The alleged voltage violations are also based on the
18 unnecessarily high CETO values. At more realistic CETOs, there would be no
19 violations.

20

21 • Other than construction of the 765kV PATH line, solutions to the alleged steady
22 state voltage violations have not been addressed. Apparently, neither power

1 factor improvements by adding capacitors at the distribution and subtransmission
2 level, nor shunt capacitors at 115/138kV substations, have been considered.

3

4 • Despite the fact that the latest “re-tool” analyses show different violations
5 occurring on lower voltage facilities in a time-frame further out in the future, no
6 alternatives to PATH as originally proposed have been examined.

7

8 • Conclusions regarding reliability violations beyond the 2014 study year were
9 based on extrapolated results. In my opinion, this is not an acceptable way to
10 assess the reliability of plan the bulk power transmission system.

11

12 • The PATH “solution” is not consistent with the alleged need to improve
13 reliability. To improve reliability, PJM needs to promote the location of
14 generation and other resources close to the load centers, rather than build a
15 transmission line which will provide an incentive for the construction of
16 generation, probably coal-fired, hundreds of miles away.

17

18 • The *real* reliability problem in PJM is the present high dependence of the
19 eastern load centers on remote generation and multiple EHV transmission lines,
20 each hundreds of miles long. *This* is the problem PJM should be addressing;
21 instead, PJM is pursuing policies which will make the problem worse.

22

23

1 Q. PLEASE EXPLAIN THE HISTORY AND BASIC CONCEPTS INVOLVED IN
2 BULK POWER SYSTEM PLANNING AND RELIABILITY

3
4 A. Among the more important considerations when dealing with large power systems are
5 the reliability standards or criteria used for planning and operations. These have been an
6 integral part of the electric power industry since the very first systems were developed in
7 the late 19th Century, but they became increasingly important as power systems expanded
8 and merged to form what we now know as synchronous interconnections, or simply
9 “grids.”

10
11 Early “central station” systems were relatively simple. A major disturbance or
12 “contingency” could, at worst, shut down electric service in a small area – e.g., one
13 square mile. But the introduction of high voltage alternating current technology
14 permitted the use of long lines at higher voltage. This led to power systems which
15 spanned progressively larger areas. Also, systems found it advantageous to share
16 generating reserves, and minimize reliability risks from transmission problems, by
17 interconnecting with each other.

18
19 This process took place through most of the 20th Century until, by the early 1960s, power
20 systems in most of the U.S. and Canada had coalesced into four large synchronous
21 interconnections or “grids.” The largest of these, the Eastern Interconnection, stretches
22 from the Canadian Maritimes to Florida, and from the Atlantic Ocean roughly to eastern
23 Montana, Wyoming, Colorado and New Mexico. It encompasses all eastern, central and

1 prairie provinces of Canada except Quebec and Newfoundland. The Western
2 Interconnection runs from the Rockies to the Pacific Coast, and includes the Canadian
3 provinces of Alberta and British Columbia, as well as a small portion of the northern Baja
4 in Mexico. The ERCOT Interconnection comprises approximately 75% of the state of
5 Texas. Finally, the Quebec Interconnection consists of that province in its entirety.

6
7 Power system planning begins with today's system – electric system planners do not have
8 the option of throwing away last year's (or last decade's) thinking and starting over from
9 scratch. So the power system as it exists is the starting point. Along with that, planners
10 must begin with today's system demand levels, and predict or "forecast" how customer
11 actions will affect electric demand in the future. In the present "deregulated" or
12 "restructured" electric power industry, the ownership of generating resources in many
13 states is separate from the ownership of the bulk power transmission system. Generation
14 is also competitive – various companies vie with one another in an open market.

15
16 There are two aspects to effective reliability: "resource adequacy," having enough
17 generation and other resources to meet the customers' electrical demand; and
18 "transmission reliability," the ability of the transmission system to deliver the power and
19 withstand sudden contingencies without overloads, low voltages, instability, or loss of
20 customer load. To meet these twin goals, power systems must establish certain standards
21 for both planning and operations.

1 Resource adequacy (generation, DSM, etc.) is determined on a probabilistic basis. In
2 most North America systems, the generally applied standard is “one day in ten years.”
3 This means that sufficient resources must be available to serve all firm customer demand
4 on all but one day over a ten year period. Resource adequacy problems, or shortages in
5 generating capacity and other resources, can lead to voltage reductions (or “brownouts”),
6 public appeals, and rotating feeder outages. By their nature, they can usually be
7 anticipated in advance, and actions taken ahead of time.

8
9 Transmission reliability is assessed on a deterministic basis. Transmission planning
10 standards or criteria specify a variety of specific disturbances or “contingencies” – the
11 bulk power system must be able to withstand any of these without adverse consequences.
12 Failures of the transmission system can lead to overloads, cascading outages, instability,
13 system separations – and total blackouts over widespread areas. They almost always
14 occur without warning, and can rarely be anticipated; hence, preventive actions, other
15 than scrupulous adherence to standards and criteria, generally are not possible.

16
17 Blackouts are usually caused by contingencies more severe than those specified in the
18 applicable standards or criteria, by equipment failures, control system problems, human
19 error, or some combination of these. They involve the break-up of the bulk power
20 transmission system. Blackouts are not caused by shortages of generating capacity.

21
22 During the first half of the 20th Century, individual power systems each developed and
23 applied their own planning criteria. By mid-century, however, with the dramatic growth

1 of synchronous interconnections and the increasing use of the system to transmit power
2 over long distances, the limitations of such an approach were becoming obvious. When
3 the Northeast Blackout of 1965 occurred, it was plain to see that a more coordinated
4 approach was necessary.

5
6 PJM, which had a much smaller footprint in 1965 than it has today, was already
7 functioning with a uniform set of criteria. The systems involved in the 1965 blackout
8 soon followed suit. Shortly after the blackout, they formed the Northeast Power
9 Coordinating Council (NPCC). Other utilities across North America also formed their
10 own regional reliability councils, which eventually encompassed most of the continent.

11
12 Each regional council established its own reliability criteria. Each also developed
13 procedures for assessing conformance. Individual systems and power pools sometimes
14 developed their own more detailed or more stringent criteria, but they were always
15 responsible for adherence to the regional criteria as a minimum.

16
17 The regional reliability councils formed the National Electric Reliability Council (NERC)
18 in 1968 to coordinate their activities nationally and develop overall reliability guidelines
19 for their collective systems. NERC has evolved over the years. As additional Canadian
20 systems became members, it became the North American Electric Reliability Council.

21 But the most dramatic changes occurred in the wake of the August 14, 2003
22 Midwest/Middle Atlantic blackout. The Energy Policy Act of 2005 (EPAct) directed
23 FERC to establish an Electric Reliability Organization (ERO). Its major role would be to

1 develop and enforce mandatory reliability standards for planning and operations. After a
2 period of study, FERC designated NERC as the ERO, and its name was changed to the
3 North American Electric Reliability Council Inc.

4
5 Today, NERC develops reliability standards, which must be approved by FERC. The
6 regional reliability councils may have their own criteria, but these must conform to
7 NERC's. As provided by EPAct, compliance with NERC standards is mandatory. ISOs,
8 RTOs and individual utilities, as well as all other market participants like generators and
9 power marketers, are members of the regional reliability councils and must comply with
10 both the regional criteria and NERC standards.

11
12 NERC planning standards require both short- and long-term studies. Any violations
13 discovered in the short-term analyses must be addressed with appropriate solutions. On
14 the other hand, the purpose of the long-term studies is to provide some indication of the
15 nature and direction of future reliability problems, and to ensure that any recommended
16 short-term solutions will be consistent with future needs.

17
18 Q. HOW ARE STANDARDS AND CRITERIA USED IN TRANSMISSION
19 PLANNING?

20
21 A. The first step in evaluating the potential reliability need for new facilities is to
22 investigate the existing transmission system for a chosen future year, with existing and
23 planned generating resources added, along with any transmission additions already

1 scheduled. First, power flow or “base load flow” cases are created, representing base
2 conditions – generally, peak loads under various generation scenarios. Then, new load
3 flow cases are run simulating a wide range of potential disturbances or contingencies.
4 The results of these contingency load flows will indicate where and to what extent the
5 existing system needs reinforcement. At this point, familiarity with the system and
6 engineering judgment will usually suggest potential solutions to the violations, and
7 typically several will be chosen for further scrutiny. The most successful enhancement
8 will be chosen, consistent with a parallel cost-effectiveness analysis. Finally, non-
9 transmission alternatives should also be identified and examined, and compared in terms
10 of cost, reliability, and environmental impact with the preferred transmission solution.

11
12 One of the key questions is how severe the contingencies should be. Over the past fifty
13 years, planning engineers have reached a consensus on what is commonly known as
14 “worst single contingency” design – a.k.a. “n-1.” This means that the system must be
15 able to survive the worst single event which could happen to the bulk power system.
16 Typically, this is the loss of a large generating unit, or a three-phase fault on a major
17 transmission line or autotransformer. But the devil, as is said, is in the details.

18
19 Current NERC standards allow the planning entity a degree of judgment. NERC’s TPL-
20 002 and TPL-003, for example, require that the pre-disturbance system be *stressed*;
21 however, the nature of the “stress” is not defined – despite several requests from
22 transmission companies for a more definitive interpretation. It’s up to the planning entity
23 to fill in the details.

1 Specifically, NERC states in its February 8, 2005 interpretation of Standards TPL-002
2 and -003 that “a variety of possible dispatches should be included in planning analyses.”
3 NERC also specifies that the “selection of ‘critical system conditions’ and its associated
4 generation dispatch falls within the purview of [the Planning Coordinator’s]
5 ‘methodology.’” Finally, NERC directs that “a Planning Coordinator would formulate
6 critical system conditions that may involve a range of critical generator unit outages as
7 part of the possible generator dispatch scenarios.” One of the problems I have with the
8 PJM approach is that only a single dispatch is used for all of the load deliverability
9 analyses relied on in this proceeding.

10
11 Base conditions provide another example where the planning entity’s judgment is
12 required. This would include assumptions regarding appropriate load level, the handling
13 of proposed new generation, the potential retirement or older generating units, and the
14 dispatch of the overall system. Dispatch scenarios, which can be viewed as the bridge
15 between “adequacy” (sufficiency of resources) and “operating reliability” (transmission
16 reliability), are of particular interest. Generally, the best approach is to examine several
17 different dispatch scenarios – varying the components and applying the most serious
18 contingencies in each example.

19
20 Many planning entities today use a so-called “90/10” load forecast, as opposed to a
21 “50/50” forecast, as one of many ways to satisfy the NERC “critical system conditions”
22 requirement. This means that there is a 10% probability that the actual load will exceed
23 the forecast demand, and a 90% probability that the actual peak demand will be lower.

1 In conducting planning studies, the critical contingencies as defined by the NERC
2 standards are applied to the modeled system for each chosen scenario. Some of these
3 contingencies will involve the sudden loss of a single element (n-1) – this could be a
4 generating unit, critical transmission line, transformer, or any other power system
5 component. Others contingencies will cause simultaneous loss of two related elements –
6 such as both circuits of a double-circuit transmission line. Since the loss of both elements
7 is caused by a single event, these are also referred to as n-1 contingencies. A few will
8 involve the loss of two unrelated elements (n-1-1), with manual system adjustments
9 between the two contingencies (usually within 10 minutes). Regardless of the
10 contingency applied, the system must suffer no overloads, low voltages, cascading
11 outages, instability, system separation or loss of firm customer load before adjustment.

12
13 Q. ARE THE RELIABILITY STANDARDS MANDATED BY NERC?

14
15 A. For some time, NERC has developed reliability standards for planning and
16 operations. As a result of the Energy Policy Act of 2005 (EPAct), these are now
17 mandatory under federal law. The NERC planning standards define the contingencies
18 which the power system must be able to survive without significant adverse
19 consequences – overloads, low voltages, instability, system separations, or blackouts.
20 However, the NERC standards do *not* define the configuration of the system to which
21 these contingencies are applied, other than to say that the system must be stressed –
22 assumed base conditions must “cover critical system conditions and study years as
23 deemed appropriate by the responsible entity.” [NERC Standards TPL-002-0 and TPL-

1 003-0.] But the nature of the “critical system conditions” must be credible and
2 reasonable.

3
4 NERC has designated various entities, including PJM, as Planning Authorities (Planning
5 Coordinators) and Transmission Planners, as described in the NERC Functional Model.

6 These are responsible for deciding how their systems will be configured – stressed – for
7 application of the NERC contingencies. As NERC has stated, “The selection of a
8 credible generation dispatch for the modeling of critical system conditions is within the
9 discretion of the Planning Authority.” [March 13, 2008 NERC Planning Committee
10 interpretation of TPL-002-0 and TPL-003-0.] The language here (e.g. use of the word
11 “credible”) clearly indicates that the assumptions must have a basis in reality.

12
13 NERC does not scrutinize the manner in which the PJM or any planning entity’s system
14 is represented. Neither does FERC. NERC and FERC are not the drivers – the applicants
15 and PJM are the drivers. And they must answer for the base system assumptions they
16 have made.

17
18 In my opinion as an expert, the manner in which PJM and the applicants configured the
19 PJM system prior to the application of contingencies went considerably beyond what I
20 consider reasonable. If the base assumptions are not credible, then the contingency
21 analyses based on them are not credible – even though the applied contingencies are
22 those specified in the NERC standards. A house built on sand will not stand. The PATH
23 studies are built on sand; they’re based on assumptions, how the PJM system is

1 represented, which are neither credible nor reasonable. Therefore, neither are the
2 conclusions.

3

4 Q. BUT NERC HAS DESIGNATED PJM AS A PLANNING AUTHORITY AND
5 TRANSMISSION PLANNER. DOESN'T THAT GIVE PJM AUTHORITY TO MAKE
6 THESE DECISIONS?

7

8 A. Not completely – the assumptions must be credible and reasonable. NERC's
9 designation of PJM and other entities as Planning Authorities and Transmission Planners
10 does not give them *carte blanche* to make whatever assumptions they want when
11 conducting reliability assessments and planning studies. NERC neither supports nor
12 condemns PJM's decisions about base conditions – the PJM Load and Generation
13 Deliverability procedure, for example. NERC doesn't endorse *any* planning entity's
14 specific approach. Therefore, the applicants cannot hide behind PJM's designation as a
15 Planning Authority and Transmission Planner to support the need for PATH.

16

17 Q. DO YOU BELIEVE THE PATH VIOLATIONS ARE REASONABLE?

18

19 A. No. The alleged violations are based on the applicants' initial assumptions, and in my
20 view those are *not* reasonable. Why I believe that the procedures used in the PATH
21 studies are not reasonable is covered in the remainder of my testimony. But the major
22 objection I have is with what I consider an overly conservative process for determining
23 the Capacity Emergency Transfer Objective (CETO), leading to an import target for the

1 LDA which is unnecessarily high. When the load flows are run to determine if there are
2 any NERC violations, they use this import value; since it's unnecessarily high, finding
3 "violations" is practically guaranteed. With a more reasonable import value, neither
4 thermal nor voltage violations will be found.

5
6 Overall, PJM's and applicants' procedures are overly conservative. They pile
7 conservative assumptions on top of conservative assumptions – beyond what, in my
8 opinion, is reasonable. In brief, they push the "conservative" envelope too far.

9
10 Q. PLEASE COMMENT ON THE USE OF "CAPACITY EMERGENCY TRANSFER
11 OBJECTIVE" BY PJM AND THE APPLICANTS.

12
13 A. For any defined Load Deliverability Area (LDA), PJM does a Loss of Load
14 Expectation (LOLE) study to determine the import capability necessary to maintain a
15 "one day in 25 years" LOLE. This is then called the Capacity Emergency Transfer
16 Objective (CETO) for that LDA. The CETO value is based, among other things, on the
17 load forecast. A mean or median schedule is developed for the LDA, using the same
18 probabilistic statistics as in the LOLE, to accommodate an import equal to the CETO.
19 Next, load flow cases are run at that value, simulating the various requirements of NERC
20 Planning Standards TPL-001, -002, and -003. If the existing transmission system results
21 in "violations" for any of these (A, B, and C), the planners conclude that a transmission
22 reinforcement is required. PJM maintains that they're only permitted to consider
23 transmission reinforcements.

1 In theory, the Capacity Emergency Transfer Objective (CETO) is the amount of import
2 capability which the LDA geo-electric area would require to allow it to satisfy a chosen
3 loss of load expectation, given its load characteristics and the amount of generation it
4 contains.

5
6 Mr. McGlynn discusses the Mid-Atlantic LDA at some length in his testimony. He cites
7 the Mid-Atlantic LDA's CETO used in PJM's April 2009 modeling as 8,190MW
8 [McGlynn, page 28.]. In my opinion, the 8,000MW+ value he comes up with as the
9 CETO is breathtakingly (and unnecessarily) high. That's an awful lot of power to
10 transfer into eastern PJM from the West. It's a very large value to expect to export to *any*
11 single area – something like one MW for every eight MWs of peak load. One has to ask
12 if this is really a reliable way to supply a high percentage of the electric requirements of a
13 metropolitan area that stretches from northern New Jersey to northern Virginia. That
14 entire megalopolis would be subject to interruption by many and diverse causes, natural
15 and human, intentional as well as unintentional. The present import capability of the
16 Mid-Atlantic LDA is in excess of 6,000MW – a pretty high number itself. (Exhibit
17 PFM3 lists the most restrictive contingency at a Mid-Atlantic LDA import of 6,240MW.)
18 In other words, without PATH, it would still be possible to send more than of 6,000MW
19 into eastern PJM. According to the PATH response to SierraVA-IV-61, there is
20 67,635MW of generating capacity in the Mid-Atlantic LDA as of October 2009 – *right*
21 *now*. Given this amount of *existing* generating capacity, not even counting whatever
22 additional capacity will be added over the next five years, why isn't a 6,000MW CETO
23 enough? PJM should place greater emphasis on incenting new generation to locate

1 within the Mid-Atlantic LDA, which would provide greater reliability to the eastern load
2 centers.

3
4 In responding to the VASStaff-V-5 request for updated data on the Mid-Atlantic LDA,
5 PJM cited a lower peak load forecast for 2014, an 827MW increase in installed capacity,
6 and a lower CETO value – 7,720MW. This CETO reduction of 470MW further reduces
7 any alleged “need” for the PATH line.

8
9 PJM’s “one day in 25 years” standard – used to come up with the CETO number – is also
10 questionable. This is a conservative assumption, PJM admits – part of the need to
11 “stress” the system. To my knowledge, no other RTO or ISO uses a value this high.

12 Why shouldn’t PJM use “one day in 10 years,” like everyone else? By comparison, one
13 day in 25 years is a higher standard than that used by either ISO New England or the New
14 York ISO, each of which is only about half the size of the Mid-Atlantic LDA. And this is
15 on top of a 90/10 load representation, which would be expected to occur only once every
16 ten years. PJM seems to pile one conservative assumption on top of another.

17
18 In fact, I would question whether a criterion of “one day in 10 years” for all of PJM is
19 itself overly conservative, given the large size of the expanded PJM system. The New
20 England and New York ISOs each use an adequacy criterion of one day in 10 years, yet
21 each is approximately one-fourth the size (in MWs) of the PJM system. Standardized to
22 the PJM peak load, New England and New York at one day in 10 years would be
23 equivalent to *four* days in 10 years. New York and New England include metropolitan

1 areas at least as critical as PJM's; why should PJM use a much more conservative
2 reliability criterion? In my opinion, it would not be unreasonable for PJM to use a less
3 conservative criterion, more in keeping with its peak load relative to other ISO/RTOs like
4 the New York ISO and ISO New England. For example, just by changing from a
5 criterion of one day in 25 years to one day in 10 years for the Mid-Atlantic LDA, and
6 putting it on the same loss of load expectation basis as New York and New England, PJM
7 could lower the CETO for the Mid-Atlantic LDA by approximately 3,000MW.

8
9 There are other, and in my opinion better, ways to do this kind of analysis. For example,
10 when it studies the LOLE of the entire PJM system to calculate the required installed
11 reserve margin, PJM uses a multi-area probabilistic program. It does not model separate
12 areas within PJM, however. PJM could use the same program to model all the LDAs
13 along with the existing transmission transfer capabilities between them, and still target an
14 overall LOLE criterion. A need to increase any of the inter-area transfer capabilities
15 would be evident from such an analysis. Thus PJM could unify the process, and also
16 meet the desired objective vis-à-vis the overall PJM system.

17
18 In fact, PJM's process for addressing reliability "need" is far more conservative than
19 necessary. In an earlier case (the proposed Prexy facilities in southwestern
20 Pennsylvania), this overly conservative approach led to a recommendation for a major
21 new 500kV transmission line, which was approved by PJM. In my opinion, such a high
22 voltage facility was clearly unnecessary, and I testified to this during the proceedings.
23 After the state hearings were mostly concluded, the PUC ordered a voluntary

1 collaborative effort. This led to a much simpler, less expensive, and less environmentally
2 intrusive solution involving modifications to the local 138kV system and the addition of
3 shunt capacitors.

4
5 The proposed Prexy Facilities were to consist of a new 500kV substation in Washington
6 County called "Prexy", a new 500kV transmission line (36 miles long) in Washington
7 and Greene counties, and three new 138kV lines (running 15 miles) to connect the
8 proposed new substation to the existing transmission system. After the collaborative
9 process, the approved fix reinforced the electric grid without any new 500 kV lines,
10 substations, or 138 kV lines. Instead, it involved installing one new monopole on an
11 existing utility right of way (to allow the connection of two existing lines), adding
12 equipment (capacitors) at five existing substations, and replacing the conductors on 2.5
13 miles of existing 138 kV lines. The estimated cost for the agreed-upon fix is \$11.6
14 million, instead of \$213 million for the proposed Prexy Facilities. And the
15 solution solved the same reliability issues that were "driving the need" for the previously
16 proposed "Prexy Facilities."

17
18 PJM's approval of the need for Prexy facilities, and PATH in this proceeding, violated an
19 engineering principle which a former professor of mine used to insist on: "Don't use a
20 pile driver to hammer tacks."

1 Q. WOULDN'T THERE BE VIOLATIONS OF THE MANDATORY NERC
2 STANDARDS IF PATH IS NOT BUILT?

3

4 A. Not at all. Whether or not violations will occur ultimately depends on the value
5 selected for the CETO. This applies to voltage as well as line loading violations. There
6 would be *no* violations of NERC Standards if realistic CETO values were used. The only
7 reason that "violations" were identified in PJM's studies is that PJM was trying to cram
8 too much power from outside (essentially western PJM) into the eastern LDAs by using
9 unnecessarily high CETO values. It's sort of like a mouse trying to swallow a lion. For
10 the Mid-Atlantic LDA, without PATH, a 6,000MW CETO would result in zero
11 violations. Zero. And the Mid-Atlantic area would still be capable of importing over
12 6,000MW.

13

14 As I see it, based on my more than 47 years of experience in transmission planning and
15 reliability assessment, eastern PJM is *already* too dependent on western generation – this
16 is the *real* reliability problem, and a major reliability risk.

17

18 In my opinion, PJM faces a reliability problem – a *serious* reliability problem – which
19 will worsen if PATH is built. It's the overdependence of the eastern PJM load centers on
20 generating units hundreds of miles to the west. The megalopolis from northern New
21 Jersey to northern Virginia is over-dependent on long transmission lines, any one of
22 which could be taken out of service by natural or human agents. This is a *major* problem
23 that needs to be addressed. And it's a *national security problem* as well. PJM should, in

1 my opinion, develop a program to address this problem as soon as possible – but instead
2 PJM is pursuing policies that will only make the problem worse.

3

4 Q. WOULDN'T PATH, IN AND OF ITSELF, INCREASE RELIABILITY ANYWAY?

5

6 A. No. Rather than *increase* reliability, PATH would actually make it *worse*. Eastern
7 load centers from Boston to northern Virginia comprise what urban planners sometimes
8 call a linear city or megalopolis. It's essentially one continuous metropolitan area.
9 Within this linear city, the area from northern New Jersey and Philadelphia to
10 Washington and northern Virginia is part of PJM. If PATH is approved, generating
11 companies will be given a powerful incentive to site new generators in the Allegheny
12 coal fields, hundreds of miles to the west, rather than in or close to the eastern load
13 centers. Even existing coal-fired generators will have the opportunity to ramp up their
14 outputs. This will make the eastern megalopolis even more dependent on remote
15 generation resources than it already is. Cities like Newark, Philadelphia, Wilmington,
16 Baltimore, Washington and Richmond will depend for their electric supply on generators
17 hundreds of miles away. I've been in electric power transmission planning and reliability
18 for more than 47 years, but you don't have to be an engineer to understand that this is a
19 less reliable situation than if the resources were located nearby. It's like running an
20 extension cord down the block to plug your toaster into a neighbor's outlet rather than
21 using an outlet in your own kitchen. The long transmission lines are vulnerable to all
22 sorts of interruptions – including terrorist attack – so this is a national security issue as
23 well as a reliability concern.

1 More transmission does not equal a higher level of reliability. Consider two hypothetical
2 transmission systems: one a system with a lot of transmission lines, but planned and
3 operated to *less* stringent reliability standards; the other a system with very little
4 transmission, but planned and operated to *more* stringent reliability standards. The first
5 system would be less reliable than the second system, because it uses less stringent
6 reliability standards. Reliability is not a function of the amount of wire in the air.

7

8 Now consider what happens when transmission is added. The apparent electrical
9 impedance across the grid is reduced, in effect making it electrically tighter. Thus a
10 given contingency could have a more widespread effect. By increasing the amount of
11 west-to-east transmission in PJM, the proposed PATH line would make the Eastern
12 Interconnection subject to larger blackouts.

13

14 This can be visualized in a more technical light. The key factor in the stability of a
15 system is the electrical angle between generators. Building transmission lines reduces the
16 equivalent electrical impedance between generators – the units become electrically
17 closer, and the angle is decreased, which tends to make the system more stable.

18 However, stability will be improved *only if no additional power is scheduled across the*
19 *system*. If the power flow is increased, then the angle is increased, and the units will be
20 electrically further apart, making the system less stable. My own experience after doing
21 this kind of analysis since the early 1960s is that, even if the impedance is decreased and
22 the power flow increased such that the electrical angles are the same, the system will still
23 be more vulnerable to extreme emergency contingencies – those that are more severe

1 than the criteria used in planning and operations, and which are either the major cause or
2 an important contributing cause of nearly all bulk power system blackouts.

3
4 When systems build more transmission only to accommodate higher levels of transfer,
5 they push the system harder. The likelihood of instability is increased; the system is
6 more likely to suffer a blackout if an unforeseen contingency occurs, and the blackout is
7 likely to be larger and more damaging. In my opinion, PJM has not proven a reliability
8 problem that requires the construction of PATH, or that PATH will make the overall
9 system more reliable. However, instead of building the PATH line, reliability could be
10 *improved* by promoting additional generating capacity and other resources in the East,
11 close to the load centers. Lower west-to-east transfers across the PJM system would
12 significantly reduce the angle between generators, making the northeast quadrant of the
13 Eastern interconnection less susceptible to instability and blackouts.

14
15 Q. DO YOU THINK THAT PJM PLACES TOO MUCH EMPHASIS ON EXTRA
16 HIGH VOLTAGE (EHV) TRANSMISSION LINES?

17
18 A. Very definitely. PJM seems to see EHV AC transmission not as the *best* solution to
19 reliability problems, but as the *only* solution. Under the current PJM cost allocation
20 rules, all transmission facilities at 500kV and higher are “socialized” – i.e. their costs are
21 charged to all the Load Serving Entities (LSEs) in PJM essentially in proportion to their
22 electric loads. This means that all customers throughout the PJM area will pay the
23 construction costs for PATH. Because of this “socialization,” PATH will provide

1 existing and future western generators, including coal-fired generators, with free access
2 to the eastern load centers. In effect, western generators will be subsidized at the expense
3 of the ratepayers. It's also a case of discrimination against generators and other resource
4 providers in the East.

5
6 In other words, western generators will be given market access to eastern load centers
7 without having to pay the cost of providing that access. Customers throughout PJM will
8 bear the full cost of the new transmission. Western generators, both existing and future,
9 will be able to compete with eastern resources without paying for the transmission that
10 makes it possible. This will skew the economics of electric generation supply by
11 subsidizing some generators at the expense of others – and ultimately at the expense of
12 ratepayers. This is not the “fair and non-discriminatory” market that FERC envisaged in
13 promoting “deregulation.”

14
15 Q. IT HAS BEEN SAID THAT TRANSMISSION PROJECTS MUST BE APPROVED
16 EARLY ON, SINCE THEIR LEAD TIMES ARE NOW LONGER THAN LEAD
17 TIMES FOR GENERATORS.

18
19 A. That's true, but early approval of transmission has another, unanticipated
20 consequence. Transmission lead times are now longer than the lead times for generators.
21 That means that transmission projects will generally be approved before generators or
22 other resource providers need to make their commitments. In other words, generating
23 companies can wait until a major transmission line is approved or disapproved before

1 deciding whether to build new generating units in the East or West. If a new line is not
2 planned, or a proposed line isn't approved, developers could site new units in the East,
3 where long EHV lines would not be required to reach load centers. On the other hand, if
4 a line *is* approved, developers are likely to build in the West, where it would be less
5 expensive, since they will be provided transmission access to the eastern load centers at
6 no cost to themselves.

7
8 Such transmission approvals would foreclose other options, including generators sited in
9 the East, load management systems, and greater reliance on Reliability Pricing Model
10 (RPM) solutions in general.

11
12 In summary, PATH would provide a strong disincentive to anyone considering locating
13 generation or other resources in eastern PJM, and a correspondingly strong incentive to
14 build coal-fired generation in western PJM. The seeming obsession with transmission
15 solutions will not only provide an effective subsidy to existing generators in the West, but
16 it will act as a magnet for siting future generators there, as opposed to locating in the
17 East, where they are really needed.

18
19 Q. ARE THERE ANY OTHER EXAMPLES OF DISCRIMINATION IN THE
20 ASSUMPTIONS UNDERLYING THE PATH STUDIES?

21
22 A. Yes. To me, an egregious example of PJM's discrimination is how the representation
23 of planned, future generators is handled. In its planning studies, PJM represents only

1 those generators which have executed a Facilities Study Agreement (FSA). To be
2 represented in the studies, generators which would contribute toward the solution of a
3 reliability problem must also have executed an Interconnection Services Agreement
4 (ISA), the next step after the FSA. However, generators which exacerbate a reliability
5 problem are represented even if they have *not* received an ISA. This is patently
6 discriminatory, and in my view is a direct violation of FERC's "fair and non-
7 discriminatory" principle. In defense of this procedure, Mr. McGlynn testifies that more
8 than 75% of all proposed generators eventually drop out, but adds that "5% of requests
9 drop out after an FSA is executed." [McGlynn, page 13, line 2] Mr. McGlynn testifies
10 that only 5% of requests drop out between the execution of an FSA and an ISA. *By*
11 *McGlynn's own admission*, there's very little difference between the number of
12 generators that complete FSAs and those that complete ISAs – a mere 5%.

13
14 In my opinion, no distinction should be made. Any generator which has an executed
15 FSA should be represented, regardless of whether it exacerbates or solves reliability
16 problems. To intentionally discriminate against the very generators which could solve
17 reliability problems is both foolish and potentially costly. It goes against one of the most
18 important principles of FERC and deregulation – that all generators must be treated in a
19 manner that is both fair and non-discriminatory. Finally, again in my opinion, it
20 represents very poor engineering. Good engineering is premised on even-handedness –
21 PJM's biased handling of future generators, based on whether each would contribute to a
22 problem or its solution, tilts the science toward a presumably desired conclusion which
23 might not be proven by a fair and non-discriminatory approach. This constitutes a bias

1 towards transmission and in favor of western coal-fired generators and against eastern
2 generators and other resources; it is not even-handed at all. Political and economic
3 motives should not be permitted to interfere in the engineering. As I say in my courses,
4 “When the Laws of Physics and the Laws of Economics collide, Physics wins.”

5
6 Q. DID THE APPLICANTS CONSIDER SUFFICIENT ALTERNATIVES TO PATH?

7
8 A. The testimony of the applicants’ witnesses indicates that the only alternatives
9 seriously considered during the 2007 RTEP were other AC EHV transmission lines. No
10 alternatives involving non-transmission resources (generation, additional DSM, etc.) in
11 the East, close to the load centers, were examined, even though they might offer distinct
12 advantages in terms of cost, reliability, and environmental impact. Little recognition
13 seems to have been paid to PJM’s Reliability Pricing Model (RPM) process – despite the
14 fact that one of its stated purposes is to provide incentives for generators to locate near
15 the eastern load centers. PJM argues that it is not permitted to *order* anything other than
16 transmission – but it certainly could develop policies that would *encourage* non-
17 transmission solutions. Eastern resources seem to rate second-class status as compared to
18 AC EHV transmission. No attention was even paid to transmission alternatives other
19 than alternating current (AC) 500 and 765kV. High Voltage Direct Current (HVDC)
20 alternatives were totally ignored in 2007 – despite HVDC’s obvious advantages, and its
21 utilization for other projects in PJM (e.g. Neptune and MAPP). PJM’s planning process
22 seems to be wearing blinders – any alleged reliability problems will be addressed by the
23 “same old same old” EHV transmission solutions.

1 Somewhat belatedly, a “PATH HVDC Conceptual Study” has been initiated. Since this
2 was not mentioned in any of the witnesses’ testimony, we can safely conclude that
3 HVDC was not considered as an alternative while the PATH studies were being
4 conducted, and not evaluated at the time the decision was made to recommend PATH as
5 a 765kV, AC project.

6
7 In addition, PJM’s 2009 “re-tool” cases came up with different limiting elements than
8 those relied on for the “need” assessment. These were generally on lower voltage
9 facilities, and occurred further out in time. These differences alone should have
10 suggested that other alternatives need to be explored. But they did not. In brief, the need
11 for PATH was based on problems that no longer exist.

12
13 Q. WOULD YOU COMMENT ON PJM’S ONE-AT-A-TIME TRANSMISSION
14 PLANNING?

15
16 A. I would describe PJM’s approach to solving its alleged reliability problems as a
17 piecemeal one. In recent years, we’ve witnessed a succession of proposals to build EHV
18 transmission projects in PJM, each designed to solve a list of alleged reliability
19 violations. It seems that no attempt is made to address the problems on an overall,
20 integrated basis. Once a project is approved, it becomes cast in concrete. We’re told it
21 will take care of everything. Until the next one, that is. There never seems to be an
22 attempt to look at what combination of solutions could solve *all* reliability
23 problems/violations with a single overall solution or a set of integrated solutions. Nor

1 does there appear to be any attempt to examine whether a new proposal, perhaps with
2 some modifications, might obviate the need for one already approved.

3
4 It seems to me common sense that planning on a piecemeal basis will inevitably result in
5 more facilities being built than would really be necessary to meet the requirements of
6 NERC and other reliability standards. Perhaps a simple, hypothetical example will make
7 this more understandable.

8
9 Let's assume that a planning entity follows a "piecemeal" approach. It studies its system,
10 identifies certain reliability violations, and determines that a particular new facility would
11 solve them. Let's assume it gains approval for that facility, and adds that facility to its
12 base assumptions. It then begins another reliability study, and discovers another set of
13 violations. A second facility is planned to fix these violations – it's also approved, and
14 added to the base. A third study is conducted, and a third set of violations appears – and
15 a third facility is identified and added to the base system. And so on through, let's say,
16 seven studies and seven facilities. Is it not common sense that, had the planners looked at
17 the *entire* system, and identified *all* reliability violations, they would almost certainly
18 have been able to develop an "integrated," multi-facility solution which included *fewer*
19 required elements than the earlier, piecemeal approach? A piecemeal approach is neither
20 the best nor most efficient way to plan a system – more facilities will invariably be found
21 to be "needed" than truly would be. That's because the second (or third or fourth) facility
22 may prove to be an efficacious solution to the problems which drove the need for the first

1 (or second or third). The net result will be an overbuilt system, with all the attendant
2 economic, social and environmental consequences.

3
4 This bias or tendency toward “piecemeal,” one-at-a-time transmission planning is a grave
5 weakness of the current RTEP process in PJM.

6
7 Further, the piecemeal, cast-in-concrete approach forecloses other options. Each new
8 facility goes into all the models, and is assumed in place for all the capacity auctions.
9 Even the possibility of delay or cancellation is ignored. If *uncertainty* is viewed as an
10 important factor for the representation of new generating units, it should also be included
11 for proposed transmission additions.

12
13 There’s another problem here. Once PJM, acting as the RTO, has identified one or more
14 violations, it goes to the appropriate transmission owners (TOs) in whose systems the
15 violations occur and in effect orders them to develop a solution. This kind of
16 Balkanization does not serve the interests of overall reliability with minimum expenditure
17 for new facilities. It’s essentially a corollary to piecemeal, one-at-a-time planning. It
18 seems to me that PJM should be more involved in developing overall solutions – and
19 taking a second look at prior solutions, too.

20
21 Q. WOULD ADDING TRANSMISSION CAPACITY INTO THE EASTERN LOAD
22 CENTERS MAKE THEM MORE RELIABLE?

1 A. No. Not if the added transmission results in the load centers being more dependent
2 on remote generation. The more Philadelphia, Baltimore, Washington and Richmond
3 must depend on long distance transmission, the more vulnerable they will be. And lower
4 reliability is an inescapable consequence of greater vulnerability.

5
6 A further note. PJM seems to want to build a transmission system capable of delivering
7 every MW from any generator anywhere on the system to any load point in PJM –
8 regardless of reliability need or system conditions at the time. But that's not necessary
9 for a reliable, or even an economically optimum system. On a reliability basis,
10 comparable plans or options would include sufficient transmission capability to maintain
11 an appropriate Loss of Load Expectation overall.

12
13 PJM could use Loss of Load Expectation techniques to compare generating capacity and
14 other resources sited close to the load vs. less expensive generation more remote from the
15 load, including the constraints of the intervening transmission system. Economic
16 analyses would consider combinations of greater or lesser percentages of remote and
17 local generation. However, the cost of necessary new transmission, plus incremental
18 system losses, should be included. These costs would, of course, be much higher for
19 remote generation, which would tend to offset any economic advantage it might
20 otherwise have. Yet neither the applicants nor PJM has conducted any such analysis.

21
22 Q. IS PATH, IN YOUR OPINION, REALLY ABOUT RELIABILITY?

1 A. No. PATH is more about economics than reliability. When added to the present
2 import capability in excess of 6,000MW, there is more than enough generating capacity
3 within the constrained Mid-Atlantic LDA to supply all the load all the time. Thus there is
4 no reliability need to increase the import capability by about 2,000MW – from 6,240MW
5 to 8,190MW. This would involve operating more expensive, local generation more
6 frequently; however, reliability would be enhanced, since the Mid-Atlantic LDA would
7 be less dependent on generating capacity hundreds of miles away. Such an approach is
8 called “transmission constrained dispatch,” or the use of “out of merit” generation, and is
9 consistent with how the system is actually operated. It’s commonly used by most power
10 systems in North America in both planning and operations. It would reduce the chance of
11 widespread interruption, whether from human error, equipment failure, *force majeure*, or
12 terrorist attack. Any increase in generation costs would be offset by savings in
13 transmission construction, at least in part. Finally, and perhaps most important, this case
14 is supposed to be about *reliability*, not *economics*.

15
16 In my opinion, PATH isn’t just about economics *in general* – it’s about *coal-fired*
17 economics. This is clearly illustrated by a presentation made by Mr. Karl Pfirrmann at a
18 FERC Technical conference on May 13, 2005. At the time, he served as President, PJM
19 Interconnection, L.L.C., Western Region. In his Executive Summary, Mr. Pfirrmann
20 describes “the potential for new transmission resources in the region to enhance
21 opportunities for coal based generation to reach eastern markets.” The proposal is called
22 Project Mountaineer, and includes “potentially 550 to 900 miles of new backbone 500 or
23 765 kV transmission at an approximate cost of \$3.3 to \$3.9 billion.” In his written

1 comments, Pfirrmann describes this as a “new initiative ... to utilize our regional
2 transmission planning process to explore ways to further develop an efficient
3 *transmission ‘super-highway’ to bring low cost coal resources to market.*” [Emphasis
4 added.] Mr. Pfirrmann also hails “dramatic increases in the amount of power flowing
5 from this region into ‘classic’ PJM, including from coal-based generation,” and offers an
6 exhibit illustrating a 35-40% increase since PJM’s expansion to the west.

7
8 We can gain some perspective on this by considering PATH’s predecessor. An EHV line
9 from Amos to eastern PJM was proposed before any “violations” had been indicated.
10 This was in connection with Project Mountaineer, as discussed above. As suggested by
11 Mr. Pfirrmann, Project Mountaineer’s original goal was to provide access to eastern
12 markets for an additional 5,000MW of western generation. The TrAIL and PATH
13 projects, taken together, are remarkably consistent with such an intent. Some might ask,
14 if PATH is approved, what will be next?

15
16 Q. WHAT IS YOUR VIEW OF THE VOLTAGE STABILITY PROBLEMS CITED
17 BY MR. McGLYNN?

18
19 A. PJM has not proven that the alleged “voltage instability” is a legitimate problem. Mr.
20 McGlynn goes to considerable length to establish voltage instability, but his only
21 evidence – so-called “knee-of-the-curve” analyses – is incomplete. No transient stability
22 results have been shown. “Knee-of-the-curve” analysis is useful as a screening tool, but
23 voltage instability can only be proven by rotor-angle stability analysis in which the

1 dynamic response of the overall system to a sudden disturbance is simulated in the time
2 domain. Neither the applicants nor PJM have presented any such stability results. And
3 all of the cited violations occur at CETO values that I consider to be unnecessarily high.
4 Mr. McGlynn's testimony confirms that there are no voltage issues until transfers into the
5 Mid-Atlantic LDA are well above 6,000MW.

6

7 Q. WHAT ABOUT STEADY STATE VOLTAGES, BOTH ABSOLUTE VOLTAGES
8 AND VOLTAGE DROP?

9

10 A. Whatever voltage problems may exist might be solved by power factor correction.
11 Low voltage problems, whether on an absolute or a voltage drop basis, are generally an
12 indication that reactive (MVAR) loads are too high relative to active (MW) loads. This is
13 reflected by low power factors – i.e. the ratio of MW to MVA. Reactive (MVAR) load is
14 a natural part of power system load, and comes from various apparatus on customers'
15 premises. It can be reduced by the installation of shunt capacitors or static VAR
16 compensators (SVCs), which supply reactive power. Failure to adequately compensate
17 for reactive load means higher MVAR loads as seen from 115kV and 138kV substations,
18 hence lower power factors. Basically, what happens is that the high reactive loads have
19 to be supplied from remote generators and the EHV system, essentially dragging MVARs
20 through all the impedances of the various transmission lines and transformers. This
21 results in larger voltage drops. [A close approximation of voltage drop can be
22 determined by multiplying the per-unit inductive reactance of a line or transformer times
23 the per-unit MVAR flow through it.] Further, the higher power flows through all the

1 lines and transformers will result in higher reactive (MVAR) I^2X losses, and the
2 consequent need to pull even more reactive power off the EHV system, which leads to
3 larger voltage drops, etc. This phenomenon will only get worse as load grows. The best
4 place to correct power factor is to place shunt capacitors on the subtransmission and
5 distribution system – as close to the load as possible.

6
7 Many of the Mid-Atlantic buses listed in PATH's response to SierraVA-IV-51 have
8 power factors below 95% – despite the fact that PJM Manual 14B, Appendix D: "PJM
9 Reliability Planning Criteria" calls for a minimum power factors of 97%.

10
11 Power factor correction is in essence a reduction in reactive (MVAR) load, generally by
12 adding shunt capacitors on the distribution and/or subtransmission systems. If this is
13 impractical for some reason, shunt capacitors can be added at 115 and 138kV substation.
14 If for any reason even *that* is impractical, the applicants themselves have suggested the
15 solution – shunt capacitor or SVC additions at higher voltage stations.

16
17 Power factor correction (reactive compensation) is an ongoing process – it has to be
18 continued year after year as system load grows. It's part of the continuing obligation of
19 providing good utility service. The applicants do not seem to have examined if the
20 voltage problems could be fixed by improving power factors. Nor have they examined
21 the possibility of adding switchable shunt capacitors to some of the 115/138kV
22 substations. We have been told that a "high level" investigation was made which
23 considered adding shunt capacitors at 500kV and 230kV substations without PATH, and

1 this was deemed to be too expensive. But applicants' witnesses in other states have
2 testified that more than 1700MVAR of shunt capacitance will be required at both
3 terminals of the proposed PATH line! (See Dr. Hyde Merrill's testimony.) In any case,
4 no description of the nature of this "high level" investigation was provided. Without a
5 presentation of the results of power factor and lower voltage substation studies, and an
6 explanation of the reactive additions needed by PATH itself, the alleged voltage
7 problems cannot be proven.

8
9 Q. PLEASE DESCRIBE SOME OF YOUR OVERALL IMPRESSIONS OF THIS
10 CASE.

11
12 A. PJM and the applicants demonstrate a distinctly "one track mind" in their planning.
13 Alternatives involving means other than an AC EHV transmission line have not been
14 explored – this is true despite the fact that the problems discovered in the 2009 analyses
15 depict dramatically different limiting facilities than those uncovered in 2008. In fact, the
16 2009 "re-tool" cases came up with a very different set of problems, were less severe, and
17 occurred further out in the future. To most planning engineers, this would suggest that
18 other possible solutions should be examined, but no such attempt has been made. This is
19 especially true if the conclusions are the result of extrapolation. The original PATH
20 proposal remains unchanged, and alternatives remain unexamined.

21
22 There's a built-in bias against any other approach; e.g. the way representation of new
23 generators is handled strongly discourages serious consideration of non-transmission

1 alternatives. Even in the area of transmission itself, no alternatives other than 500 and
2 765kV AC have been examined. A strong case can be made that no additional
3 transmission is needed. But even if additional transmission *is* needed, why hasn't PJM
4 considered building PATH as, for example, an HVDC line? Or why hasn't the
5 conversion of an existing AC line (such as the Mt. Storm-Doubs 500kV line, as suggested
6 by Mr. Merrill) been considered?

7
8 As pointed out by my colleague, Dr. Hyde Merrill, all conclusions beyond the study year
9 of 2014 were based on extrapolation from 2014 results. It's almost inconceivable to me
10 that the need for a major transmission facility, costing in the neighborhood of \$2 billion,
11 would be based on extrapolated results. Extrapolation is also inconsistent with NERC's
12 requirements for long-term studies. As I indicated earlier, the purpose of long-term
13 studies is to provide some indication of the nature and direction of future reliability
14 problems, and to ensure that any recommended short-term solutions will be consistent
15 with future needs. Extrapolation does not, in my view, satisfy that requirement.

16 AEP and its partners seem to have refused to "think outside the box." Perhaps PATH's
17 emphasis on AC EHV transmission, and the effective subsidization of western
18 generation, reflects the potential profits that could be made from transmission usage
19 charges, as well as AEP's ownership of major significant western generating resources.

20 A major facility like the PATH line should not be approved based on extrapolation.

21
22 To summarize:

1 • In my opinion, there's a major problem with PJM's present RTEP/CETO process of
2 assessing reliability. The assumptions are too conservative, and lead to requirements
3 beyond what would be needed for good reliability.

4
5 • PATH would discriminate against eastern generation and other potential resources, and
6 promote western generation, by providing the latter with free access to eastern load
7 centers – all at the expense of the rate-payers.

8
9 • Whereas the rest of the industry utilizes a loss of load expectation of one day in 10
10 years, PJM uses one day in 25 years to determine the import capability required by each
11 Load Deliverability Area (LDA) – which can be quite large. The Mid-Atlantic LDA, for
12 example, has a peak load in excess of 60,000MW. This makes it equal in size to the
13 combined neighboring New York and New England ISOs. Assumptions more in line
14 with the industry, rationalized to a reliability standard equivalent to that used by New
15 York and New England, would result in a CETO which would be lower than the point at
16 which the first reliability violations occur. In other words, there would be no NERC
17 violations.

18
19 • Without this overly conservative approach, CETO values would be lower and there
20 would be no NERC violations. Hence there is no demonstrated need for PATH.

21
22 • Reasonable alternatives, both non-transmission and even transmission, were not
23 considered despite their potential advantages in terms of cost, reliability, and

1 environmental impact. The applicants did not consider any reasonable alternatives based
2 on the currently identified (April 2009) issues.

3

4 • By increasing the dependence of the eastern load centers on remote generators and
5 transmission lines hundreds of miles long, PATH would actually lower reliability. This
6 is the *real* reliability problem in PJM. Further, the increased reliance on very long
7 transmission lines is a national security issue.

8

9 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

10

11 A. Yes.



MISO IMM Comments on LRTP Tranche 2 Benefit Metrics

MISO Independent Market Monitor

David Patton, Ph.D.
Potomac Economics

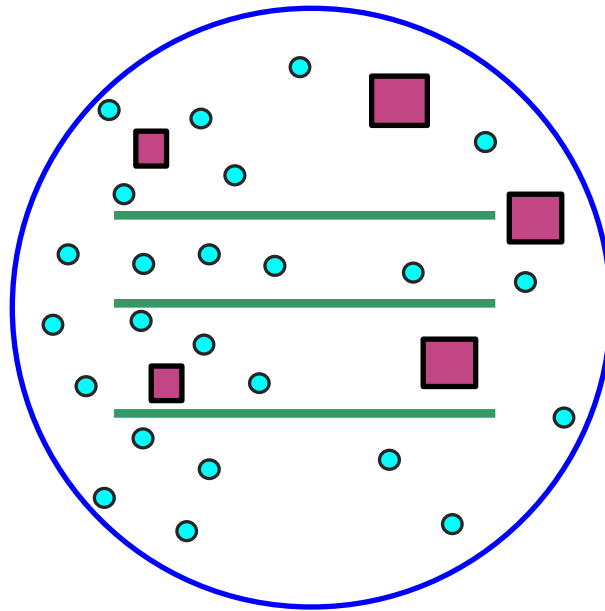
May 29, 2024

Comments on Analysis of Transmission Benefits

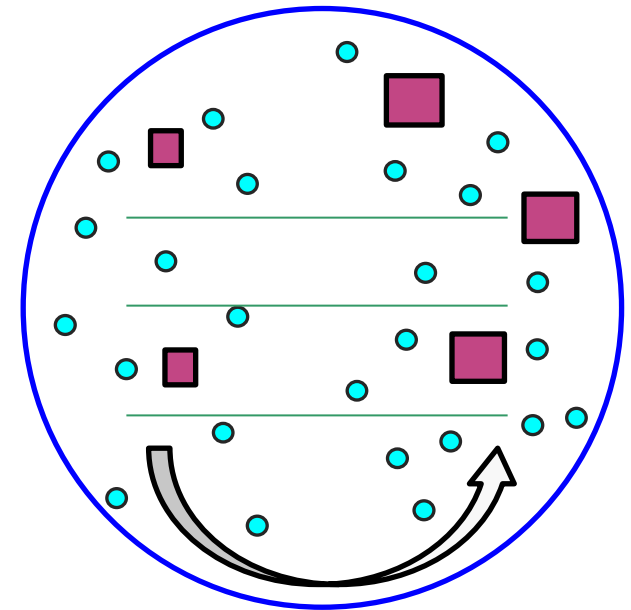
- Transmission investment will be a critical component of MISO's evolution over the next 20 years.
- It is important that this investment be economic –
 - ✓ Uneconomic investment will raise costs and undermine investment in resources, storage and other alternatives to transmission.
 - ✓ We have previously expressed concerns about the unrealistic nature of Future 2A growth assumptions.
 - ✓ MISO has chosen not to attempt manual optimization (evaluating alternative siting impacts on individual projects or to resolve overloads).
 - ✓ The benefits methodologies are likely to lead to substantially over-estimated benefits, which we describe in this presentation.
- One of our primary concerns is related to the fact that the effects of MISO's markets are not properly recognized as illustrated below.

Recognizing the Market Effects in the Benefit Analyses

With Tranche 2



Without Tranche 2



- One of MISO's main responsibilities is to operate markets that provide key economic signals to guide generation investment and retirement decisions.
- Benefit analyses must recognize that new transmission will change energy and capacity market signals – less transmission will shift resources closer to load.
- This will reduce or eliminate many of the benefits (e.g., capacity savings and reduced losses).

Classes of Transmission Benefits

- MISO has proposed 9 classes of transmission benefits.
- Classes that are likely to be valid and reasonable, depending on the details:
 - ✓ Congestion and fuel costs savings
 - ✓ Reduced transmission outage costs
- Classes for which we have significant or fundamental concerns:
 - ✓ Avoided capacity costs
 - ✓ Decarbonization
 - ✓ Mitigation of reliability issues
- Classes that are may be overestimated depending on the methodology
 - ✓ Capacity savings from reduced losses
 - ✓ Energy savings from reduced losses
 - ✓ Avoided transmission investments
 - ✓ Reduced risks from extreme weather events
- This presentation discusses our comments on each class of benefits.

Congestion and Fuel Costs Savings

- This class of benefits is the most valid and represents the truest measure of the economic benefits of transmission
- **Concerns:** Although it is the most valid, it depends heavily on the input used to ensure the savings are accurate. Some factors that would tend to reduce these benefits may not be included in MISO's methodology.
- **Recommendations:**
 - ✓ Develop a reference case that modifies siting assumptions to simulate market responses without Tranche 2. Siting would locate new additions inside of congested areas (closer to load, in capacity import limited areas, at raise help locations).
 - ✓ Include the effects of AARs on the existing network facilities.
 - ✓ Model the contribution of storage in reducing peak transmission flows and congestion since mitigating congestion is a significant component of the business case for storage.

Reduced Transmission Outage Costs

- **Comment:**
 - ✓ This benefit is a potentially valid class of benefits since the base production costs savings would not tend to include transmission outages that are experienced regularly.
 - ✓ However, the magnitude of this estimated benefit is highly uncertain.
- **Recommendation:**
 - ✓ MISO should adopt a conservative approach to estimating this benefit that reflects the historical effects of outages.

Avoided Capacity Cost

- **Concern:** There is little basis to assume that transmission will affect MISO's capacity requirements.
- The extent to which resources are deliverable *will* affect the amount of capacity needed, but the markets provide incentives to be deliverable.
- However, the MISO methodology:
 - a. Creates a base case with sufficient generation to meet 1-in-10 on a copper sheet, but the generation is not deliverable.
 - b. Adding in the network makes it appear that more capacity is needed to meet 1-in-10 since the assumed generation is not fully deliverable.
 - c. Tranche 2 makes the generation much more deliverable so capacity needs are lower than in (b).
- This is not a valid benefit because, absent the transmission, markets will motivate/require generation in deliverable locations closer to load.
- **Recommendation:** i. Eliminate this benefit or ii. Develop alternative case with modified siting assumptions and calculate cost of *moving* resources.

Decarbonization

- **Concern:** The congestion and fuel savings include the PTC values, which fully reflects the value of decarbonization, so calculating an additional benefit is double counting.
 - ✓ The PTC is the most reasonable benchmark for the value of carbon since it is law and represents what the government will actually pay.
 - ✓ The PTC corresponds to a carbon value of ~\$50/ton. The Biden administration's value of carbon is \$51/ton, which is being litigated.
 - ✓ EPA has proposed almost a 4-fold increase, almost all of which is based on lowering the discount rate from 3% to 2% percent based on falling interest rates up to 2021. Rates have been rising since then to > 4%.
 - ✓ MISO has no basis to impose a cost higher than the PTC on its customers when there is no consensus that the PTC undervalues carbon.
- **Recommendation:** Eliminate this benefit class as it is already captured in the production cost savings.

Mitigation of Reliability Issues

- **Concerns:**

- ✓ Quantifying this benefit by assuming MISO will shed load to address voltage or other issues (without Tranche 2) is not realistic.
- ✓ In reality, these issues are addressed by thermal proxies, reconfigurations, or by investments in other equipment that would be much less expensive than load shedding.

- **Recommendation:**

- ✓ Eliminate this class of benefits; or
- ✓ Quantify cost based on the next operating action to address the issues if transmission is not built (not load shedding):
 - Congestion from modeling a thermal proxy; or
 - The costs of equipment to address the issues (e.g., voltage support).

Capacity and Energy Savings from Reduced Losses

- **Concern:**

- ✓ In principle we agree that new higher voltage transmission will reduce losses;
- ✓ BUT, the loss reductions should reflect the fact that resources will relocate closer to load without the Tranche 2 projects.

- **Recommendations:**

- ✓ Develop alternative reference case that modifies siting assumptions to reflect market responses without the portfolio.
- ✓ Siting would locate new additions closer to load, in capacity import limited areas, and at raise help locations.

Avoided Transmission Investment

- **Concerns:**

- ✓ Avoided transmission maintenance/replacement could be a valid benefit.
- ✓ Avoided transmission investment that is hypothetically needed to address congestion would be inappropriate unless:
 - Avoided benefits are quantified and deducted from the avoided capital costs.

- **Recommendation:**

- ✓ Include only maintenance/replacement projects (age and condition) that would be avoided.

Reduced Risks from Extreme Weather Events

- **Concern:**

- ✓ This is one of the most uncertain and speculative benefits.
- ✓ Each of the extreme weather events have resulted in extremely different patterns of flows so it is difficult to predict how transmission would help.
- ✓ The benefits should be small because the probability of extreme weather events are low.

- **Recommendation:**

- ✓ MISO should ensure that it does not implicitly increase the probability of extreme weather events in calculating the benefits.
- ✓ $\text{Benefit} = \text{Potential Savings during Event} * \text{Probability of Event}$.

Other Comments on Benefit Estimates

- We have additional recommendations to improve the benefit estimates.
- Divide the portfolio into groupings of projects that address separate issues to validate that each grouping passes a benefit-cost test.
 - ✓ Assessing the entire portfolio together would not allow MISO to pair it down so that it only includes the economic groupings.
- Adopt a sensitivity case similar to IMM-2A, which has more dispatchable/storage/hybrid resources than MISO's Future 1A.
 - ✓ Although Future 1A has substantially less intermittent renewables, it also understates the likely quantity of dispatchable resources that are key for managing congestion.
- Consider improving a) the siting of resources based on the location of congestion, and b) the modeling of battery storage to resolve congestion.
 - ✓ MISO should examine whether the congestion identified in reference case can be more economically be managed with storage to verify the robustness of the business case.

In urging the Commission to reject the results of that “long, rigorous, and iterative”⁷¹ process, the parties to the Stipulation are asking the Commission to undermine public confidence in its integrity. Xcel had wanted to build two new combustion turbines, but agreed to postpone a determination on their approval after the process demonstrated that they weren’t yet necessary and intervenors were concerned about their cost and environmental impacts.⁷² Instead, the Commission found that “it is more likely than not that there will be a need for approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029.”⁷³ Because Xcel “systematically overestimates demand and underestimates costs,”⁷⁴ the Commission reiterated multiple times in its order that 800 MW was the maximum capacity that could be acquired pursuant to that IRP order.⁷⁵ Accepting the Stipulation would require the Commission to reject its own unambiguous order, which was informed by significant public input, in the name of expediency.

Xcel argues that the Commission’s language does not mean what it says, first quoting the Commission’s “not more than 800 MW” and immediately stating that this somehow meant “more or less than 800 MW.”⁷⁶ To be clear, the Commission stated three separate times that 800 MW was the maximum firm dispatchable capacity to be acquired in its 2022 IRP order.⁷⁷ The Commission then reiterated this in its order authorizing the instant bidding process one year ago,

Compliance Filing, and Setting Requirements for 1995 Resource Plan Filing at 2-3 (Jul. 15, 1994); 2006 RFP Order at 2.

⁷¹ 2022 IRP Order at 12.

⁷² *Id.*; Docket No. E-002/RP-19-368, Supplemental Comments of the Clean Energy Organizations at 12-30 (Oct. 15, 2021); *see also* Docket No. E-002/RP-19-368, Public Comment of Institute for Local Self-Reliance et al. (Oct. 15, 2021).

⁷³ 2022 IRP Order at 32.

⁷⁴ *Id.* at 11; Docket No. E-002/RP-19-368, Supplemental Comments of the Department of Commerce at 9 (Oct. 15, 2021).

⁷⁵ 2022 IRP Order at 14, 32.

⁷⁶ Xcel Comments in Support of Stipulation at 22.

⁷⁷ 2022 IRP Order at 14, 32.

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One alternative will consider the implications of using biomass gasification at the third boiler. Gasification may prove to be a superior technology because of its low emissions, relative cost, and suitability for the specific type of cyclone boiler at Bay Front, which cannot effectively burn chipped or shredded wood. If the study demonstrates that biomass gasification is a viable option and the Company converts the plant, Bay Front would become one of the largest biomass-fueled plants in North America. We expect to complete our studies in late 2008, and if feasible, a filing to the Commission describing the findings and recommendations will be made at that time.

Red Wing and Wilmarth Plants

Both plants are located south of the Twin Cities area. The Red Wing plant is located in Red Wing, Minnesota and the Wilmarth plant in Mankato, Minnesota. Both plants have two 10 MW generating units and burn processed municipal solid waste, called refuse-derived fuel (“RDF”).

Both plants were built in the 1940s as coal-fired generating facilities. They were both converted in the late 1980’s to burn RDF. The processed municipal solid waste provides a low-cost fuel alternative to generate electricity and reduces the amount of material going to landfills. Both plants employ scrubbers with fabric filter baghouses to meet their respective emissions permits. The scrubbers treat flue gas with water and hydrated lime, while the baghouses trap particulate by forcing flue gas streams through large filter bags. These systems are considered to be best available control technology (“BACT”), which allows energy production from Red Wing and Wilmarth to be counted toward the RES.

The RDF for both plants is produced at resource recovery facilities in Newport and Elk River, Minnesota. The fuel supply contract for Red Wing and Wilmarth runs through 2012 as does the book life of these facilities. For capacity planning and RES compliance planning purposes, we are assuming

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that Red Wing and Wilmarth will be retired at the end of 2012. During the intervening years, we will work to renegotiate fuel supply arrangements and evaluate whether to refurbish these facilities after 2012, or retire them. Such decisions will depend on whether a new fuel supply contract proves to be reliable and cost-effective as well as evaluating the condition of plant equipment. We anticipate providing the Commission with an update on plans for Red Wing and Wilmarth in our next Minnesota Resource Plan filing, presumably in 2009 or 2010.

French Island Generating Plant

The French Island Generating Plant is located in LaCrosse, Wisconsin, on the Mississippi and Black rivers. Units 1 and 2 burn wood waste, railroad ties and RDF. Units 1 and 2 combined produce 25 MW. Units 3 and 4 are 1970s-vintage oil-fired combustion turbines. These units each have the capability of producing 72 MW (summer) and 100 MW (winter). The plant was built in the 1940s as a coal-fired generating facility with Units 3 and 4 converted in 1972 to burn oil, a cleaner fuel. However, within two years after the conversion, the oil embargo caused oil prices to significantly increase, and the units were fired less frequently because they had become expensive to operate.

By the early 1980s, we identified a new low-cost fuel in waste wood, and converted Unit 2 to a fluidized bed boiler to burn it. In addition to reducing operating costs, burning wood helped solve a waste disposal problem by using sawdust and wood chips that otherwise would have been buried in a landfill. For similar reasons, in 1987, the Company built a facility adjacent to the generating plant to process municipal solid waste into RDF. The necessary fuel handling modifications were made to the plant and Unit 1 also was converted to a fluidized bed boiler, making both units capable of burning a blend of waste wood and RDF. The conversion helped extend the life of the plant and maintain reasonable electric rates for customers, while resolving a solid waste disposal problem for La Crosse County.