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February 21, 2024

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

RE: No CapX 2020 EIS Scoping Comment & Exhibits
MN Energy CON - Lyon Co. to Sherco Transmission Line
PUC Dockets E001/CN-22-131 and E001/TL-22-132

Dear Mr. Seuffert:

I'm filing these comments on behalf of NoCapX 2020, an intervenor and participant in three of the CapX 2020 dockets in concert with local grassroots groups. I've attached comments filed previously in this docket as well.

<u>EIS must document and consider cumulative impacts of MN Energy CON on top of CapX 2020</u>

At the MN Energy CON road show meetings of January 24-25 and 30-31, I was shocked at the number of people who were already paying the price of CapX 2020 routed on their property and who were very upset at the prospect of having more land taken for this project, in some cases, even two separate paths through their land. In at least one, and I believe two who spoke, they'd be surrounded on three sides with transmission. The EIS should address the cumulative impacts of the threat of having another transmission line on property that already has one easement, and the impact if it is ultimately routed on land with an existing easement. The people who testified, and those I spoke with directly, range from being disheartened, and believe it's hopeless, that they cannot have an effect on the outcome, or they're very, VERY, angry that the company dare propose more transmission, or somewhere in that continuum. Those in the MN Energy CON's path are likely experiencing stress, inertia, they're overwhelmed, fearful, and thwarted in their very existence.

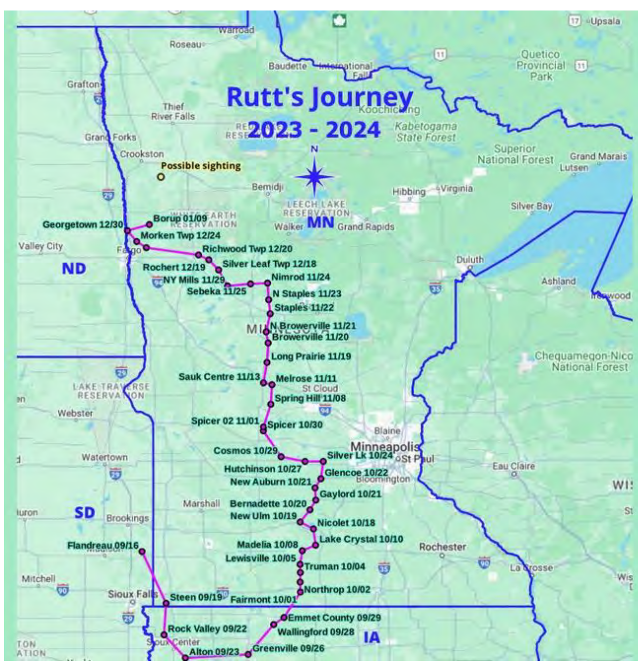
It's not a matter of "what's one more line." The impact of "one line" should not be dismissed or minimized. The EIS should take into account that one more transmission line is an extreme affront to those who have been through the agonizing process of giving up their land for CapX 2020 or any other transmission line. If they went through the CapX 2020 routing process, they experienced a time consuming and exhaustive excursion through the Public Utilities Commission's process, and with any luck, their land was avoided. If not, and "their" route was selected, in addition to the Commission's process, they've had to negotiate an easement or slog through an eminent domain proceeding, deal with construction and the long term impacts, and then to be confronted again… from the testimony in these meetings, they're feeling unfairly targeted. Both the uncertain specter of transmission with plans, with life, on hold for the duration; or after participation through the process, the selection of someone's land, are extreme impacts. Although these impacts may not be quantifiable, they're inherent in this process, and must be given great weight.

<u>EIS must document and consider impacts of the threat of transmission to landowners</u>

Similarly, for those confronted with their "first" transmission line, they need to learn to navigate the process, attend meetings, speak up, compose comments, giving their best to explain what this project would mean to them, would do to them, how it would affect their lives, their land, and raise all the impacts that would befall them and all in their environment. It's a big job, and few can comfortably participate in this process. The EIS should address the impacts extreme burdens on landowners going through this process.

<u>EIS must consider impacts on wildlife</u>

The EIS must consider the impacts of wildlife. An atypical impact not likely considered previously is that of resident and migrating wildlife, such as Rutt, the "Moose on the Loose" migrating across the area of this transmission line route.



Similarly, another atypical impact would be on resident or migrating elk. An elk was sighted in Lyon County.[1] Animals in the Cervidae family are particularly sensitive to, and avoid, ultra violet frequencies.

Other cumulative environmental factors raised by commenters at public meetings

The EIS must also document and consider the socioeconomic impacts on communities, as transmission also applies to communities with CapX in their viewsheds, too near homes, barns, interfering with agricultural practices such as aerial spraying.

Magnetic fields are grossly understated

THE EIS MUST INCLUDE MAGNETIC FIELD MODELING FOR MVA UP TO THE 3,584 MVA OF THE PROJECT AS DESIGNED.

The magnetic field calculations are based on only on 660 and 1100 MVA in Xcel's Revised Application, downplaying the modeled magnetic field levels at the right-of-way edge:

Table 6.2: Magnetic Field Calculation Summary

Structure Type	System Condition	Current (Amps)	Distance to Proposed Centerline (feet)												
			-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV/345 kV Double-Circuit Monopole	Peak System Energy Demand (1100MVA/1100MVA)	1850/1850	1.5	4.5	25	45	90	161	237	167	95	45	24	3.5	1
	Average System Energy Demand (660 MVA/660 MVA)	1100/1100	1	2.6	15	27	54	96	141	99	56	27	14	2	0.6

At each of the 75 foot edge of the 150 foot right of way, the magnetic field is projected to be 27 mG if 660 MVA and 45 mG if 1,100MVA. If modeled at the line's rating, 1,792 MVA per circuit, 3,584 MVA total, would the mG at the edge of the right of way be three times that 45, or 135 mG?

Compare with the NIEHS EMF RAPID study and the WHO studies, recommending a mG level of 2-4 mG. And the ICNIRP guidelines should be addressed:

The International Commission on Non-Ionizing Radiation Protection (ICNIRP) concluded that available data regarding potential long-term effects, such as increased risk of cancer, are insufficient to provide a basis for setting exposure restrictions.

The American Conference of Governmental Industrial Hygienists (ACGIH) publishes "Threshold Limit Values" (TLVs) for various physical agents. The TLVs for 60-Hz EMF shown in the table are identified as guides to control exposure; they are not intended to demarcate safe and dangerous levels.

ICNIRP Guidelines for EMF Exposure

Exposure (60 Hz)	Electric field	Magnetic field
Occupational	8.3 kV/m	4.2 G (4,200 mG)
General Public	4.2 kV/m	0.833 G (833 mG)

International Commission on Non-Ionizing Radiation Protection (ICNIRP) is an organization of 15,000 scientists from 40 nations who specialize in radiation protection.
Source: ICNIRP, 1998.

ACGIH Occupational Threshold Limit Values for 60-Hz EMF

	Electric field	Magnetic field
Occupational exposure should not exceed	25 kV/m	10 G (10,000 mG)
Prudence dictates the use of protective clothing above	15 kV/m	–
Exposure of workers with cardiac pacemakers should not exceed	1 kV/m	1 G (1,000 mG)

American Conference of Governmental Industrial Hygienists (ACGIH) is a professional organization that facilitates the exchange of technical information about worker health protection. It is not a government regulatory agency.
Source: ACGIH, 2001. [2]

[1] Rare elk sighting in Lyon County captured on game cameras from southwestern Minnesota: https://www.outdoornews.com/2023/11/22/rare-elk-sighting-in-lyon-county-captured-on-game-cameras-from-southwestern-minnesota/

[2] Table from *Electric and Magnetic Fields Associated with the Use of Electric Power,* online at: https://www.niehs.nih.gov/sites/default/files/health/materials/electric_and_magnetic_fields_associated_with_the_us

While causation has not yet been demonstrated, association has.

In the several CapX 2020 proceedings, the magnetic field modeling was consistently understating the magnetic fields. See attached Affidavit of Bruce McKay, PUC Docket TL-08-1474.

The EIS must address the projected high levels of magnetic fields at the right of way edge and various distances from the centerline, and the EIS must address the potential for extreme levels of magnetic fields if the transmission line is operated at higher MVA than disclosed.

NEED – SIZE, TYPE, & TIMING - adding to comment file January 24, 2024

At the public hearings, it was repeatedly stated that the EIS will address matters of need, and specifically "size, type, and timing" and the "no-action alternative." Xcel did receive exemptions from certain "**application** data requirements" in a consent Order of June 28, 2022:

> **2. Approved the following exemptions from the certificate of need application data requirements conditioned on Xcel Energy providing alternative data:**
>
> **a. 7849.0260, subp. A (3) and C (6)—granted the requested exemption with the provision of the proposed alternative data;**
>
> **b. 7849.0260, subp. B (4) and B (8)—granted the requested exemption;**
>
> **c. 7849.0270—granted the requested exemption with the provision of the proposed alternative data and require Xcel to provide updated demand and energy forecasting data;**
>
> **d. 7849.0280, subp. B through I—granted the requested exemption with the provision of the proposed alternative data and required Xcel to state any updates to the quantity of new generation needed based upon the updated demand and energy forecasting provided under Minnesota Rules 7849.0270;**
>
> **e. 7849.0290, subp. F—granted the proposed exemption and required Xcel to present a summary of the conservation information in the IRP and CIP filings rather than replicate the data in the instant docket;**
>
> **f. 7849.0300 and 7849.0340—granted the requested exemption with the provision of the proposed alternative data; and**
>
> **g. 7849.0330, subp. G—granted the requested exemption with the provision of the proposed alternative data.**

Order, June 28, 2022. While the Commission has exempted Xcel from providing that data itemized above from 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 and is requested.

In considering "need," there are specifics for the Commission, that **NO PROPOSED LARGE ENERGY FACILITY SHALL BE CERTIFIED**…" The statutory Certificate of Need requirements can be found in Minn. Stat.§ 216B.243, of which each and all of them have environmental components and this showing necessary for a Certificate of Need goes beyond that which is required for an application.

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> **Subd. 3.Showing required for construction.**
>
> No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:

Minn. Stat.§ 216B.243, Subd. 3.

<u>SIZE OF PROJECT IS FAR BEYOND CLAIMED NEED</u>

There are two aspects of size that should be addressed in this EIS. The first is that the project as designed is grossly oversized at 3,583 MVA for the claimed "need" of 1,996MW.

At the January 25, 2024 Scoping meeting, Xcel engineer Jason Standing admitted that each of the circuits, comprised of twisted and then bundled conductors had a capacity rating of 1,792 MVA, and as a double circuit, double that, 3,583 MVA.. MVA and MW are essentially equal, and Mr. Standing should explain this for the record.

If the "need" is for 1,996 MW to interconnect, which is all Xcel has interconnection rights for, why build a project capable of 3,583 MVA? This is 1,795 more than what's "needed."

The application also states that the project could enable up to 4,o00 MW of generation!

Where the size is all out of proportion to what is claimed to be "needed," there is insufficient justification for the project as proposed.

<u>SIZE OF PROJECT MEANS THAT HUNDREDS OF MW MUST BE BUILT TO MAKE UP FOR LINE LOSS</u>

The second aspect is that due to line losses, at least 200 MW of additional generation will have to be built to make up for the line loss of this project, admitted to be at least 204MW for the 1,996 MW to be received at the Sherco point of interconnection.

The first of the Commission's exemptions provides that Xcel need not disclose line losses in its application. However, the Commission did require "alternative data" in its Order of June 2 In the Commission's Order of August 10, 2023, the commission admitted, after interconnection of 2,200 MW, line losses of approximately 204MW, to result in 1,996 delivered to the Sherco substation:

> 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.

Whether 160-180, losses would be 11.75% to 12.33%.

For the 3,583 MVA, line losses would be approximately 370MW. That gives a range of 204 to

370MW depending on line loading. That's two to almost four times the largest solar project, at 100MW, now operating in Minnesota.

THE EIS MUST CONSIDER THE INEFFICIENCIES OF TRANSMISSION AND THE ENVIRONMENTAL IMPACTS OF THE CONSTRUCTION AND OPERATION OF GENERATION NECESSARY TO MAKE UP THE 204-370MW OF LINE LOSS, AND MUST EVALUATE FOR ALL TYPES OF ALTERNATIVES, FROM SOLAR TO WIND TO STORAGE TO MINDFUL SITING OF DISTRIBUTED GENERATION.

The EIS must address the impacts of construction of generation to make up the line losses of this project. Line losses were a significant part of Xcel's determination of which of its alternatives would be proposed[3]. Line losses were also significant in Xcel's choice of Option 9 for this project:

Option	Voltage	Lines	Bifurcated	Line 1					Line 2					Total Wind Nameplate Gen (MW)	Line Losses (MW)	Total POI Gen (MW)
				Line Comp	STATCOM Size (MVAR)	Intermediate Sub (MW)	Terminal Sub (MW)	Terminal Sub Synch Cond.	Line Comp	STATCOM Size (MVAR)	Intermediate Sub (MW)	Terminal Sub (MW)	Terminal Sub Synch Cond.			
1	345	1	---	---	---	200	500	---	---	---	---	---	---	700	37	663
2	345	1	---	49%	---	200	900	---	---	---	---	---	---	1100	74	1026
3	345	1	---	49%	---	200	1200	2	---	---	---	---	---	1400	118	1282
4	345	2	Y	---	---	200	1000	---	---	---	---	---	---	1200	59	1141
5	345	2	Y	---	---	200	1400	2	---	---	---	---	---	1600	100	1500
6	345	2	---	---	---	200	400	---	---	---	200	400	---	1200	58	1142
7	345	2	---	49%	---	200	700	---	49%	---	200	700	---	1800	107	1693
8	345	2	---	49%	---	200	1200	2	49%	---	200	700	---	2300	172	2128
9	345	2	---	49%	---	200	1100	1	49%	---	200	1100	1	2600	204	2396
9a	345	2	---	20%	1x150	200	1000	1	20%	1x150	200	1000	1	2400	218	2182
9b	345	2	---	---	2x175	200	900	1	---	2x175	200	900	1	2200	173	2027
10	500	1	---	49%	---	200	1700	2	---	---	---	---	---	1900	137	1763

Revised Application, Table 5.2, p. 65. Voltage support was necessary due to line losses:

> **Two voltage support alternatives** were analyzed as part of Option 9, Option 9a and 9b, which both achieved 1,996 MW at the POI. These alternatives could be utilized if turbine type, size, and location cause the need for series compensation to be decreased to achieve necessary system performance. These two options **include a combination of low levels of series compensation and STATCOMs to achieve a minimum of 1,996 MW at the Sherco POI.**

Attached is a copy of the Commission's August 10, 2023 Order Authorizing Joint Procedures in this Certificate of Need docket. This Order sets out a very important fact: that 2,200 MW of generation would deliver "approximately 1,996 MW to the Sherco Substation." In this Order,

[33] Let's not forget that the SW MN 345kV transmission line approval turned on line losses. See Docket 01-1958.

the Commission presumes "approximately" 204 MW line loss, if 160 miles, 12.75%, and if 180 miles, 11.33% is lost. I'm very grateful to see that at long last the Commission is recognizing, in an Order, the inherent inefficiencies of transmission over distance. The EIS must consider the impacts of line loss necessitating additional generation to make up for that percentage.

SIZE must also address the solar generation to be built adjacent to SHERCO

Linked below is a Strib article of September 21, 2023[4], "Minnesota regulators vote to move forward the third large Xcel solar project in Becker." This article notes the Commission's prior approval of "Sherco Solar 1 and 2" of 460 MW, and the approval of "Sherco 3" solar at 250 MW. The "Sherco 3" project compensates for the line loss of the Lyon Co. to Sherco line!

The 710 MW of these projects discussed in that article is over one third of the interconnection capacity of 1,996 MW that Xcel wants to preserve at that Sherco site. 1,996 less 710 is 1,286 MW remaining of transmission interconnection capacity for Xcel to find. Xcel has no justification for over 1,286MW, much less the 3,584MVA potential designed for this project.

SIZE, TYPE, AND TIMING – Xcel has excess capacity to market

The EIS must address the issues of size, type, and timing regarding Xcel's claim of need for generation, and whether that is credible, whether the impacts should be born by ratepayers landowners, and the public, when Xcel states in SEC filings that it is selling 1,500MW into the MISO market:

> ***MISO Capacity Credits*** — The NSP System offered 1,500 MW of excess capacity into the MISO planning resource auction for June 2022 through May 2023. Due to a projected overall capacity shortfall in the MISO region, the 1,500 MWs offered cleared the auction at maximum pricing and is expected to generate revenues of approximately $90 million in 2022 and approximately $60 million in 2023. During the three and nine months ended Sept. 30, 2022, the NSP System received approximately $40 million and $50 million, respectively, of capacity credits. These amounts will primarily be used to mitigate customer rate increases or returned through earnings sharing or other mechanisms.

Xcel 2022 3Q SEC filing, p. 32 of 46.[5]

TYPE – Desire to preserve interconnection rights is not "need"

The desire to preserve interconnection rights is not "need." Energy policy is not need. – Minn. Stat. §216B.243. The EIS must address the type of project and the environmental

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[4] Online at: https://www.startribune.com/minnesota-public-utilities-commission-votes-to-move-forward-third-large-xcel-solar-project-in-becker/600306452/

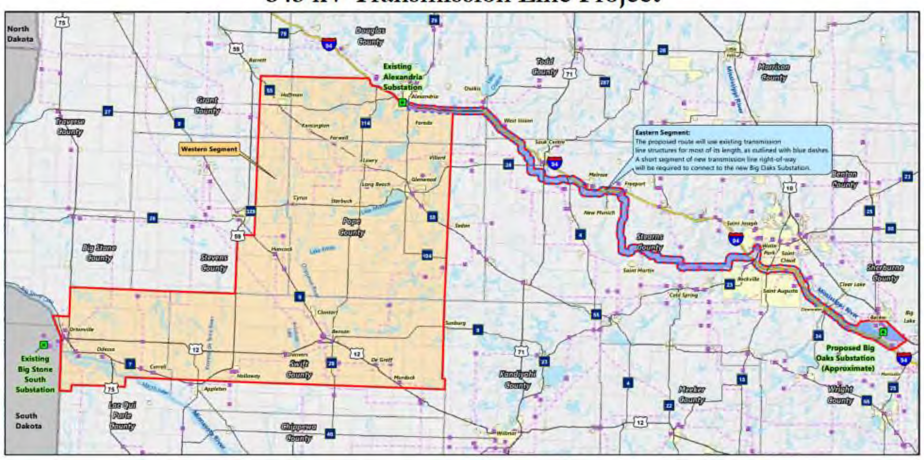
[5] Online at: https://d18rn0p25nwr6d.cloudfront.net/CIK-0000072903/206b8ecf-96d1-40a6-a8d4-681dec91da13.pdf
The 2023 10-K is expected to be released any minute…

impact posed by Xcel's project in relation to the desire to preserve interconnection rights. The EIS must address other ways of preservation, including but not limited to interconnection of the 710MW of solar in the area.

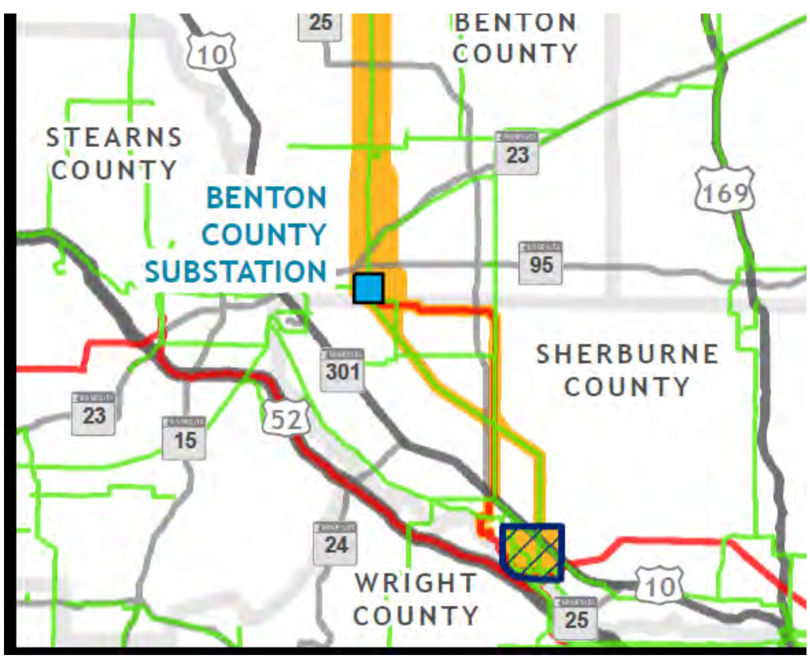
<u>TYPE & TIMING – Big Stone-Alexandria-Big Oaks would bring electricity to the Sherco area, as would the Northern Reliability Project</u>

The EIS must address the transmission line proposed from Big Stone to Alexandria to Big Oaks, essentially to the Sherco area. The Big Stone area is near Lyon County start of MN Energy CON. Why another? See PUC Docket E002, E017, ET2, E015, ET10/CN-22-538:

Figure 1: Big Stone South – Alexandria – Big Oaks
345 kV Transmission Line Project



The Northern Reliability Project, E015,ET2/CN-22-416 and E015,ET2/TL-22-415. runs from the Itasca County substation near Grand Rapids to the "Big Oaks" substation near Sherco:

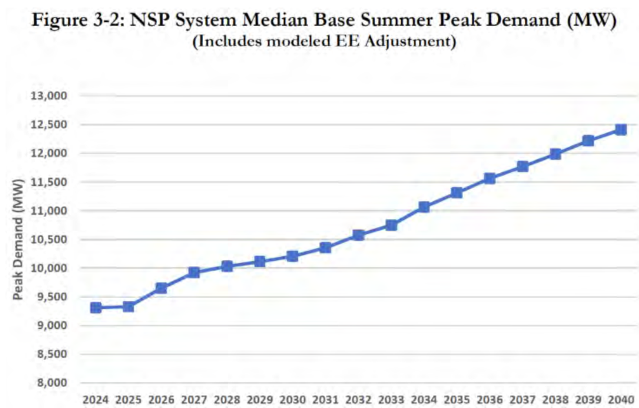


TIMING – Xcel has no "need" for additional generation

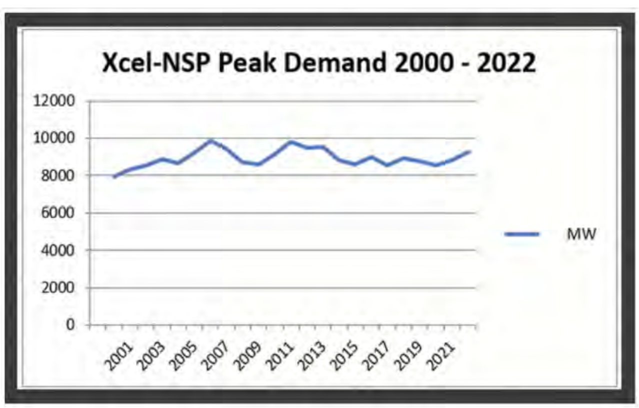
The EIS must critically examine Xcel's latest IRP claim of a marked and unexpected material increase in demand. This increase is too convenient to be believed, and must be balanced with the point of this project, which is to preserve interconnection rights.

In its application for the MN Energy CON transmission line is the admission of nominal increase in peak demand[6]. The EIS needs to examine which number is correct. Either way, this is a much more realistic projection than was used to justify CapX 2020, the absurd 2.49% of demand increase that at the time intervenors knew was a gross overstatement, and which obviously did not pan out. Peak demand has not yet met the 2006 peak.

The EIS must also address timing of Xcel's convenient claim of an annual 1.8% increase in peak demand, as of its just filed Integrated Resource Plan, PUC Docket RP-24-67. It contains a chart that is eerily reminiscent of the grossly overblown CapX 2020 demand projections, see IRP Chapter 3, page 2 of 29:



That IRP projection is laughable. Referring to their CapX peak demand projections as "grossly overblown" is not hyperbole. Here is their peak demand as taken from the Xcel Energy 10-K filings with the SEC:



[6] Note the application is inconsistent in its claim, first that peak demand is expected to increase at a rate of 0.2% into the 2030s, and later in the application, that number is -0.2%. Search the application for 0.2% and -0.2%!

As this docket moves forward, the Commission should also keep in mind that Xcel is selling 1,500MW of "excess capacity" on the market, energy not needed to serve its native load. This "excess capacity" should be considered in the calculation of need.

The EIS should consider whether the "need" is in line with the decrease in reserve margins. For decades we've been told that transmission build-out will decrease the necessary reserve margin, and that has at long last happened, or is admitted by Xcel. Typically, the MAPP, then MISO, reserve margin was set at 15%. The NERC Long-Range Transmission Reliability Assessment through the years has shown that with projected generation additions, there is far above that 15% of generation over and above area "need." The Commission should take into account the analysis of utility provided information when considering "need" for any project.

The EIS must include a cost benefit analysis of the project. This project has not been reviewed by MISO (utilites have become dependent, have relied on MISO to justify "need" for a project). In MISO cost/benefit determinations, the benefits are all to the utility/members of MISO. Similarly with this project, the benefits accrue to Xcel in preserving its "valuable transmission interconnection rights" and continued transmission service revenue, and the costs are falling to the ratepayers, to the projects lining up to interconnect, and to landowners who lose their land for easements. The EIS cost/benefit analysis must address the variety of costs and benefits to ratepayers, landowners, and the general public.

Alternatives – Geo Thermal, Distributed Generation, Storage, etc.

The EIS should consider alternatives that reduce the environmental impact of transmission by ELIMINATING need for much of it. An example is geothermal.

> *Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps for Building Heating and Cooling Electrification in the United States*[7]

The abstract:

> *This report presents the results of a study on the potential grid impacts of national-scale mass deployment of geothermal heat pumps (GHPs) coupled with weatherization in single-family homes (SFHs) from 2022 to 2050. GHPs are a technology readiness level 10, commercially available technology across the United States. This study is an impact analysis only; installed costs and available land areas for installing GHPs are not accounted for in determining their estimated deployment. The three scenarios studied were (1) continuing to operate the grid as it is today (the Base scenario), (2) a scenario to reach 95% grid emissions reductions by 2035 and 100% clean electricity by 2050 (the Grid Decarbonization scenario), and (3) a scenario in which the Grid Decarbonization scenario is expanded to include the electrification of wide portions of the economy, including building heating (the Electrification Futures Study or EFS scenario). The analysis team modeled each of these three scenarios with and without GHP deployment to a large percentage of US building floor space. In all cases, deployment of approximately 5 million GHPs per year demonstrated system cost savings on the grid, consumer fuel cost savings through eliminated fuel combustion for space heating, and CO_2 emission reductions from avoided on-site fuel combustion—and, in the case of the Base scenario, CO_2 emissions reductions from the electric power sector. GHPs have traditionally been viewed as a building energy technology. The most notable result of this study, however, is the demonstration that GHPs coupled with weatherization in SFHs are primarily a grid cost reduction tool and technology that, when deployed at a national*

[7] Online at: https://info.ornl.gov/sites/publications/Files/Pub196793.pdf

> *scale, also substantially reduces CO_2 emissions, even in the absence of any other decarbonization policy*.

Distributed generation, siting generation near load, and particularly solar, would have an impact on "need" for the project.

Renewable Energy: Distributed Generation Policies and Programs[8]

The EIS must consider the impact of siting distributed generation near Sherco, beyond the 710MW already planned for the area. For example, siting solar and storage on the proposed Microsoft data center at the Sherco site[9], and other large buildings in the area.

The EIS must consider storage as an alternative. Former FERC chair testified in Wisconsin's Cardinal-Hickory Creek of storage as a feasible alternative to transmission, and that FERC had adopted regulations to facilitation storage projects. See attached DALC-Wellinghoff Direct, pages 8-15. Given at least two transmission projects seeking to interconnect at "Big Oaks," which is adjacent to the Sherco site, that may be a way to feed storage to interconnect at Sherco.[10] See also NYISO Storage as Transmission.[11]

The EIS, when considering alternatives, must keep in mind that a combination of alternatives may well meet the need, and must not separate out each potential alternative and base feasibility on whether it meets the full claimed "need."

THE EIS MUST CAREFULLY ADDRESS THE NEED ISSUES OF SIZE, TYPE, AND TIMING

The EIS needs to take a look at the standard environmental factors and more importantly a hard look at the Certificate of Need aspects of size, type, and timing that have an environmental impact. The mere suggestion that this project should be approved is absurd. It should not be approved or constructed when we know Xcel wants this project for corporate desires, and not for any regulatory definition of need. It is not the job of ratepayers and landowners to shoulder the burden of fulfilling Xcel's corporate desires and wants.

Very truly yours,

Carol A Overland

Carol A. Overland
Attorney at Law
for NoCapX 2020

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[8] Online at: https://www.energy.gov/scep/slsc/renewable-energy-distributed-generation-policies-and-programs
[9] Online at: https://www.startribune.com/microsoft-building-data-center-in-becker-xcel-stress-on-grids/600344079/
[10] See Big Stone-Big Oaks, PUC Docket E015/CN-22-538; Northland Reliability Project, Itasca County to Benton County Dockets E015,ET2/CN-22-416 and E015,ET2/TL-22-415.
[11] Online at: https://www.nyiso.com/documents/20142/38699263/Storage%20as%20Transmission%20-%20Introduction.pdf

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January 24, 2024

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Executive Secretary via eDockets only
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RE: Comment and Exhibits
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Dear Mr. Seuffert:

As we say in transmission, "It's all connected." I'm filing these supporting documents prior to the meeting today so that I can keep them for reference on this project's road show.

Attached to this letter, please find a copy of the Commission's August 10, 2023 Order Authorizing Joint Procedures in the above-named dockets, highlighted with comments in pen. This Order has a very important fact, that 2,200 MW of generation would deliver "approximately 1,996 MW to the Sherco Substation." This presumes "approximately" 204 MW line loss, if 160 miles, 12.75%, and if 180 miles, 11.33% is lost. I'm very grateful to see that at long last the Commission is recognizing, in an Order, the inherent inefficiencies of transmission over distance.

Also attached is a Strib article of September 21, 2023, "Minnesota regulators vote to move forward the third large Xcel solar project in Becker." This article notes the Commission's prior approval of "Sherco Solar 1 and 2" of 460 MW, and the approval of "Sherco 3" solar at 250 MW. The "Sherco 3" project compensates for the line loss of the Lyon Co. to Sherco line!

Another consideration is that the 710 MW of these projects is over a third of the interconnection capacity of 1,996 MW that Xcel wants to preserve at that Sherco site. 1,996 less 710 is 1,286 MW remaining of transmission interconnection capacity for Xcel to find.

Also filed separately are selected pages of Xcel's Lyon Co. to Sherco application, with highlighted points that should be considered in analyzing this project. Most importantly is the admission of nominal increase in peak demand. The application is inconsistent in its claim, first that peak demand is expected to increase at a rate of 0.2% into the 2030s, and later in the application, that number is -0.2%. We'll need to establish which number is correct. Either way, this is a much more realistic projection than was used to justify CapX 2020, the absurd 2.49% of demand increase that at the time intervenors knew was a gross overstatement, and which obviously did not pan out.

As this docket moves forward, the Commission should also keep in mind that Xcel is selling 1,500MW of "excess capacity" on the market, energy not needed to serve its native load. This "excess capacity" should be considered in the calculation of need.

Another point to keep front and center in need consideration is the decrease in reserve margins. For decades we've been told that transmission build-out will decrease the necessary reserve margin, and that has at long last happened, or is admitted by Xcel. Typically, the MAPP, then MISO, reserve margin was set at 15%. The NERC Long-Range Transmission Reliability Assessment through the years has shown that with projected generation additions, there is far above that 15% of generation over and above area "need." The Commission should take into account the analysis of utility provided information when considering "need" for any project.

As always, the cost/benefit analysis should be carefully reviewed. In MISO cost/benefit determinations, the benefits are all to the utility/members of MISO. Similarly with this project, the benefits accrue to Xcel in preserving its "valuable transmission interconnection rights" and continued transmission service revenue, and the costs are falling to the ratepayers, to the projects lining up to interconnect, and to landowners who lose their land for easements.

There's a lot to consider when looking at "need" for this project. We know Xcel wants this project, but Xcel is hard-pressed to demonstrate need.

Very truly yours,

Carol A. Overland

Carol A. Overland
Attorney at Law

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Xcel Energy for a Certificate of Need for Two Gen-Tie Lines

ISSUE DATE: August 10, 2023

DOCKET NO. E-002/CN-22-131

ORDER AUTHORIZING JOINT PROCEEDINGS

PROCEDURAL HISTORY

On March 9, 2023, Xcel Energy (Xcel) filed a certificate of need application for two generation-tie lines in Sherburne and Lyon counties.

On May 2, 2023, the Commission accepted the application as complete and authorized use of informal proceedings for developing the record.

On May 18, 2023, Xcel filed a revised application with an updated load forecast.

By June 29, 2023, approximately 19 members of the public had filed comments on the proposed project.

On June 29, 2023, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

Xcel's proposed project includes two 345 kilovolt transmission lines (generation tie lines), and associated facilities, that are approximately 160- to 180-miles in length and would connect the Sherburne County Generation Station Substation in Becker to a new substation in Lyon County. The Project would also include an intermediate substation and a substation to store voltage support equipment.

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.

presumes 200MW losses
over 10%

160 = 12.75%
180 = 11.33%

Existing Xmsn Rights ≈ 2,000 total
Revised App. p.4

Wind & Solar - 25-40% capacity
less 10% line loss = 15-30%! Inefficient!

Delivery of "at least 1,996 MW" Revised App. p.1

By the time the Commission met to consider the matter, at least 19 members of the public had filed comments on what they anticipate will be the proposed associated transmission line route, although the Company has not yet filed a route permit application.

Under Minn. R. 7849.1900 and 7850.1600, the Commission has authority to combine the review of two applications if it is feasible, more efficient, and would further the public interest to do so.

Based on the public comments and the potential for confusion over how to participate in two separate proceedings related to the same project, the Commission finds that it would be beneficial to those interested in, and potentially affected by, the proposed project if the certificate of need and route permit applications were reviewed jointly, including by holding joint hearings and conducting joint environmental review. Separate proceedings could cause confusion over which meetings and hearings to attend and when to submit comments. Combining the review process is likely to increase the level of meaningful public participation by ensuring that interested persons know when and how to participate at each stage throughout the proceeding. In the interim, the Commission will suspend review of the certificate of need application in anticipation of the accompanying route permit application.

No party objected to this approach.

ORDER

1. The Commission hereby directs joint proceedings to be held on the certificate of need application and the forthcoming route permit application for the proposed Sherburne County to Lyon County generation-tie lines project, and suspends review of the certificate of need application until Xcel has filed a route permit application.

2. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Will Seuffert
Executive Secretary

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BUSINESS

Minnesota regulators vote to move forward the third large Xcel solar project in Becker

The Minnesota Public Utilities Commission approved the land acquisition and other details for the project.

By Mike Hughlett (https://www.startribune.com/mike-hughlett/6370445/) Star Tribune

SEPTEMBER 21, 2023 — 7:26PM

Xcel Energy plans to create one of the largest U.S. solar power complexes — an overall investment of over $1 billion — took a big step forward Thursday.

The Minnesota Public Utilities Commission (PUC) unanimously approved Xcel's acquisition of land rights for the Sherco 3, a solar plant that will complement Xcel's already permitted Sherco 1 and 2 projects in Becker.

Sherco 3, which is expected to cost $409 million, still must get a permit from the PUC.

"I think it is an important project for a lot of reasons," Commissioner Joe Sullivan said at a PUC meeting Thursday. "I applaud the company for working with the community as it retires" the Sherco coal plants.

Xcel is slated to close the three massive coal-fired power generators in Becker by 2030, with the first shutdown slated for year's end. Xcel's Sherco solar power plants will be in the Becker area.

Sherco Solar 1 and 2 — a two-phase project approved by the PUC last year — has a $690 million price tag and will be able to generate up to 460 megawatts of electricity. Sherco 3 will have the capacity to produce up to 250 megawatts of power.

460
250
710 MW

To put that in perspective, the largest solar array in Minnesota now is Xcel's 100-megawatt project in Chisago County.

The three Sherco coal generators in Becker have a total capacity of around 2,200 megawatts; the one slated to close at years' end is rated at 680 megawatts. (Coal plants, of course, can run constantly, unlike solar, though coal power is a major emitter of carbon dioxide.)

Xcel plans to complete the entire Sherco solar complex by the end of 2025.

The PUC on Thursday decided that Sherco Solar 3 is in the public interest and also approved Xcel's proposal to recover the company's costs through a renewable energy rider on customers' bills.

The PUC, in addition, decided that the Apple River solar project in Wisconsin's Polk County is in the public interest.

That 100-megawatt solar array would be developed by National Grid Renewables. It would sell electricity to Xcel under a 20-year contract. Xcel would own and build the Sherco projects. The Apple River project must still be permitted.

"The economic and societal benefits are well-articulated in the record for the Apple River [contract] as well as for the Sherco project," PUC Chair Katie Sieben said at Thursday's meeting.

The Sherco solar arrays are expected to create hundreds of union construction jobs and tens of millions of dollars in local tax revenues and payments to landowners who host solar panels.

The Sherco 3 and Apple River projects are expected to decrease customers' bills from 2025 through 2035, Xcel said in a PUC filing. However, the projects could lead to bill increases during the following ten years.

Costs for solar projects have been soaring in the past two years. Sherco 1 and 2's $690 million price tag is 20 % higher than Xcel originally expected. Federal tax credits for solar have helped blunt the cost increases.

Still, in a 2022 bid for solar proposals, Xcel found only two projects that were cost-effective for its customers, Sherco 3 and Apple River, PUC filings show. Together, those projects will have 350 megawatts of capacity, well short of the at least 900 megawatts Xcel put out to bid.

The PUC has approved price caps for all three of the Sherco solar projects.

Mike Hughlett covers energy and other topics for the Star Tribune, where he has worked since 2010. Before that he was a reporter at newspapers in Chicago, St. Paul, New Orleans and Duluth.

mike.hughlett@startribune.com 612-673-7003

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

In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota	OAH DOCKET NO. 7-2500-20283-2 PUC DOCKET NO. ET-2/TL-08-1474

AFFIDAVIT OF BRUCE McKAY, P.E.

Bruce McKay, P.E., after affirming or being duly sworn on oath, states and deposes as follows:

1. My name is Bruce McKay. I am an electrical engineer, and licensed Professional Engineer, in the state of Minnesota.

2. My experience is primarily in the areas of industrial power distribution and industrial automation and control. To date, I have 16 years experience in these areas as a licensed Master Electrician, followed by 14 years as a licensed Professional Engineer.

3. I am a landowner about 3 miles north of the proposed Le Sueur-Henderson crossing and about 7 miles south of the proposed Belle Plaine crossing and therefore am not potentially directly affected by either route proposed for the CapX2020 Brookings transmission line.

4. I have participated in Task Force meetings held in Henderson, attended one day of PUC hearings in St. Paul, and attended, including making comments and submitting statements, all but one of the Public Hearings held in the Le Sueur-Henderson area over the last couple of years.

5. The first purpose of this statement is to point out the fact that the CapX2020 Magnetic Field tables and charts that I've seen at public hearings and been able to find in CapX2020 documents all fail to address the <u>full potential Magnetic Field</u> along the transmission lines. Each table and chart that I've seen displays Magnetic Field data calculated from <u>estimated</u> Peak and <u>estimated</u> Average System Conditions (Current (Amps)) rather than from transmission line <u>design capacities</u>. An example of such a table is presented in the attached "Exhibit A - Table 3-4. Calculated Magnetic Fields - Application", which is from the CapX2020 Engineering Design, Construction and Right-of-Way Acquisition document, December 2008, pages 3-20 through 3-22.

6. The second purpose of this statement is to point out the fact that a problem with a table such as this is that it underestimates the Magnetic Field that would be created if the transmission line was utilized to its full potential capacity. The attached "Exhibit B - CALCULATED MAGNETIC FIELD TABLES" presents an example of

Magnetic Field calculations based on estimated transmission line currents as compared to Magnetic Field calculations based on future potential (design) transmission line currents. By following through STEPS 1, 2, 3, and 4 in Exhibit B, you can see that the Calculated PEAK MAGNETIC FIELDS increase by 414% and the Calculated AVERAGE MAGNETIC FIELDS increase by 540% when design capacities are used for the calculations rather than using estimated load currents. (Please Note: Exhibit B is presented as a conceptual example. Actual design capacities and associated Magnetic Field calculations would need to be and should be provided by the Applicants.)

7. The third purpose of this statement is to stress that right-of-way corridor widths along the proposed transmission line need to be based on Calculated Magnetic Fields derived from design capacities, NOT on Calculated Magnetic Fields derived from estimated transmission line currents.

8. It is my opinion that a right-of-way based on low transmission line current estimates does not sufficiently protect people living near the transmission lines from potential negative health effects resulting from the line's Magnetic Field.

9. Please feel free to contact me with any comments or questions you have.

Further your affiant sayeth naught.

Dated: October 16, 2010

Bruce McKay

Bruce McKay, PE
e-mail: bmckay.aces@gmail.com
cell: 612-386-5983

Signed and sworn to before me this
15th day of October, 2010.

Notary Public

ELIZABETH A MOEN
Notary Public
Minnesota
My Commission Expires Jan. 31, 2012

EXHIBIT A

Table 3-4. Calculated Magnetic Fields – Application

Table 3-4. Calculated Magnetic Fields (milligauss) for Proposed Single/Double/Triple Circuit Transmission Line Designs (3.28 feet above ground)

				Distance to Proposed Centerline											
Structure Type	Section	System Condition	Current (Amps)	-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
Single Pole Davit Arm 345 kV/345 kV Double Circuit with both Circuits In Service	Brookings to Lyon County	Peak	826.7	0.60	1.81	10.40	19.02	37.45	94.04	37.90	19.33	10.61	1.86	0.61
		Average	496.02	0.36	1.08	6.24	11.41	22.47	56.42	22.74	11.60	6.36	1.11	0.36
Single Pole Davit Arm 345 kV/345 kV Double Circuit with one Circuit In Service	Brookings to Lyon County.	Peak	826.7	2.23	4.65	13.88	20.14	30.96	80.21	56.92	34.74	22.25	6.16	2.70
		Average	496.02	1.34	2.79	8.33	12.09	18.58	48.13	34.15	20.85	13.35	3.69	1.62
Single Pole Davit Arm 345 kV/345 kV Double Circuit with both Circuits In Service	Lyon County to Hazel Creek	Peak	644.3	0.47	1.41	8.10	14.83	29.19	73.29	29.54	15.07	8.27	1.45	0.47
		Average	386.58	0.28	0.85	4.86	8.90	17.51	43.97	17.72	9.04	4.96	0.87	0.28
Single Pole Davit Arm 345 kV/345 kV Double Circuit with one Circuit In Service	Lyon County to Hazel Creek	Peak	644.3	1.74	3.62	10.82	15.70	24.13	62.52	44.36	27.08	17.34	4.80	2.10
		Average	386.58	1.04	2.17	6.49	9.42	14.48	37.51	26.62	16.25	10.41	2.88	1.26
Single Pole Davit Arm 345 kV/345 kV Double Circuit with both Circuits In Service	Hazel Creek to Minnesota Valley	Peak	247.4	0.18	0.54	3.11	5.69	11.21	28.14	11.34	5.79	3.17	0.56	0.18
		Average	148.44	0.11	0.32	1.87	3.42	6.72	16.88	6.81	3.47	1.90	0.33	0.11
Single Pole	Hazel	Peak	247.4	0.67	1.39	4.15	6.03	9.27	24.01	17.03	10.40	6.66	1.84	0.81

CapX2020 Delivering electricity you can rely on

Distance to Proposed Centerline														
Structure Type	**Section**	**System Condition**	**Current (Amps)**	**-300'**	**-200'**	**-100'**	**-75'**	**-50'**	**0'**	**50'**	**75'**	**100'**	**200'**	**300'**
Davit Arm 345 kV/345 kV Double Circuit with one Circuit In Service	Creek to Minnesota Valley	Average	148.44	0.40	0.83	2.49	3.62	5.56	14.40	10.22	6.24	4.00	1.11	0.48
Single Pole Davit Arm 345 kV/345 kV Double Circuit with both Circuits In Service	Helena to Lake Marion	Peak	1005.9	0.73	2.2	12.65	23.15	45.57	114.42	46.12	23.53	12.91	2.26	0.74
		Average	603.54	0.44	1.32	7.56	13.89	27.34	68.65	27.67	14.12	7.74	1.36	0.44
Single Pole Davit Arm 345 kV/345 kV Double Circuit with one Circuit In Service	Helena to Lake Marion	Peak	1005.9	2.71	5.66	16.89	24.51	37.68	97.60	69.26	42.28	27.07	7.49	3.28
		Average	603.54	1.63	3.39	10.13	14.71	22.61	58.56	41.56	25.37	16.24	4.49	1.97
Single Pole Davit Arm 345 kV/345 kV Double Circuit with both Circuits In Service	Lake Marion to Hampton	Peak	354.8	0.26	0.78	4.46	8.16	16.07	40.36	16.27	8.30	4.55	0.80	0.26
		Average	212.88	0.15	0.47	2.68	4.90	9.64	24.21	9.76	4.98	2.73	0.48	0.16
Single Pole Davit Arm 345 kV/345 kV Double Circuit with one Circuit In Service	Lake Marion to Hampton	Peak	354.8	0.96	2.00	5.96	8.65	13.29	34.43	24.43	14.91	9.55	2.64	1.16
		Average	212.88	0.57	1.20	3.57	5.19	7.97	20.66	14.66	8.95	5.73	1.59	0.69
H-Frame 345 kV/345 kV/69kV Triple Circuit	Cedar Mountain to Helena	Peak	776/776/138	0.9	2.5	13.5	24.9	48.7	68.1	14.6	6.7	3.5	0.5	0.2
		Average	466/466/83	0.5	1.5	8.1	15.0	29.2	40.9	8.8	4.0	2.1	0.3	0.1

Structure Type	Section	System Condition	Current (Amps)	Distance to Proposed Centerline										
				-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
H-Frame 345 kV/345 kV/115kV Triple Circuit	Lyon County to Cedar Mountain	Peak	841/841/ 266	1.3	3.2	15.9	28.3	52.9	67.4	15.3	8.0	4.6	1.1	0.6
		Average	505/505/ 160	0.75	2.0	9.5	17.0	31.8	40.5	9.2	4.8	2.7	0.6	0.3
Single Pole, 115 kV Single Circuit	Redwood Falls – Franklin to Cedar Mountain	Peak	266	0.3	0.6	2.3	3.9	7.7	33.9	7.4	3.8	2.3	0.6	0.3
		Average	150	0.2	0.4	1.4	2.3	4.6	20.4	4.4	2.3	1.4	0.4	0.2
Single Pole, 345 kV / 345 kV Double Circuit with one Circuit strung at 230 kV	Minnesota Valley to Hazel Creek	Peak	247	0.8	1.8	6.5	10.1	16.6	23.8	9.2	6.0	4.2	1.4	0.7
		Average	148	0.5	1.1	3.9	6.1	10.0	14.3	5.5	3.6	2.5	0.8	0.4

EXHIBIT B

Calculated Magnetic Field Tables

STEP 1

THIS TABLE CONTAINS THE COLUMN HEADINGS AND DATA FROM THE TOP ENTRY IN THE TABLE FROM EXHIBIT A1

TABLE 3-4. Calculated Magnetic Fields (milligauss) for Proposed Single/Double/Triple Circuit Transmission Line Designs (3.28 feet above ground)

STRUCTURE		SYSTEM	CURRENT	DISTANCE TO PROPOSED CENTERLINES										
TYPE	SECTION	CONDITION	(AMPS)	-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
SINGLE POLE		PEAK	826.70	0.60	1.81	10.40	19.02	37.45	94.04	37.90	19.33	10.61	1.86	0.61
DAVIT ARM	BROOKINGS	AVERAGE	496.02	0.36	1.08	6.24	11.41	22.47	56.42	22.74	11.60	6.36	1.11	0.36
345 kV / 345 kV	TO LYON													
DOUBLE CIRCUIT W/	COUNTY													
BOTH CICUITS IN														
SERVICE														

STEP 2

MVA CALCULATED FROM THE CURRENTS IN TABLE 3-4:

345.00	kV
826.70	Amps PEAK ESTIMATED
1.73	3 Phase
493.42	MVA PEAK CALCULATED
345.00	kV
496.02	Amps AVERAGE ESTIMATED
1.73	3 Phase
296.05	MVA AVERAGE CALCULATED

STEP 4

THIS TABLE CONTAINS DATA SCALED FROM THE TABLE ABOVE USING CURRENTS CALCULATED IN STEP 3

TABLE 3-4 SCALED. Calculated Magnetic Fields (milligauss) for Proposed Single/Double/Triple Circuit Transmission Line Designs (3.28 feet above ground)

STRUCTURE		SYSTEM	CURRENT	DISTANCE TO PROPOSED CENTERLINES										
TYPE	SECTION	CONDITION	(AMPS)	-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
SINGLE POLE		PEAK	3434.70	2.49	7.52	43.21	79.02	155.59	390.71	157.46	80.31	44.08	7.73	2.53
DAVIT ARM	BROOKINGS	AVERAGE	2680.74	1.95	5.84	33.72	61.67	121.44	304.92	122.90	62.69	34.37	6.00	1.95
345 kV / 345 kV	TO LYON													
DOUBLE CIRCUIT W/	COUNTY													
BOTH CICUITS IN														
SERVICE														

STEP 3

CURRENT CALCULATED FROM MVA DESIGN CAPACITY:

2050.00	*MVA PEAK DESIGN
345.00	kV
1.73	3 Phase
3434.70	Amps PEAK CALCULATED
1600.00	**MVA AVERAGE DESIGN
345.00	kV
1.73	3 Phase
2680.74	Amps AVERAGE CALCULATED

NOTES:
1. MVA = (kV * Amps * 1.73) /1000
2. Amps = (MVA * 1000) / (kV * 1.73)
3. For a given physical and electrical configuration, milligauss at one location is proportional to current (Amps) (for example, double the current and the milligauss level also doubles).
4. For a given physical and electrical configuration and constant current, the milligauss level changes as the inverse square of the distance from away from the source (for example, move 2 times as far away and the milligauss level decreases to 1/4 of what it was).

*. MVA PEAK DESIGN CAPACITY IS FROM Docket No. E002/CN-06-1115, TRANSMISSION CAPACITY

**. MVA AVERAGE DESIGN CAPACITY WAS CHOSEN TO BE ABOUT 80% OF PEAK DESIGN CAPACITY

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Xcel Energy for a Certificate of Need for Two Gen-Tie Lines

ISSUE DATE: August 10, 2023

DOCKET NO. E-002/CN-22-131

ORDER AUTHORIZING JOINT PROCEEDINGS

PROCEDURAL HISTORY

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On May 2, 2023, the Commission accepted the application as complete and authorized use of informal proceedings for developing the record.

On May 18, 2023, Xcel filed a revised application with an updated load forecast.

By June 29, 2023, approximately 19 members of the public had filed comments on the proposed project.

On June 29, 2023, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

Xcel's proposed project includes two 345 kilovolt transmission lines (generation tie lines), and associated facilities, that are approximately 160- to 180-miles in length and would connect the Sherburne County Generation Station Substation in Becker to a new substation in Lyon County. The Project would also include an intermediate substation and a substation to store voltage support equipment.

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.

By the time the Commission met to consider the matter, at least 19 members of the public had filed comments on what they anticipate will be the proposed associated transmission line route, although the Company has not yet filed a route permit application.

Under Minn. R. 7849.1900 and 7850.1600, the Commission has authority to combine the review of two applications if it is feasible, more efficient, and would further the public interest to do so.

Based on the public comments and the potential for confusion over how to participate in two separate proceedings related to the same project, the Commission finds that it would be beneficial to those interested in, and potentially affected by, the proposed project if the certificate of need and route permit applications were reviewed jointly, including by holding joint hearings and conducting joint environmental review. Separate proceedings could cause confusion over which meetings and hearings to attend and when to submit comments. Combining the review process is likely to increase the level of meaningful public participation by ensuring that interested persons know when and how to participate at each stage throughout the proceeding. In the interim, the Commission will suspend review of the certificate of need application in anticipation of the accompanying route permit application.

No party objected to this approach.

ORDER

1. The Commission hereby directs joint proceedings to be held on the certificate of need application and the forthcoming route permit application for the proposed Sherburne County to Lyon County generation-tie lines project, and suspends review of the certificate of need application until Xcel has filed a route permit application.

2. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Will Seuffert
Executive Secretary

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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct And Operate a New 345 kV Transmission Line From the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project	)	5-CE-146

DIRECT TESTIMONY OF JON WELLINGHOFF
ON BEHALF OF THE DRIFTLESS AREA LAND CONSERVANCY
AND WISCONSIN WILDLIFE FEDERATION

TESTIMONY SUMMARY

There is not sufficient evidence of record for this Commission to definitively conclude that the Cardinal-Hickory Creek (CHC) transmission line project is the highest priority energy option that is also cost effective and technically feasible as required by Wisconsin law. My conclusion is based on the Application in this proceeding, the direct testimony and exhibits submitted by the Applicants, the responses to data requests from the parties, and the testimony and exhibits submitted by witnesses for the Driftless Area Land Conservancy and Wisconsin Wildlife Federation (DALC-WWF).

In order to determine the highest priority energy option that is cost effective and technically feasible, this Commission should direct the Applicants to develop technically feasible least cost Alternative Transmission Solutions (ATS) that are properly and fully formulated and optimized. Once the ATSs are formulated, their total estimated costs should be compared to the updated total projected costs of the CHC transmission line project rather than simply the allocated Wisconsin share in order to achieve a true apples-to-apples comparison of cost effectiveness of alternative project options. Upon completing this analysis, Applicants should submit the analysis to the Commission for a determination of which alternative is the highest priority energy option to be selected for Wisconsin, and other parties should be allowed a full and fair opportunity to respond.

The Commission is likely to find that a properly analyzed ATS is the most cost effective alternative for the Cardinal-Hickory Creek project because: there are a number of significant high priority energy options that could be included in that analysis that Applicants have failed to consider, the price of solar energy generation is rapidly declining as solar panels become more efficient, energy storage costs are rapidly declining, and there are many untapped low cost energy efficiency and demand response opportunities that can be realized. Solar energy is an especially valuable peak resource as the Commission recently recognized in approving 500 megawatts of new solar projects in Wisconsin. ATS involving robust combinations of these resources are more flexible, more in-state, more available at peak when most needed and can be more cost effective compared to approving a Certificate of Public Convenience and Necessity (CPCN) which locks in for 40 years a potentially less flexible high voltage transmission line alternative carrying an unspecified mix of out of state electricity generation to Wisconsin and potentially displacing development of more renewable energy resource projects in Wisconsin.

The Commission should adopt this "no regrets" approach. Approving this Application now without having a proper comparable analysis of the alternatives would potentially result in adopting a suboptimal alternative. Such action by this Commission may fail to deliver the benefits that an optimal portfolio of cost effective high priority resources could deliver to the state. Furthermore, there is no near term reliability need that would require proceeding with the proposed CHC transmission line project now without conducting the full and fair ATS analysis that I have explained in my testimony.

Moreover, based on my experience as Chair of the Federal Energy Regulatory Commission (FERC) and my overall utility regulatory and market experience, the costs of Alternative Transmission Solutions, including ones that incorporate high priority energy options as I discuss below, should be eligible for regional cost-sharing by the Midcontinent Independent

System Operator (MISO). This is certainly true if the ATS provides comparable services and is more cost effective than the proposed Cardinal-Hickory Creek transmission line.

Q: Please state your name, employer, title, and business address.

A: My name is Jon Wellinghoff. I am Chief Executive Officer for GridPolicy, Inc. My business address is 2120 University Ave, Berkeley, CA 94704.

Q: Please describe your current position and provide your education and professional experience as it relates to this direct testimony.

A: I have been an energy regulatory attorney and consultant for the past forty-three (43) years holding various positions at the local, state and federal government level as well as industry. I have served as the Chair and as a Commissioner of the Federal Energy Regulatory Commission (FERC), in senior-level federal and state utility and energy regulatory positions, and in senior-level private sector business positions as more fully explained below.

I have testified in a number of proceedings including before the regulatory commissions of Nevada, Texas, Washington and the District of Columbia, the U.S. Congress and the Federal Trade Commission (FTC). I have been offered to testify as an expert on Integrated Resource Planning (Nevada), energy efficient lighting systems (Texas and D.C.), solar energy industry (FTC), transmission planning procedures and policies (U.S. Congress, House of Representatives) and demand response (private lawsuit).

I am currently the CEO of GridPolicy, Inc., an international consulting firm. We provide energy policy and strategic consulting services to our client base on a range of topics including wholesale and retail electric energy services and markets, transmission and distribution grid issues, distributed energy resources (DER), renewable energy, storage and other issues related to electric energy systems and markets.

Previously, I was the Chief Policy Officer for SolarCity/Tesla, which, at that time, was the largest developer of both residential and commercial solar systems in the U.S. While I worked at SolarCity, we were responsible for the development and installation of over one gigawatt of rooftop, community and large scale solar, and solar plus storage systems.

I served as a Commissioner at the Federal Energy Regulatory Commission (FERC) from 2006 through 2013, and was designated Chairman by the President for the last five of those years. At FERC, I initiated and/or assisted in the development of rulemaking proceedings on demand response (Order 755, Order 745 and Order 719), transmission planning (Order 890 and Order 1000), renewable system integration into the transmission grid (Order 764) and accounting for new electric storage systems (Order 784) among other issues and Orders. While serving as Chair of FERC, I also initiated a reporting system for demand response that provides data on the historical installed capacity of and future potential for demand response within the transmission grid.

I also served as a regulatory attorney at the Federal Trade Commission in the Bureau of Consumer Protection, Division of Energy Product Information. I was responsible for oversight of the solar industry from the perspective of industry product information being provided to consumers.

I served as Nevada's first Advocate for Consumers of Public Utilities, heading a division of the Nevada Attorney General's Office working to protect the interests of utility ratepayers. While serving in that position, I participated in numerous certificate proceedings for transmission lines as well as Integrated Resource Planning (IRP) proceedings analyzing alternatives to transmission projects. In 1983, I wrote the IRP statute for Nevada, which was later adopted in whole or in part by seventeen (17) other state jurisdictions.

I served as General Counsel to the Nevada Public Utilities Commission. Again, in that position, I participated in transmission certificate proceedings and in IRP proceedings analyzing transmission and transmission alternatives.

I was the regional director of NORESCO, one of the nation's largest energy service companies, providing comprehensive energy efficiency, demand response and renewable energy project development services to commercial and industrial customers in the Southwestern U.S.

I was also one of two principals in the energy efficiency-consulting firm, Efficiency Energy Systems, Inc. (EEIS). As an EESI principal, I oversaw the specification and installation of over ten megawatts of energy efficient lighting upgrades in the facilities of multiple clients such as Nellis Air Force Base, Southern California Edison, Pasadena City College, Hawaiian Electric, Orange County School District and others. Also, as an EESI principal, I designed the curriculum and taught energy efficient lighting system technology and auditing to over 300 of Southern California Edison's Energy Service Representatives.

I received a BS in mathematics from the University of Nevada, Reno, a MAT in mathematics from Howard University, and a JD from Antioch School of Law. Although my BS is in mathematics, I started my academic career as physics major. Thus, before changing my major I took all the physics courses required of an engineering major.

I have been a member of the Nevada State Bar since 1975. My complete résumé is attached as Ex.-DALC-WWF-Wellinghoff-1**.**

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of the Driftless Area Land Conservancy and the Wisconsin Wildlife Federation (DALC-WWF), which are intervenor parties in this proceeding.

Q: What is the purpose of your direct testimony?

A: The purpose of my testimony is to review the Application in this proceeding for the proposed Cardinal-Hickory Creek (CHC) transmission line and specifically the "Non Transmission Alternative" (NTA) analysis conducted by the Applicants. I will relate that NTA analysis to both Wisconsin statutory requirements and the requirements for transmission planning under applicable FERC standards.

Q: Do you have any exhibits to offer in support of your direct testimony?

A: Yes.

- Ex.-DALC-WWF-Wellinghoff-1
- Ex.-DALC-WWF-Wellinghoff-2
- Ex.-DALC-WWF-Wellinghoff-3
- Ex.-DALC-WWF-Wellinghoff-4
- Ex.-DALC-WWF-Wellinghoff-5

Q: What are the Wisconsin requirements regarding evaluation of alternatives to transmission projects in a proceeding such as this one?

A: The Public Service Commission of Wisconsin (PSCW or Commission) stated in its Final Decision in the Badger Coulee transmission line case: "The Commission has the responsibility to ensure that Wisconsin receives adequate, reliable, and economical electric service now and in the future."[1]

In that context, the Commission is required by statute, to the extent cost effective and technically feasible, to consider options to meet energy demands by prioritizing energy conservation and efficiency and noncombustible renewable energy resources before other energy resources.[2] Regarding those priorities, the Wisconsin Supreme Court stated that in a case such as this one for a Certificate of Public Convenience and Necessity (CPCN):

> *The EPL itself states that the priorities are to be applied '[i]n meeting energy demands." Wis. Stat. § 1.12. Wisconsin Stat. § 196.025(1) states the priorities of § 1.12(4) are to be applied "in making all energy-related decisions and orders.' When the PSC makes a determination on a CPCN under the Plant Siting Law, it applies the EPL in the context of determining whether to approve the requested plant siting.* ***The question the PSC should ask is thus: Given the requirements of the Plant Siting Law, what is the***

[1] PSCW Docket No. 5-CE-142, *Final Decision* (April 23, 2015) (PSC REF#: 236151).

[2] **Wis. Stat. § 1.12(4)**

highest priority energy option that is also cost effective and technically feasible? [3]

With that framing by the Wisconsin Supreme Court, the PSCW should then ask: "Is the Cardinal Hickory Creek transmission line project the highest priority energy option that is also cost effective and technically feasible?"

Q: Did Applicants provide sufficient evidence for the Commission to answer this question?

A: No, they did not.

Q: Please explain why.

A: As I explain more fully below, and as explained in more detail in the testimony of DALC-WWF witness Kerinia Cusick, the Applicants failed to conduct a legally sufficient project options analysis that would allow a comparison of the CHC Project to Alternative Transmission Solutions (ATS) composed of feasible high priority energy resources that are optimized for cost effectiveness as required by Wisconsin law and FERC regulations.

Q: Why are you using the terminology Alternative Transmission Solutions or ATS instead of the terminology used by Applicants of Non Transmission Alternatives or NTA?

A: Although some use ATS and NTA as equivalent terms, they actually have distinct and significant legal meanings. An Alternative Transmission Solution or ATS is a term used by FERC in its Order 890 on transmission planning to designate potential alternative solutions to transmission problems that have been identified by a utility transmission provider, a third party project developer or a planning authority. Those solutions could encompass traditional transmission infrastructure such as wires and towers and substations. The FERC made clear in Order 890,

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[3] Clean Wisconsin, Inc. v. Public Service Commission of Wisconsin, 282 Wis.2d 250 (2005) at ¶ 122. Emphasis added.

however, that Alternative Transmission Solutions also encompass another category of transmission assets, Advanced Transmission Technologies (ATT). Specifically, Order 890 states:

> *436…the Commission concludes that it is necessary to amend the existing pro forma OATT to require coordinated, open, and transparent transmission planning on both a local and regional level…* ***Through EPAct 2005 sec. 1223, Congress also directed the Commission to encourage the deployment of advanced transmission technologies in infrastructure improvements****, including among others optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells, and microturbines), and enhanced power device monitoring.*
> *437. Accordingly,* ***each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule.***[4]

Q: What are Advanced Transmission Technologies?

A: The term Advanced Transmission Technologies (ATT) identifies a distinct class of potentially FERC jurisdictional transmission assets defined by Congress in the Energy Policy Act of 2005. They are broadly defined as:

> …the term 'advanced transmission technology' means a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility,…[5]

The statute then provides a list of 18 examples of ATTs that include battery storage, solar photovoltaic systems, load control and numerous other technologies.

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, p. 436-437 (2007). Emphasis added.

[5] Pub. L. 109–58, title XII, § 1223, Aug. 8, 2005, 119 Stat. 953.

Q: How are battery storage and solar PV systems considered as potential Alternative Transmission Solutions under the FERC Order 890 and Order 1000 transmission planning process?

A: For such resources to be considered as an Alternative Transmission Solution by FERC, two criteria must be met. First, they must fit within the Congressionally determined categories of an Advance Transmission Technology. Second, they must be assessed in the transmission planning process to provide transmission services for the transmission problem identified. FERC indicated a requirement for comparable treatment in the planning process for Advanced Transmission Technologies if they are found to provide transmission services in Order 890:

> *We therefore find that, where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be permitted to participate in that process on a comparable basis. This is consistent with EPAct 2005 section 1223.*[6]

Q: What does "comparable basis" and treatment mean in this context?

A: To consider Alternative Transmission Solutions comparably, each separate proposed solution should be formulated independently to provide the transmission services required to solve the transmission planning problem at issue. That formulation should be structured to use the most cost effective assets possible. Once a set of Alternative Transmission Solutions have been formulated and tested for both feasibility of resolving the planning problem and cost effectiveness they should be compared to each other to determine the most cost effective among the alternatives.

Q: What is the significance of an ATT being designated as a potential FERC jurisdictional Alternative Transmission Solution?

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[6] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, p. 479 (2007). Note the reference to EPAct 2005 section 1223 refers to Advanced Transmission Technologies.

A: Designating an Alternative Transmission Solution as an aggregation of Advanced Transmission Technologies capable of providing a transmission services solution means that the solution, as an ATS, is eligible for regional cost recovery under FERC transmission planning Orders 890 and 1000. That is a significant benefit. FERC specifically stated in Order 890:

> *Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. …* ***When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed*** *…* ***alternatives on a comparable basis****. If the public utility transmission providers in the transmission planning region, in consultation with stakeholders, determine that an alternative transmission solution is more efficient or cost-effective than transmission facilities in one or more local transmission plans, then* ***the transmission facilities associated with that more efficient or cost-effective transmission solution can be selected in the regional transmission plan for purposes of cost allocation.***[7]

Q: Did FERC also use the term "Non-Transmission Alternative" (NTA) in its transmission planning orders, and what is your understanding of the meaning and use of that term?

A: Yes, FERC referenced the term "Non-Transmission Alternative" in both Orders 890 and Order 1000. In the Introduction to Order 890, the FERC stated:

> *Transmission planning is a critical function under the pro forma OATT because it is* ***the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives****. Despite this, the existing pro forma OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans*

[7] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, P 148 (2007). Emphasis added.

> *are developed.* ***These deficiencies are serious, given the substantial need for new infrastructure in this Nation.***[8]

Q: Did FERC link the term Advanced Transmission Technology with how a Non-Transmission Alternative becomes a transmission asset as an Alternative Transmission Solution and thus eligible for cost recovery?

A: Yes. In referring to the ***"…need for new infrastructure…"*** in the above Introduction, FERC then sites the Advanced Transmission Technologies text in a section of the 2005 Energy Policy Act. This section taken together with paragraphs 436 and 437 of FERC Order 890, quoted above, makes it clear that a Non-Transmission Alternative does not become a FERC jurisdictional Alternative Transmission Solution until it meets the two criteria stated above: (1) It is classified as an Advanced Transmission Technology, and (2) It has been assessed in the planning process to be capable of providing transmission services. Then, it can be considered for regional rate base cost recovery.[9]

FERC brought home this point in Order 1000 in discussing Non-Transmission Alternatives and the mechanism for cost recovery for such alternatives in the Order, stating:

> *As we make clear above in the section on Regional Transmission Planning, we are maintaining the approach taken in Order No. 890 and will require that generation, demand resources, and transmission be treated comparably in the regional transmission planning process. However,* ***while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, we conclude that the issue of cost recovery for non- transmission alternatives is beyond the scope of the transmission cost allocation reforms we are adopting here, which are limited to allocating the costs of new transmission facilities****.*[10]

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[8] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Order 890, P 3 (2007). Emphasis added.

[9] There may be other non-discriminatory criteria established by the regional planning authority and approved by FERC to qualify for regional cost recovery.

[10] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 779 (2011). Emphasis added.

Q: Did FERC then specify under what circumstances a Non-Transmission Alternative that meets the criteria of an Alternative Transmission Solution will be eligible for cost recovery?

A: Yes. FERC indicated in a footnote to the above-quoted paragraph how Non-Transmission Alternatives could become eligible for rate base cost recovery as a transmission asset:

> *As we stated in the Proposed Rule,* ***the Commission has recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes****. See Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.58 (citing Western Grid Development, LLC, 130 FERC ¶ 61,056 (2010)).*[11]

The "appropriate circumstances" cited by the FERC are those explained above. The ATS must be an ATT (as in the case of *Western Grid Development*- battery storage) and be found by the regional planning authority (CAISO in *Western Grid's* case) to be capable of providing the transmission services needed to meet the identified regional transmission problem. FERC stated in *Western Grid* that for the ATT asset to be considered transmission infrastructure for the purposes of rate base FERC jurisdictional cost recovery, the ATT asset should "mimic" the transmission services necessary to solve the transmission need posed.[12]

Q: What are the implications of these FERC determinations regarding ATS and NTA for this case?

A: The most significant is that Applicants approached their analysis of their constricted NTA option in a manner that will potentially deny and deprive Wisconsin ratepayers of the opportunities for regional cost recovery through rate base treatment of that option at the FERC jurisdictional level.

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[11] Ibid, Fn 563. Emphasis added.

[12] *Western Grid Development, LLC*, 130 F.E.R.C. ¶ 61,056 at P 43 (2010.)

Q: Overall, how did Applicants conduct their NTA analysis?

A: In his deposition, excerpts included in Ex.-DALC-WWF-Wellinghoff-5, Applicant witness Thomas Dagenais describes the general process that he and his colleague, Erik Winsand, used to develop the NTA portfolio for this case:

> *For the non-transmission alternative we looked at the cost of the proposed project to Wisconsin rate payers, and we assumed that that same amount of dollars would be spent on non-transmission alternative developments.*
>
> *So as I discussed earlier, we had approximately $90 million in 2023 dollars to spend, and we attempted to maximize the benefits of the non-transmission alternative while hitting the four different types of non-transmission components that we included.*[13]

Q: Is this approach legally defensible under the requirements of FERC Orders 890 and 1000?

A: No. FERC requires comparability when analyzing separate transmission options. The requirement is stated repeatedly in FERC Orders 890 and 1000.

Q: How and why was the Applicants' approach not consistent with comparability?

A: Applicants started with a $90 million limit and worked from there. The Cardinal-Hickory Creek transmission line was not planned that way, so neither should comparable options such as the NTA option. Instead, the PSCW should require the Applicants to consider the NTA option on a comparable basis to other options including the CHC transmission line project as required by FERC Orders 890 and 1000.

Q: What does this mean as to how NTA options should be approached?

A: That means that NTA options should first be designed to meet the transmission needs identified in the planning process in the most cost effective manner possible and then their total costs and capabilities should

[13] Ex.-DALC-ATC-Wellinghoff-5, page 3 of 4.

be compared to all other options. There should not be such an upfront cost limit placed on the NTA options design. ATT resources should instead be cost effectively chosen and aggregated as necessary in order to best mimic the transmission services required to meet the desired transmission solution. In order to comply with Wisconsin law, Applicants should select ATT resources that optimize the portfolio for the most cost effective high priority energy resources available. Applicants clearly did not do that. They started with a basket of suboptimal resources, they also started with a cost limiting resource assumption that they should not have used.

Q: So does Applicant's analysis of its NTA option fail to meet FERC's criteria for cost recovery?

A: Yes. Applicants fail to meet the FERC criteria. First, they failed to test each of their NTA technologies against the criteria for ATT in the 2005 EPAct. They did not determine if the resource set that they chose would "…increase the capacity, efficiency, or reliability of an existing or new transmission facility…". Second, they entirely failed to design their NTA solution in a manner that would "mimic" the transmission services of the Cardinal-Hickory Creek line as required by the *Western Grid* order cited by FERC.[14] In performing their analysis in a less than rigorous and proper manner by ignoring these two critical requirements, the Applicants' NTA solution cannot be considered an ATS by FERC. Therefore, this constricted approach by the Applicants limits consideration for regional cost recovery.

Q: If a properly conducted NTA analysis had determined that the components of the NTA were ATTs and those technologies provided transmission services making the NTA an ATS, could the full cost of the ATS then be considered by FERC for rate base cost recovery?

[14] *Western Grid Development, LLC*, 130 F.E.R.C. ¶ 61,056 at P 43 (2010.)

A: Yes. The *Western Grid* case makes that clear, and FERC reiterated that point in Order 1000 as set forth above.

Q: Did MISO evaluate an NTA option as an ATS for the proposed Cardinal-Hickory Creek transmission line as part of the MVP portfolio analysis?

A: No. A review of MTEP 2011 indicates that MISO apparently did not consider an NTA as an ATS in the MVP planning process.[15]

Q: If MISO did not fully and comparably evaluate an NTA option against the CHC line as an ATS for this MVP Project, why should Applicants be required now to do so in this proceeding?

A: Because they are required to do so by Wisconsin law. As stated above, Applicants must provide sufficient evidence of record for this Commission to conclude that the proposed CHC transmission line is the highest priority energy option that is cost effective and technically feasible.

Q: Did the Applicants do that?

A: No, they did not. Instead of solving for the transmission problems and needs by optimizing a set of high priority technologies, which could comply with both Wisconsin and federal transmission planning law and regulations, they chose a seemingly random set of technologies and applied a constricted dollar cap to the total package to comprise their limited NTA. Ex.-DALC-WWF-Wellinghoff-2 sets out the technology categories, the proposed investment in 2018 and 2023 dollars, and the maximum peak megawatts saved for the Applicants' NTA technologies. These numbers are taken directly from the Applicants' work papers. From these numbers I calculated the dollars per kilowatt (kW) for each kilowatt

[15] This seems to be further confirmed from a review of the Direct Filed Testimony of MISO Witness Rauch in PSCW Docket 5-CE-142 in the Badger-Coulee proceeding where she indicated for that project that MISO only considered traditional transmission alternatives. Direct-MISO-Rauch-1, PSCW Docket 5-CE-142, September 15, 2014, p. 29, l. 3-11, DALC-ATC-00002492.

of maximum peak saved from the 2023 dollars invested (column 3/column 4/1000).

Q: What observations do you have from the numbers that you calculated?

A: It appears that Applicants propose to spend an average of $1,400/kW for each kW of maximum peak load saved in 2023 dollars. Ex.-DALC-WWF-Wellinghoff-2. This ranges from a high of $3,265/kW for the proposed residential solar component of the NTA package to $645/kW for the demand response component. From my knowledge, experience and understanding of potential NTA technologies that could be classified as Advanced Transmission Technologies and thus qualify for FERC rate recovery, the costs of the Applicants' NTA energy options are 4 to 10 times higher than would be expected if one selected an optimized bundle of Advanced Transmission Technologies to provide a comprehensive transmission services solution for Southwestern Wisconsin. Applicants appear to have chosen NTA energy options that are clearly not the most cost effective available as required by statute.

Q: Did the Applicants optimize the NTA technology bundle?

A: No, the Applicants did not. First, they improperly capped the total expenditures for the NTA bundle at $92.5 million and should have considered the full cost of the CHC transmission line project as an upper boundary.

Moreover, the PSCW Staff now states in the Draft Environmental Impact Statement:

> After considering all of the costs (including the capital cost, project financing, and operation and maintenance) that would be associated with the proposed project, the projected MVP allocated present value (discounted to year 2018) cost to the MISO footprint of the proposed Cardinal-Hickory Creek project is $629.2 million. By contrast, the "Applicants' estimate that the capital cost of the

> proposed Cardinal-Hickory Creek project would be between $492 million and $543 million in year-of-occurrence dollars."[16]

Second, the Applicants also made numerous errors and improper assumptions in technology choices and the costs of technologies. Those errors resulted in the Applicants producing a suboptimum bundle of technologies.

Q: Please explain those errors?

A: The Applicants first error is that they did not review or consider some of the most cost effective transmission specific technology available. There currently exist commercially proven, technically feasible and cost effective power line technologies that the Applicants appear to have completely ignored.

Q: What are some of these technologies and how do they fit into the FERC/Congressional definitions of ATT?

A: They are all included in the EPAct 2005, Section 1223 definitions of Advanced Transmission Technology. They all increase the capacity and/or efficiency of existing transmission facilities and improve system reliability, and they are specifically called out in Section 1223. They include: "…(14) enhanced power device monitoring…" and "…(17) power electronics and related software…".[17]

Q: What can these technologies do, and how do they work?

A: There are two types of technologies that are currently in use which meet the above ATT definitions. Both of these technologies are used in conjunction with existing transmission lines such as the 161 kV lines found in Southwest Wisconsin. When used with those lines, these technologies can improve reliability, reduce congestion and increase flows at peak periods. These are all transmission services of the type that the CHC transmission line is intended to provide. For example, one technology is an enhanced power line monitoring device that places sensors

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[16] Staff Draft Environmental Impact Statement, p.77. PSC REF#: 360500
[17] Pub. L. 109–58, title XII, § 1223, Aug. 8, 2005, 119 Stat. 953.

adjacent to the line taking measurements of line flow, ambient temperature and wind speeds. From these readings the grid operator can determine the appropriate line rating in real-time and potentially increase flows as appropriate. Using machine learning algorithms, the technology can then reliably increase the capacity on congested lines with forecasted line ratings and real-time dynamic line ratings (DLR).

The second technology is a power electronics package that can provide in essence an intelligent "valve" for transmission lines by dynamically increasing or decreasing line reactance.[18] By increasing or decreasing flows on the transmission line in real time in the flow gate, the grid operator can direct flows as needs, improving reliability and increasing throughput of the system. Minnesota is now successfully using this technology in its transmission system to improve system efficiency.[19]

Q: How cost effective are these technologies?

A: In general, they are certainly less expensive than the least expensive technology that Applicants examined, demand response at $645/kW. In certain use cases, these technologies could be as inexpensive as $100/kW.

Q: Should the Applicant have reviewed more use cases for the CHC transmission line with such technologies?

A: Yes. Ignoring these clearly cost effective and technically feasible technologies is, in part, evidence that Applicants failed to attempt to optimize an NTA solution and thus failed to meet their burden in this case.

[18] Reactance is the non-resistive component of impedance in an AC circuit. It can also be thought of as the opposition of a circuit element to a change in current or voltage due to that element's inductance or capacitance.

[19] Available at: https://www.duluthnewstribune.com/business/4124502-minnesota-power-partners-smart-wires

Q: What other concerns do you have with the Applicants' analysis of the NTA option?

A: A second error is apparent from reviewing their estimates for both utility scale solar and residential solar technologies. As shown in Ex.-DALC-WWF-Wellinghoff-4, readily available public source data demonstrates that their cost estimates for both of these technologies are much higher than is reasonable. Moreover, they apparently failed to consider in their NTA analysis over 300 MW of utility scale solar that is approved to be built in Montfort, Wisconsin close to the proposed CHC transmission line location, as well as an additional 50 MW of utility scale solar that is approved to be built in neighboring Richland County, Wisconsin. DALC-WWF witness Kerinia Cusick discusses in more detail the Applicants' failures in the area of solar technology.

Q: Do you have comments on other components of Applicants' NTA option package?

A: Yes, let me turn to a third set of errors. I have comments on both the demand response program and the energy efficiency program. First, with respect to demand response, it appears from the deposition of Applicant witness Dagenais that neither he nor his colleague, Mr. Winsand, fully considered the multiple types of demand response potentially available to provide transmission services. I conclude this from the explanation that Mr. Dagenais gave in his deposition on how he approached the NTA demand response component. He stated in his deposition at pages 47 and 48:

> *The most effective summer peak reducer is demand response where you're simple[y] having large industrial loads shut down during high usage times and they're compensated through that – to do that through more favorable rates.*
> *Looking at the load projections for the study area and evaluating where we knew industrial loads were located, we came up with – I did jot down some notes if I can refer to them. 31.5 megawatts of demand response, which we thought was a reasonable amount to*

> *assume based on the loads in the area, and then based on MISO's MTEP 18 futures workshop…they had published a dollar per kilowatt cost of the initial implementation of demand response. And we put $20 million on the $90 million towards demand response to get us the 31.5 megawatt peak savings, which is the most bang for our buck, but we didn't feel it was appropriate to go larger than that because we didn't feel based on other studies we have reviewed that it was feasible to ask industrial customers to have a larger share of demand response than that.*[20]

Q: What did Applicants overlook in this approach?

A: They appear to have focused entirely on demand response resources from industrial customers. Applicants seem to have entirely ignored the commercial and residential customer class as sources of achieving demand response.

Q: Is it technically feasible and cost effective to derive demand response resources from the commercial and residential customer classes?

A: Yes, it is technically feasible and cost effective to derive demand response resources from residential and commercial customer classes. The most recent FERC staff report on demand response indicates that in 2016, nationwide, there is a potential for over 10,000 MW of residential demand response, and over 11,000 MW of commercial sector demand response.[21] By overlooking these two large sectors, the Applicants excluded a significant transmission services resource in this case.

Q: Do you also have concerns regarding the price that Applicants used for demand response?

A: Yes, and that is a fourth error. The aggregation of demand response resources can be done by third-party aggregators or by load-serving entities. As such, the provision of demand response services can be very competitive. Certain resource assets like residential controllable thermostats may already be in place and paid

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[20] Ex.-DALC-WWF-Wellinghoff-5, p. 1-2 of 4.
[21] Available at: https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf

for by the customer. The cost to activate those resources and provide a demand response resource to reduce transmission congestion or assure reliability at peak times can be extremely low depending on the customers' perceived cost to participate. For example, Portland General is offering residential customer $1/kWh for peak demand reductions.[22] This is considerably less than the Applicants proposed cost of $645/kW.

Q: What concerns do you have regarding the Applicants energy efficiency NTA option?

A: It appears that Applicants spent their entire energy efficiency budget on LED light bulbs. That is a fifth error. Mr. Dagenais states in his deposition:

> *Q: So in your cost analysis, is it true that you assumed the entire cost of the EE measures would be charged against the NTA budget? I can rephrase that if it would be helpful.*
> *A: Yes, please.*
> *Q: How much did you assume your energy efficiency measures would cost?*
> *A: $2.4million in 2023 dollars.*
> *Q: And did you assume those costs reflected the entire cost of the energy efficiency measure or only part of the cost of that measure?*
> *A: The $2.4 million in 2023 dollars was implemented to achieve 2.6 megawatts of max peak savings in terms of energy efficiency, so, yes, the entire cost of the 2.6 megawatt max peak savings came from the pool of dollars available to the NTA.*
> *Q: And you used—you modeled those measures as LED light bulbs?*
> *A: Correct.*[23]

Q: Why is that a concern?

A: There are several significant problems with this approach. First, for LED light bulbs to be cost effective energy efficiency measures, they need to replace higher wattage incandescent and halogen bulbs. Under current United States Department of Energy regulations, however, most of the higher wattage incandescent and

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[22] Available at: https://www.utilitydive.com/news/portland-general-pilot-proposes-reward-to-customers-for-reducing-energy-use/546095/
[23] Ex.-DALC-WWF-Wellinghoff-5, p. 4 of 4.

halogen bulbs that Applicants' LED bulbs are intended to replace will no longer be manufactured or available to consumers after 2020.[24] Second, LED lighting is not the most cost effective measure that Applicants could have selected for providing maximum peak savings.

Q: Why do you believe that LED bulbs are not the most cost effective high priority energy resource that Applicants could have selected for the energy efficiency portion of their NTA option?

A: On Ex.-DALC-WWF-Wellinghoff-3, I have reproduced pages from the Wisconsin Focus on Energy Evaluation Report, Volume I, for calendar year 2016. That report sets forth data for the incentive dollars spent for all Wisconsin energy efficiency programs and the verified kilowatts saved for each program. This data indicates the residential LED program spent approximately $8.3 million and achieved kW savings of 15,639 kW for a cost of $533/kW.[25] However, the residential HVAC controls program spent $508,726 and achieved kW savings of 3,642 kW for a cost of $140/kW. Further, in the commercial sector, the commercial rooftop unit/split system AC program spent $420,400 and achieved kW savings of 1,095 kW for a cost of $384/kW. And the commercial variable speed drive program spent $1.3 million and achieved kW savings of 5,771 kW for a cost of $234/kW. Apparently Applicants failed to select the most cost effective high priority energy efficiency resources for their limited NTA option analysis.

Q: What conclusions do you reach from your analysis of the demand response and energy efficiency programs that the Applicants included in their NTA option analysis?

[24] Available at: https://www.epa.gov/cfl/how-energy-independence-and-security-act-2007-affects-light-bulbs

[25] It is interesting to note that even this figure is considerably lower than the $800/kW number of Applicants for energy efficiency programs shown on Ex.-DALC-WWF-Wellinghoff-2.

A: I conclude that Applicants failed to consider and incorporate into that analysis demand response and/or energy efficiency resources that were very cost effective and available. The Applicants' failure to do so is a critical flaw in their NTA option analysis.

Q: Please summarize your review of the Applicants' NTA option?

A: From my review, I have concluded that the NTA option presented by Applicants in this proceeding does not optimize an aggregation of the highest priority energy resources to meet the transmission service needs. By failing to do so, Applicants have not set forth a comparable Alternative Transmission Solution composed of Advanced Transmission Technologies as defined by FERC, which could then be reviewed against the CHC transmission line project and considered for cost recovery.

Q: Based on your review, what do you recommend that the Public Service Commission of Wisconsin do in this proceeding?

A: There is not sufficient evidence of record for this Commission to definitively conclude that the Cardinal-Hickory Creek transmission line project is the highest priority energy option that is also cost effective and technically feasible as required by Wisconsin law. In order to determine the highest priority energy option that is cost effective and technically feasible, this Commission should direct the Applicants to develop technically feasible least cost Alternative Transmission Solutions that are properly and fully formulated and optimized. Once the Alternative Transmission Solutions are formulated, their total estimated costs should be compared to the updated total projected costs of the CHC transmission line project rather than simply the allocated Wisconsin share in order to achieve a true apples-to-apples comparison of cost effectiveness of alternative project options.

Upon completing this analysis, Applicants should submit the analysis to the Commission for a determination of which alternative is the highest priority energy option to be selected for Wisconsin, and other parties should be allowed a full and fair opportunity to respond.

Q: Do you believe that the Commission should adopt this "no regrets" approach?

A: Yes, I do. The Commission should adopt this "no regrets" approach. Approving this Application now without having a proper comparable analysis of the alternatives would potentially result in adopting a suboptimal alternative. Such action by this Commission may fail to deliver for Wisconsin the benefits that an optimal portfolio of cost effective high priority resources could deliver to the state. Furthermore, as I understand from the testimony of DALC-WWF witness Rao Konidena, there is no near term reliability need that would require proceeding with the proposed CHC transmission line project now without conducting the full and fair ATS analysis that I have explained in my testimony.

Q: Does this conclude your testimony?

A: Yes, it does.