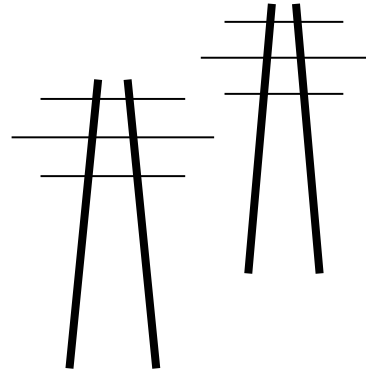


# Legalelectric, Inc.

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July 13, 2026

Sarah Bergman  
Executive Secretary  
Public Utilities Commission  
121 – 7<sup>th</sup> Place East, Suite 350  
St. Paul, MN 55101

RE: **Initial Need Comment** - World Organization of Landowner Freedom  
Iron Range – St. Louis County – Arrowhead Transmission Line  
PUC Docket E015/CN-25-111 and E015/TL-25-112  
CAH 5-2500-41817

Dear Ms. Bergman:

On behalf of World Organization of Landowner Freedom (W.O.L.F.), I submit this Initial Need Comment in the above-entitled dockets.

Need is a contested issue in this docket – in its Application, there are many claims that must be proven up under our Certificate of Need statute. Minn. Stat. §216B.243. There are also reasonable and prudent system alternatives to be addressed. A Contested Case is necessary.

The motivation for W.O.L.F.'s intervention in this docket is its interest in the preservation of the 800 MVA limitation at the Arrowhead substation. W.O.L.F. asks that the Commission leave it as it is – that there is no reasonable basis to remove it demonstrated by the Applicants.

## **I. History of Arrowhead substation and the 800 MVA limitation of bulk power transfer**

Decades ago, beginning in 1999, World Organization for Landowner Freedom (W.O.L.F.) intervened in the Arrowhead-Weston transmission dockets in both Minnesota<sup>1</sup> and Wisconsin<sup>2</sup>. This was a years' long foray. Beyond the pre-hearing activities, the Minnesota hearing lasted two weeks, and the initial Wisconsin hearing<sup>3</sup> was two months long, followed by two cost focused hearings years later – an intensive undertaking by any measure.

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<sup>1</sup> EQB Exemption docket MP-HVTL-EA-1-99. See Order, ISA Application.

<sup>2</sup> WI PSC Docket 05-CE-113.

<sup>3</sup> Attachment A, W.O.L.F. Initial Brief, WI's 05-CE-113. Not much has changed over the last 20 years

In the Minnesota EQB's Exemption proceeding, an 800 MVA limit was ordered as a means of limiting bulk power transfer of coal generated electricity from the Dakotas<sup>4</sup>.

10. Minnesota Power shall apply to the Minnesota Environmental Quality Board under section 116C.57 for authorization to make any changes in the Arrowhead substation that would allow Minnesota Power to increase the capability of the substation to transmit power over the transmission line beyond 800 MVA.

History matters. W.O.L.F. is the only intervening party in this docket with the institutional and literal memory of the evolution of concerns of bulk power transfer to the existing 800 MVA limit at the Arrowhead substation and the only now intervening party supporting retention of the 800 MVA export limitation. The Public Utility Commissioners, Commission and DER staff, and utility parties attorneys' are all new to this. ATC did not even exist during the Minnesota EQB hearing – it was not formed until the very end of the first Wisconsin hearing.

History matters. In the initial Arrowhead-Weston project hearing both in Minnesota and Wisconsin, the Arrowhead transmission line was presented as the be-all and end-all of transmission, predicated on the June 25, 1998 blackout extending over most of the Eastern Interconnect, triggering the WIREs and WRAO reports, the result of which the A-W line was selected out of many possible transmission lines to address “the problem.” During the Wisconsin hearing most, if not all, witnesses were asked at the outset of their testimony, “Where were you on the night of June 25, 1998?” with much histrionics, statements that without the Arrowhead-Weston transmission line, we’d have blackouts, hospitals would be without electricity, we’d “freeze in the dark” “in an incubator/on a respirator” and “without a job.” Use of the June 25, 1998 blackout was disingenuous at best, because the MAPP study<sup>5</sup> showed that it was NSP operator “error,” failure to acknowledge warnings, failure to decrease bulk power transfers 300 MW over the operating guide, failure to adhere to MAPP operating guides, all contributing to the largest blackout in the Midwest (see p. iii, 10-15, 19, 24-25... oh, just read it **ALL**! It’s a very informative report.). The blackout was self-inflicted, misrepresented, and misused.

History matters. This Iron Range-St. Louis Co.-Arrowhead 345kV transmission line is the second project where the 800MVA limitation at the Arrowhead substation is being challenged with the aim of removing the limitation<sup>6</sup>. The record does not reflect the circumstances under which ATC dropped its previous effort in the “HVDC Modernization Project” by intervening and hijacking the Minnesota Power project in an attempt to remove the 800 MVA limit. That should be a part of the record. At that time, W.O.L.F. petitioned to intervene to preserve the limit, and was denied.<sup>7</sup> Thankfully, the 800 MVA limitation was not removed in that docket.

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<sup>4</sup> Supra fn. 1.

<sup>5</sup> Attachment B - Northern MAPP Northwestern Disturbance June 25 1998, entered into the record by W.O.L.F.

<sup>6</sup> See PUC Dockets CN-22-607 and TL-22-611.

<sup>7</sup> Denial of W.O.L.F.'s Intervention in PUC Dockets CN-22-607 and TL-22-611 was based on demonstrably false perception regarding W.O.L.F.'s participation and an apparent failure to understand the importance of the 800 MVA limitation. “That matter apparently relates to the present substation at issue. W.O.L.F. claims its contribution to the outcome of the case before the EQB was the requirement that only low-noise transformers be used at the substation.” Not true. Supra Attachment A - W.O.L.F. Initial Brief, WI PSC 05-C#-113.

The cause of the disturbance on June 25, 1998, was a trip of the NSP King-Eau Claire 345kV line at 02:18 CDT along with the prior outage of the Prairie Island-Byron 345kV, which had tripped earlier at 01:34 CDT and could not be reclosed due to a high phase angle across the open breaker. The NSP Operators were focusing on closing the Prairie Island-Byron 345kV line at the time of the subsequent King-Eau Claire 345kV line trip.

The system was in an insecure state following the Prairie Island-Byron 345kV line trip, and not able to withstand the next contingency. The TCEX flow was 1004 MW, and had not been reduced by the NSP System Operators to achieve the safe Operating Guide stability limit of 700 MW prior to the subsequent King-Eau Claire 345kV line trip. Following the King-Eau Claire 345kV trip, the remaining underlying transmission lines out of the Twin Cities area were significantly overloaded and began tripping, and the cascading tripping continued until the entire northern MAPP region was separated from the Eastern Interconnection.

The impact of the disturbance was widespread, affecting the entire MAPP region and the Northwestern Ontario Hydro (OH) system. Northern MAPP separated from the Eastern Interconnection forming several islands, and resulting in the eventual blackout of the Northwestern OH system. In the MAPP region, more than 60 transmission lines tripped, over 4,000 MW of generation was lost, and more than 39,000 customers were affected by the loss of over 300 MW of load. In the Northwestern OH system, all of the tie lines tripped, about 270 MW of generation was lost, and more than 113,000 customers were affected by the loss of 650 MW of load.

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History matters. The basis of the Arrowhead-Weston application was a disingenuous claim that the Arrowhead-Weston project was THE project that would solve our transmission problems.<sup>9</sup>

#### **A. The 800 MVA limit at the Arrowhead substation should remain.**

The Arrowhead Applicants similarly claimed over 25 years ago that the Arrowhead-Weston transmission was needed, and that it would be the one transmission line to address the Midwest's energy transmission issues. That claim proved to be false. Instead, most of the transmission lines proposed in the WRAO report have been permitted and built, despite the claim that the report's 3J, the Arrowhead-Weston line, would solve the Midwest's energy problems.

Today, the same Applicants claim that this ISA project is needed for the "generation transition." That claim, and the "generation transition," has not been demonstrated. The ISA Application has no information of coal plant closures to the west, and instead appears to be building a layer of transmission over the coal plant transmission that's been used over many decades. There's no proof of a "generation transition," only that wind projects have been built. There's no proof that wind is taking the place of coal generation, only that coal generation continues. This is not a "generation transition." The 800 MVA limitation at the Arrowhead substation should remain.

#### **II. Need: Issue of Need requires a Contested Case.**

There are contested issues of fact regarding need that demand a contested case. Primary is that this transmission line is needed or is not needed for "generation transition."

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<sup>8</sup> Supra fn. 5, Attachment B - Northern MAPP Northwestern Disturbance June 25 1998.

<sup>9</sup> See WRAO and WIREs reports, online at <https://legalelectric.org/f/2020/01/WRAO-report1.pdf>

**A. Most importantly, the ISA transmissions line is NOT needed for “generation transition”**

*MISO is not an integrated resource planner, but it is obligated to plan the transmission system in a way that **ensures the energy planned by its members can be reliably and economically delivered** to where it is needed.*

Application, p. 47 (emphasis added). It’s all about delivery, it’s all about market. The MTEP is purely promotional, it’s the MISO Transmission **EXPANSION** Plan.<sup>10</sup> Applicants argue that the 800MVA limitation to bulk power transfer at the Arrowhead substation is not relevant, not needed, is outdated, obsolete, because now it’s all about the “generation transition” and “public policy.” There’s all this wind on the transmission lines, and the 800 MVA limit is contrary to public policy because we need to facilitate the energy transition, so the argument goes:.

- **Generation Transition and Public Policy** – The portfolio alleviates congestion and enables interconnection of approximately 116 GW of new generation resources<sup>46</sup> to meet projected load, public policy objectives, and planning reserve margins. As a result, the portfolio is anticipated to reduce Midwest carbon dioxide (“CO<sub>2</sub>”) emissions by 127 to 199 million metric tons over 20 to 40 years to help states like Minnesota comply with decarbonization laws.<sup>47</sup> In addition to Minnesota, Illinois<sup>48</sup> and Michigan<sup>49</sup> have enforceable decarbonization standards, and Wisconsin<sup>50</sup> has a decarbonization goal. In addition, many Midwest utilities have decarbonization goals.

Application, p. 44. Inarguably, many megawatts of wind generation have been built in the Dakotas. Inarguably, there are many megawatts of fossil generation in the Dakotas. What fossil fuel generation has been shuttered west of this ISA line? How much freed up capacity exists?

Skeptical? Of course. Please prove it. The mantra that this line, the entire MISO Tranche 2.1 transmission buildout, is for “generation transition” is as specious as the “it’s for wind” claim for the Southwest MN 345 kV transmission project a quarter of a century ago, though this is a more modernly finessed extension of the plans for moving coal out of that same area of North Dakota.

It’s not transmission for wind? Yes, that’s demonstrated. Going way back to the beginning, the powerflows from the SW MN 345 kV docket, included in the “Southwest Minnesota - Southeast South Dakota Electric Transmission Study, Phase I: Transmission Outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions<sup>11</sup>,” showed just 213-203 megawatts coming off Buffalo Ridge into the Split Rock to Lakefield Junction line.<sup>12</sup>

That limited wind going into the line is not a surprise, because that Southwest MN 345 kV transmission project was a foundational leg of **Lignite Vision 21**, to bring coal generation from Center and Coal Creek, ND to the Minnesota metro area.

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<sup>10</sup> MISO’s MTEP page: [www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=](http://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=)

<sup>11</sup> Surprisingly, the 2005 pre-CapX 2020 follow up is linked online, not disappeared!  
[www.oasis.oati.com/woa/docs/NSP/NSPdocs/SW\\_MN-TC\\_EHV\\_rpt\\_vol\\_1\\_10-24-05.pdf](http://www.oasis.oati.com/woa/docs/NSP/NSPdocs/SW_MN-TC_EHV_rpt_vol_1_10-24-05.pdf)

<sup>12</sup> Attachment C, Powerflows – See Nobles substation, between Split Rock and Lakefield Junction.





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Why is this important in 2026, twenty-five years later? Why is this important for the Iron Range-St. Louis County-Arrowhead transmission line? Look where the Lignite Vision 21 line begins, and look to the stated purpose, to increase export. That's the same purpose as MISO's Tranche 2.1, and similarly facilitating export from that coal generation area of North Dakota.

In the ISA Application, Section 3.4.1, Applicants provide some background, but make a policy argument for elimination of the 800 MVA limitation omitting crucial facts, particularly regarding coal generation coming into Minnesota from the west<sup>14</sup>.

What coal generation to the west has been shuttered?

#### **Coal generation**

|                   |              |           |
|-------------------|--------------|-----------|
| • Antelope Valley | 954.0        | MW        |
| • Coal Creek      | 1,215.6      | MW        |
| • Coyote          | 450.0        | MW        |
| • Leland Olds     | 656.0        | MW        |
| • Milton Young    | <u>734.0</u> | <u>MW</u> |

**North Dakota Coal: 4,009.6 MW (may be more?)**

How much of this 4,009.6 MW of coal has been shuttered? What has been shuttered frees up capacity. And what's not been shuttered proves the lie of "it's for wind" and is needed for the "generation transition."

#### **Wind generation near the coal**

|              |              |           |
|--------------|--------------|-----------|
| • Baldwin    | 102.4        | MW        |
| • Bison      | 496.8        | MW        |
| • Glen Ullin | 106.7        | MW        |
| • Oliver     | 198.8        | MW        |
| • Sunflower  | <u>104.0</u> | <u>MW</u> |

**North Dakota wind near coal: 1,008.7 MW**

<sup>13</sup> Attachment D, p. 5, Lignite Vision 21 and SW MN 345kV, EQB docket 01-1958. Beginning in the upper left of ap, between Leland Olds, Milton Young, and Coal Creek coal plants, the transmission heads to the southeast, Sioux Falls, the Split Rock substation, and the red part from Split Rock to Lakefield Junction is the SW Minnesota 345 kV.

<sup>14</sup> ISA Combined Application and Appendices A-D, p. 53-43, January 5, 2026, eDockets [20261-226460-03](https://www.ferc.gov/eDockets/20261-226460-03).

How much transmission is needed if they're really shutting down coal plants, 4,000MW of coal in that one area with transmission already crossing the border into Minnesota, and 1,000 MW of wind leaves much capacity for additional wind generation. Looking at the numbers, do we “NEED” this transmission for renewables, to facilitate the renewable energy transition if the coal is shut down?

How many of the 4,009.6 MWs of coal need to be shut down for transmission to accommodate 1,008.7 MW of coal? If the 4000 MW of coal are shut down, logically, there's room for another 3,000 MW of wind. So why the claim of a need for transmission to facilitate the “energy transition?” If there were an “energy transition,” if coal plants were in fact closed, we could logically ship another 3,000 MW of wind over existing transmission.

Additionally, we have the [North Plains Connector](#), an example of a direct current line facilitating coal with new transmission, transmission that connects directly into DC and AC transmission headed into Minnesota, either due east towards the range via CapX 2020 and/or Bison-Alexandria and/or Maple River-Cuyuna CN-25-109/TL-25-110, etc. Here's the Colstrip (coal plant) and Center (coal plant) eastward [North Plains Connector](#):



How does building new transmission and elimination of the 800 MVA limit facilitate the renewable energy transition? What the numbers say is that rather than facilitate the energy transition it enables continued coal generation that's using transmission capacity, rather than open up capacity by closing the coal plants?

## **B. Need – Phased and connected actions, promotional activity – it's all connected.**

Planning is a phased and connected actions: MISO is a marketing organization designed to provide the ability to market electricity from any Point A to any Point B. MTEP, and MISO at its core, is promotional activity. It is crucial to address phased and connected actions and how that is

<sup>15</sup> North Plains Connector, online at [northplainsconnector.com](http://northplainsconnector.com)

used to claim need, because in transmission, “it’s all connected.”<sup>16</sup> The planning timeline for utility infrastructure projects is very long, as is the stretch of regulatory review and construction. For this reason, in looking at need, the projects queuing up need to be considered as a whole.

Cumulative impacts are many, because the MISO plan is so large, and building upon other plans that include thousands of miles of transmission. Each transmission project in the MISO Tranche 2.1, and Tranche 1, MVP 17 Project Portfolio, JTIQ projects, CapX 2020, it’s a long list of cumulative impacts and phased and connected actions. When considered as a whole, is more transmission needed?

Determining “need” for a project and permitting a project when transmission is not available for that project is a (poorly) phased and connected action. The impact of the Public Utilities Commission in Minnesota, and the Public Service Commissions in North and South Dakota, have for decades sited renewable energy in more remote locations without access to transmission. Complaints abound about the MISO queue. This pattern of siting has been intentional, to preserve utilities central station power scheme and to site “renewable” projects quickly without regard for impacts. The Commission made no concerted effort at responsible siting, and has avoided extensive, or better yet, exclusive, use of distributed generation.

Another project linking weighing heavily on need, as a phased and connected action, is the Hermantown Google data center.<sup>17</sup> This data center is much like the Google Pine Island data center, another phased and connected action. The Hermantown data center would be built directly adjacent to the Arrowhead substation and plans to connect directly into the Arrowhead substation. The impact on the need for the ISA of a large load user next to the new substation must be addressed.



<sup>16</sup> Testimony of NSP’s Don Jones, circa 2000 in the first Wisconsin Arrowhead-Weston transmission project, PSC docket 05-CE-113: “Hypothetically if the line came close to anywhere, it might be connected.” Arrowhead I, Tr. at 5913; It’s possible if you connected them, they would be connected.” Id., Valine, Tr. at 6747.

<sup>17</sup> See Minnesota Power/Harmony Google ESA, PUC Docket M-26-159.

<sup>18</sup> Application, Appendix G, p. 34 of 34, with “Data Center Here” written in.

The Hermantown data center could not be a more obvious example of a phased and connected action. The impacts of this phased and connected action are extreme, particularly with the planned active heavy industrial nature of a data center placed in a residential rural or exurban community with the passive electric infrastructure that's been present for years. A change of that magnitude must be considered – it would not be there but for the St. Louis Co. and Arrowhead substations. There's the impact of the power demand, the very amount of the power demand, has a tremendous impact on energy needs, community, landowners, water resources, and noise. Without ready transmission and ready energy supply, the Hermantown data center won't be built.

**C. Need – Peak demand has been grossly overestimated over the years and the Applicants' peak demand forecast is impossible to determine**

CapX 2020's 2005 peak demand forecast should be a wake up call to the Commission. Was it?

**Study overview**

In developing this long-range plan for major new construction, the CapX 2020 technical team considered two potential scenarios for growth in electricity demand:

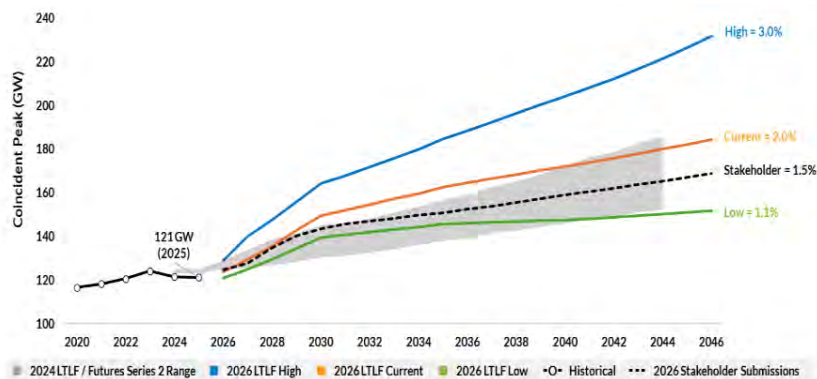
1. Anticipated load growth of 2.49 percent annually from 2009 through 2020, for an increase of 6,300 megawatts. This is based on load projections for utilities with customers in Minnesota, published by the Mid-Continent Area Power Pool (MAPP) in the 2004 MAPP Load and Capability Report and in recent utility resource plan filings. Load growth of 6,300 MW would require over 8000 MW of new generation, given losses that occur when transmitting electricity, electric service to generation stations, and planning reserve margins of 15 percent to ensure reliability.

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MISO continues this bizarrely high demand forecast, claiming data center build-out as a major cause. Here we go again!

Most of this growth is driven by rapid data center expansion supporting AI and digital services, along with increased manufacturing activity influenced by federal-related incentives.

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The Applicants peak demand forecast over the last 20 years is impossible to determine from the application, and they're exempted from providing that information in the ISA Application. The

<sup>19</sup> CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs, May 2020, online at: [legalelectric.org/f/2025/04/5-11-05-CapX2020-Tech-Update.pdf](https://legalelectric.org/f/2025/04/5-11-05-CapX2020-Tech-Update.pdf). Note that due to losses, MISO admits that 8,000MW of generation is necessary to deliver 6,300 MW – this is acceptable? How inefficient can we be?

<sup>20</sup> MISO Long Term Forecast, p. 1, May 2026: [cdn.misoenergy.org/20260513%20LTLF%20Whitepaper757916.pdf](https://cdn.misoenergy.org/20260513%20LTLF%20Whitepaper757916.pdf)

<sup>21</sup> Id., p. 3.



information is either not present or is protected behind a veil of confidential, trade secret, or another type of category of information hidden from the public. From the application:

Minnesota Power's most recent peak demand and annual forecast may be found in Minnesota Power's 2025 Annual Electric Utility Forecast Report filed on August 1, 2025,<sup>98</sup> which is provided in Appendix K.

ATC's load forecast information is set forth in Table 17.

Table 17. ATC 10-Year Load Forecast Information

| Year | Gross Load (MW) | 2024-2034 Compounded Annual Growth Rate |
|------|-----------------|-----------------------------------------|
| 2024 | 12,744          | -                                       |
| 2034 | 15,990          | 2.3%                                    |

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Is “gross load” the same as “peak demand?” Minnesota Power’s forecast error:

Figure 20: AFR Forecast Accuracy – Aggregate System Energy

Total Energy Sales Forecast Error

|          | 2000  | 2001  | 2002  | 2003 | 2004  | 2005  | 2006  | 2007  | 2008  | 2009   | 2010   | 2011  | 2012  | 2013  | 2014  | 2015  | 2016  | 2017  | 2018  | 2019   | 2020  | 2021  | 2022  | 2023  | 2024 |
|----------|-------|-------|-------|------|-------|-------|-------|-------|-------|--------|--------|-------|-------|-------|-------|-------|-------|-------|-------|--------|-------|-------|-------|-------|------|
| AFR 2000 | -3.9% | 1.5%  | 0.5%  | 1.0% | -0.6% | -2.2% | -2.7% | -3.7% | 20.1% | 1.0%   | -5.1%  | -6.0% | -3.5% | -3.4% |       |       |       |       |       |        |       |       |       |       |      |
| AFR 2001 |       | -2.0% | 0.3%  | 3.4% | -1.0% | -3.1% | -4.1% | -3.9% | -4.2% | 28.0%  | 0.5%   | -4.2% | -4.4% | -3.1% | -3.3% | 6.4%  |       |       |       |        |       |       |       |       |      |
| AFR 2002 |       |       | -0.9% | 3.1% | 0.2%  | -2.4% | -3.8% | -4.4% | 28.2% | -0.4%  | -5.4%  | -5.0% | -5.5% | 3.6%  | 5.8%  |       |       |       |       |        |       |       |       |       |      |
| AFR 2003 |       |       |       | 3.6% | -1.8% | -2.9% | -2.9% | -2.1% | -2.7% | 31.6%  | 2.8%   | -1.3% | -0.9% | 2.0%  | 3.2%  | 15.2% | 18.8% | 12.5% |       |        |       |       |       |       |      |
| AFR 2004 |       |       |       |      | 0.6%  | -0.3% | -0.5% | 0.0%  | 0.6%  | 36.1%  | 6.4%   | 2.4%  | 3.0%  | 6.0%  | 7.5%  | 20.1% | 25.2% | 17.7% | 20.0% |        |       |       |       |       |      |
| AFR 2005 |       |       |       |      |       | -0.3% | -0.5% | 0.6%  | 4.1%  | 41.5%  | 11.0%  | 6.8%  | 7.0%  | 10.2% | 11.7% | 24.6% | 29.9% | 21.8% | 23.9% | 27.7%  |       |       |       |       |      |
| AFR 2006 |       |       |       |      |       |       | -0.3% | 1.4%  | 1.8%  | 41.8%  | 11.1%  | 7.4%  | 8.0%  | 10.0% | 10.5% | 22.3% | 26.2% | 17.2% | 17.0% | 20.9%  | 38.1% |       |       |       |      |
| AFR 2007 |       |       |       |      |       |       | 0.0%  | -0.5% | 37.0% | 6.0%   | 2.8%   | 3.4%  | 5.7%  | 6.0%  | 17.4% | 21.0% | 12.3% | 12.0% | 15.3% | 31.6%  | 18.6% |       |       |       |      |
| AFR 2008 |       |       |       |      |       |       |       | -2.0% | 34.8% | 8.9%   | 5.1%   | 4.0%  | 4.8%  | 4.1%  | 15.6% | 19.3% | 11.2% | 12.4% | 15.2% | 32.1%  | 19.5% | 26.0% |       |       |      |
| AFR 2009 |       |       |       |      |       |       |       |       | 4.8%  | -16.8% | -13.9% | -8.1% | -3.1% | -0.9% | 11.0% | 15.0% | 8.5%  | 10.2% | 13.4% | 30.2%  | 17.5% | 24.3% | 22.8% |       |      |
| AFR 2010 |       |       |       |      |       |       |       |       |       | -0.8%  | -1.8%  | -1.0% | 0.7%  | 1.1%  | 11.6% | 15.2% | 6.9%  | 7.7%  | 10.1% | 28.1%  | 13.8% | 20.5% | 19.2% | 21.3% |      |
| AFR 2011 |       |       |       |      |       |       |       |       |       |        | -0.3%  | -1.1% | 0.5%  | 1.0%  | 11.9% | 16.7% | 7.5%  | 8.4%  | 10.8% | 26.9%  | 14.4% | 21.0% | 19.7% | 21.7% |      |
| AFR 2012 |       |       |       |      |       |       |       |       |       |        |        | -1.4% | 0.5%  | 0.7%  | 11.5% | 15.4% | 6.9%  | 7.8%  | 10.2% | 28.4%  | 13.9% | 20.5% | 19.2% | 21.4% |      |
| AFR 2013 |       |       |       |      |       |       |       |       |       |        |        |       | -0.2% | 2.4%  | 18.1% | 24.6% | 18.7% | 20.8% | 22.6% | 40.2%  | 28.2% | 33.4% | 31.7% | 33.8% |      |
| AFR 2014 |       |       |       |      |       |       |       |       |       |        |        |       |       | -0.3% | 13.9% | 24.2% | 13.9% | 14.9% | 17.2% | 34.0%  | 20.3% | 27.0% | 25.3% | 27.0% |      |
| AFR 2015 |       |       |       |      |       |       |       |       |       |        |        |       |       |       | 2.4%  | 5.9%  | 9.9%  | 11.0% | 13.1% | 29.4%  | 18.3% | 22.9% | 20.9% | 22.5% |      |
| AFR 2016 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       | -1.4% | -4.3% | -2.9% | -2.2% | 20.4%  | 10.1% | 18.3% | 17.0% | 18.8% |      |
| AFR 2017 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       | 1.8%  | 2.5%  | 3.6%  | 24.2%  | 13.1% | 19.3% | 17.8% | 19.7% |      |
| AFR 2018 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       | 1.4%  | 1.7%  | 20.4%  | 9.7%  | 16.7% | 15.1% | 16.8% |      |
| AFR 2019 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       |       | -1.8% | 14.7%  | 4.2%  | 12.1% | 12.0% | 13.7% |      |
| AFR 2020 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       |       |       | -15.7% | -7.8% | -2.2% | -4.0% | -2.9% |      |
| AFR 2021 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       |       |       |        | -8.7% | -2.7% | -2.9% | -1.3% |      |
| AFR 2022 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       |       |       |        |       | -1.2% | -0.9% | 0.5%  |      |
| AFR 2023 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       |       |       |        |       |       | -4.4% | -4.5% |      |
| AFR 2024 |       |       |       |      |       |       |       |       |       |        |        |       |       |       |       |       |       |       |       |        |       |       |       | 0.3%  |      |

N.n% = Year-Ahead Forecast N.n% = Current Year Forecast N.n% = 5 Year-Ahead Forecast

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<sup>22</sup> Application, p. 71.

Figure 21: AFR Forecast Accuracy – Summer Peak

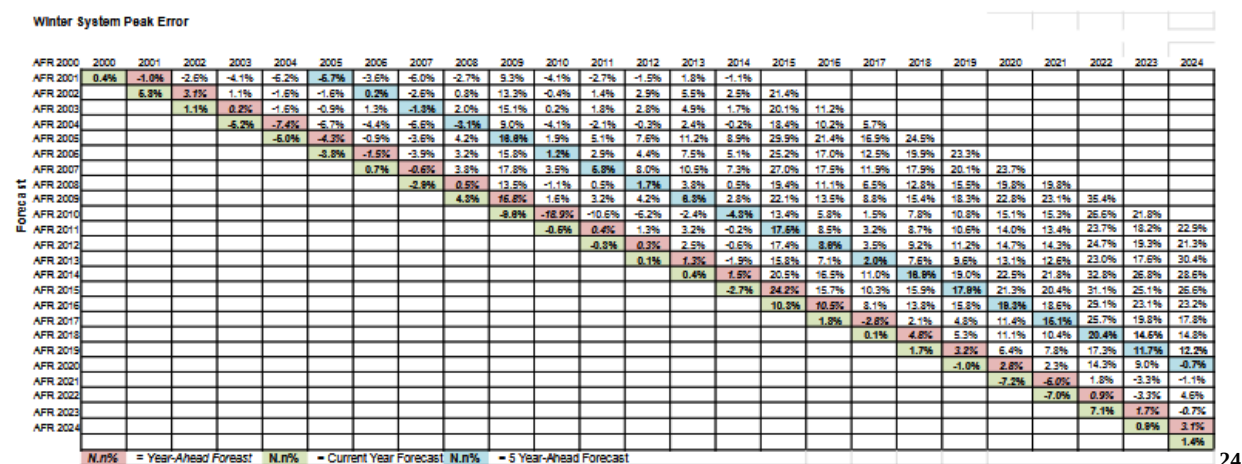
Summer System Peak Error

|          | 2000 | 2001                  | 2002  | 2003  | 2004  | 2005  | 2006                    | 2007  | 2008  | 2009  | 2010   | 2011                    | 2012   | 2013  | 2014  | 2015  | 2016  | 2017  | 2018  | 2019  | 2020   | 2021  | 2022  | 2023  | 2024  |
|----------|------|-----------------------|-------|-------|-------|-------|-------------------------|-------|-------|-------|--------|-------------------------|--------|-------|-------|-------|-------|-------|-------|-------|--------|-------|-------|-------|-------|
| AFR 2000 | 0.9% | 13.7%                 | -5.5% | -1.3% | -3.1% | -6.8% | -5.5%                   | -7.5% | -3.1% | 23.6% | -2.2%  | -1.6%                   | -2.8%  | -0.2% | -0.1% |       |       |       |       |       |        |       |       |       |       |
| AFR 2001 |      | 5.2%                  |       |       |       | -4.8% | -3.8%                   | 0.5%  | 28.0% | 1.4%  | 2.4%   | 1.2%                    | 2.5%   |       | 17.4% |       |       |       |       |       |        |       |       |       |       |
| AFR 2002 |      |                       | -2.0% | 5.0%  | 3.5%  | -0.6% | -2.6%                   | -1.9% | 2.3%  | 30.7% | 2.4%   | 3.1%                    | 1.4%   | 2.7%  | 2.3%  | 16.7% | 16.9% |       |       |       |        |       |       |       |       |
| AFR 2003 |      |                       |       | 2.4%  |       | -4.4% | -6.4%                   | -8.2% | -3.1% | 24.6% | -2.9%  | -1.7%                   | -2.2%  | -1.7% | -2.0% | 12.4% | 12.0% | 7.5%  |       |       |        |       |       |       |       |
| AFR 2004 |      |                       |       |       | 0.0%  | 0.0%  | -3.9%                   | -3.5% | 3.7%  | 30.8% | 1.7%   | 4.8%                    | 4.1%   | 5.6%  | 6.3%  | 22.5% | 22.7% | 18.4% |       |       |        |       |       |       |       |
| AFR 2005 |      |                       |       |       |       | -5.0% | -8.9%                   | -6.3% | 3.1%  | 30.7% | 2.5%   | 3.3%                    | 2.0%   | 4.4%  | 5.2%  | 21.3% | 22.8% | 19.2% | 19.1% | 25.6% |        |       |       |       |       |
| AFR 2006 |      |                       |       |       |       |       | -0.2%                   | -0.7% | 4.5%  | 34.3% | 5.9%   | 7.0%                    | 6.0%   | 7.5%  | 7.0%  | 22.0% | 22.0% | 17.1% | 15.2% | 20.0% | 35.2%  |       |       |       |       |
| AFR 2007 |      |                       |       |       |       |       |                         | -2.4% | 2.5%  | 31.4% | 3.5%   | 4.8%                    | 3.6%   | 5.2%  | 5.0%  | 19.8% | 19.8% | 15.1% | 13.4% | 18.1% | 33.4%  | 23.0% |       |       |       |
| AFR 2008 |      |                       |       |       |       |       |                         |       | 2.5%  | 31.0% | 3.2%   | 3.7%                    | 2.4%   | 3.6%  | 2.9%  | 17.3% | 17.4% | 12.9% | 11.6% | 16.3% | 31.6%  | 21.6% | 30.2% |       |       |
| AFR 2009 |      |                       |       |       |       |       |                         |       |       | 0.0%  | -27.1% | -15.6%                  | -11.9% | -6.9% | -8.2% | 5.3%  | 5.7%  | 2.0%  | 1.1%  | 6.1%  | 20.9%  | 12.2% | 20.5% | 16.0% |       |
| AFR 2010 |      |                       |       |       |       |       |                         |       |       |       | -0.1%  | -1.4%                   | -2.6%  | -1.5% | -2.1% | 11.3% | 11.2% | 6.7%  | 5.1%  | 9.3%  | 23.4%  | 13.6% | 21.2% | 15.8% | 20.4% |
| AFR 2011 |      |                       |       |       |       |       |                         |       |       |       |        | -1.5%                   | -3.5%  | -2.4% | -2.8% | 10.8% | 10.8% | 6.3%  | 4.9%  | 9.2%  | 23.3%  | 13.6% | 21.2% | 15.8% | 19.3% |
| AFR 2012 |      |                       |       |       |       |       |                         |       |       |       |        |                         | -3.7%  | -3.0% | -4.5% | 8.8%  | 8.9%  | 4.9%  | 3.1%  | 7.3%  | 21.2%  | 11.7% | 19.3% | 14.1% | 19.4% |
| AFR 2013 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        | -2.8% |       |       |       |       |       | 13.5% | 18.0%  | 32.9% | 22.2% | 30.2% | 24.2% |
| AFR 2014 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       | -4.3% | 13.2% | 19.5% | 14.9% | 13.3% | 17.6% | 32.5%  | 21.6% | 29.3% | 23.2% | 27.7% |
| AFR 2015 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       | 1.0%  | 5.4%  | 10.6% | 10.6% | 14.9% | 29.4%  | 18.9% | 26.4% | 20.6% | 26.6% |
| AFR 2016 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       | -1.4% | 7.0%  | 0.0%  | 1.6%  | 24.0%  | 16.2% | 23.9% | 18.3% | 23.9% |
| AFR 2017 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       | 4.5%  | 2.2%  | 4.0%  | 20.0%  | 11.1% | 18.1% | 12.9% | 21.5% |
| AFR 2018 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       | 0.6%  | 15.4% | 7.6%   | 14.8% | 8.7%  | 16.1% |       |
| AFR 2019 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       |       | -1.1% | 11.4%  | 3.2%  | 12.1% | 7.6%  | 12.7% |
| AFR 2020 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       |       |       | -17.7% | -4.8% | 1.3%  | -3.9% | 10.7% |
| AFR 2021 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       |       |       |        | -6.3% | 0.8%  | -3.8% | -1.8% |
| AFR 2022 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       |       |       |        |       | 8.9%  | 1.2%  | -1.4% |
| AFR 2023 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       |       |       |        |       |       |       | -2.2% |
| AFR 2024 |      |                       |       |       |       |       |                         |       |       |       |        |                         |        |       |       |       |       |       |       |       |        |       |       |       | -1.5% |
|          | N.n% | = Year-Ahead Forecast |       |       |       | N.n%  | = Current Year Forecast |       |       |       | N.n%   | = 5 Year-Ahead Forecast |        |       |       |       |       |       |       |       |        |       |       |       |       |

N.n% = Year-Ahead Forecast N.n% = Current Year Forecast N.n% = 5 Year-Ahead Forecast

<sup>23</sup> Application, Appendix K, p. 30-31 of 297 (emphasis added).

**Figure 22: AFR Forecast Accuracy – Winter Peak**



Minnesota Power readily admits the potential for large load customers, such as the Google data center in Hermantown:

However, a fully econometric process would not reflect any of the substantial industrial expansions that are **likely** in the Minnesota Power service territory. A combined “econometric/large customer load addition” approach produces the most reasonable forecast.<sup>25</sup>

MISO insists that data centers were not a consideration in development of MISO’s Tranche 2.1, and at the Commission meeting but those statements are not credible. Utilities initiated tariff changes, proposals, long before data centers were visible on our horizon.

#### **D. Need -- Cost Increase of the ISA Transmission Project requires Variance Review**

It appears that the Iron Range-St. Louis-Arrowhead transmission project has had enough of a cost increase to trigger a MISO Variance Analysis. When the ISA project was approved by MISO, the total cost was estimated to be \$428 million. On March 30, 2026, MISO released an updated cost estimate for each project in Tranche 2.1. As of that date, the cost of the ISA project is now \$499 million. What is the cost today?

| ID | Project Name                                          | Predominate kV | Targeted ISD | Est. Cost (\$M, 2024) |
|----|-------------------------------------------------------|----------------|--------------|-----------------------|
| 19 | Bison- Alexandria                                     | 345            | 2032         | \$216                 |
| 20 | Maple River- Cuyuna                                   | 345            | 2033         | \$908                 |
| 21 | Iron Range - Arrowhead                                | 345            | 2032         | \$428                 |
| 22 | Big Stone South- Brookings County- Lakefield Junction | 765            | 2034         | \$1,459               |
| 23 | Lakefield Junction- East Adair                        | 765            | 2034         | \$1,375               |
| 24 | Lakefield Junction- Pleasant Valley- North Rochester  | 765            | 2034         | \$1,195               |

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<sup>24</sup> Id.

<sup>25</sup> Id., p. 31-32.

<sup>26</sup> MTEP24, p. 162 – 2024 cost.



Since the time of the MISO Board’s approval of Tranche 2.1 in MTEP 2024, costs have risen sharply, and what’s interesting is that the projects where the cost as changed are in Minnesota! For the others, the cost has either not changed, risen a most nominal amount, or even decreased.

Updated: 03/31/2026

Multi-Value Project Dashboard  
Tranche 2.1 Portfolio

WOLF Attachment D - Multi-Value Project Dashboard

| #     | Project Name                                                       | State    | MTEP Approval | Current Date | State Regulatory Status | Cost    | MTEP Approval (2024) | Q4 2025 (2024) Value Added | Notes                     |
|-------|--------------------------------------------------------------------|----------|---------------|--------------|-------------------------|---------|----------------------|----------------------------|---------------------------|
| 15    | Bison - Alexandria                                                 | MIN ND   | 2032          | 2032         | ●                       | \$216   | \$237*               |                            | Cost change under review. |
| 16    | Maple River - Cuyuna                                               | MIN ND   | 2033          | 2033         | ●                       | \$908   | \$1,037*             |                            |                           |
| 18    | Iron Range - Arrowhead                                             | MIN SD   | 2032          | 2032         | ●                       | \$499   | \$499                |                            |                           |
| 19    | Big Stone South - Brookings County - Lakefield Junction            | MIN SD   | 2034          | 2034         | ●                       | \$1,459 | \$1,739*             |                            |                           |
| 22    | Lakefield Junction - East Adair                                    | IA MN    | 2034          | 2034         | ●                       | \$1,375 | \$1,398*             |                            |                           |
| 24    | Lakefield Junction - Pleasant Valley - North Rochester             | MN       | 2034          | 2034         | ●                       | \$1,105 | \$1,050*             |                            | Cost change under review. |
| 25    | Pleasant Valley - North Rochester - Hampton Corner                 | MN       | 2032          | 2032         | ●                       | \$222   | \$241*               |                            |                           |
| 26    | North Rochester - Columbia                                         | MIN WI   | 2034          | 2034         | ●                       | \$1,324 | \$1,873*             |                            |                           |
| 27    | Rocky Run - Werner - North Appleton                                | WI       | 2032          | 2032         | ○                       | \$212   | \$212                |                            |                           |
| 28    | South Fond du Lac - Rockdale - Big Bend - Sugar Creek - Kitty Hawk | WI       | 2033          | 2033         | ○                       | \$1,102 | \$1,102              |                            |                           |
| 29    | Bluemound - Arcadian - Waukesha - Muskego - Elm Road - Racine      | WI       | 2032          | 2032         | ○                       | \$731   | \$731                |                            |                           |
| 30    | Columbia - Sugar Creek                                             | WI       | 2034          | 2034         | ○                       | \$743   | \$686                |                            |                           |
| 31    | Sugar Creek - Collins                                              | IL WI    | 2034          | 2034         | ○                       | \$733   | \$807                |                            |                           |
| 32    | Ludington - Denver - Tishawassawee & Nelson Road                   | IN       | 2032          | 2032         | ○                       | \$1,363 | \$1,033              |                            |                           |
| 33    | Greenlawn - Spencer - Lula                                         | MO IA    | 2033          | 2033         | ○                       | \$1,310 | \$1,310              |                            |                           |
| 34    | Onida - Siltone Lake - Blackfoot & Majestic                        | IN       | 2032          | 2032         | ○                       | \$659   | \$659                |                            |                           |
| 35    | Southwest Indiana-Kentucky                                         | MO KY    | 2032          | 2032         | ○                       | \$743   | \$748*               |                            |                           |
| 36    | Southeast Indiana                                                  | MO OH    | 2032          | 2032         | ○                       | \$578   | \$578                |                            |                           |
| 37    | Maywood - Belleau - MRPD - Sioux - Bugle                           | IL MO    | 2032          | 2032         | ○                       | \$881   | \$881                |                            |                           |
| 38    | East Adair - Marshalltown - Sub T                                  | IA       | 2034          | 2034         | ○                       | \$1,583 | \$1,583              |                            |                           |
| 39    | Lehigh - Marshalltown - Franklin North & Montezuma                 | IA       | 2032          | 2032         | ○                       | \$588   | \$588                |                            |                           |
| 40    | Sub T - Woodford County - Collins & Reynolds                       | IA IL IN | 2034          | 2034         | ○                       | \$2,228 | \$2,228              |                            |                           |
| 41    | Woodford County - Fargo & Redbourn                                 | IL       | 2032          | 2032         | ○                       | \$412   | \$412                |                            |                           |
| 42    | Blum Oak - Schaller                                                | IN       | 2032          | 2032         | ○                       | \$68    | \$68                 |                            |                           |
| Total |                                                                    |          |               |              |                         |         | \$31,848             | \$33,314                   |                           |

\*Some or all facilities reported in nominal (year of occurrence) dollars.

In addition to the Tranche 1 Northern Reliability Project, two Tranche 2.1 projects are labeled as “cost change under review.” At this time, it’s not known whether the “review” is a MISO Variance Analysis.

The charts above reflect the cost for the full ISA transmission project. However, the project does include some infrastructure in Wisconsin and it is unclear whether the Wisconsin parts of this project are covered by the ISA project application. Apparently, for only the Minnesota part:

The original scoping cost estimate used by MISO for review of the Project as part of the LRTP Tranche 2.1 Portfolio and the cost basis upon which it was approved by the MISO Board of Directors in December 2024 is \$370.1 million (2024\$).<sup>13</sup>

ISA Application, p. 22. Applicant’s claim that the cost approved by MISO, at \$370.1 million, again, for only the Minnesota portion and Superior infrastructure is inconsistent with the MTEP cost estimates and makes no sense. Further, if the cost approved was \$370.1 million, and now the cost is \$499 million, this project is overdue for a MISO Variance Analysis.

**Table 3. Current Project Cost Estimates**

| Project Component                                                                        | Mid (\$ Millions) (2024\$) | High (\$ Millions) (2024\$) |
|------------------------------------------------------------------------------------------|----------------------------|-----------------------------|
| Iron Range – St Louis County 345 kV Single-Circuit on Double-Circuit Capable Structures* | \$370.0                    | \$425.5                     |
| St. Louis County – Arrowhead 345 kV Double-Circuit                                       | \$12.0                     | \$13.8                      |
| Iron Range Substation Expansion                                                          | \$7.2                      | \$9.4                       |
| St. Louis County Substation Expansion                                                    | \$31.4                     | \$40.9                      |
| ATC Arrowhead Substation Expansion <sup>14</sup>                                         | \$16.3                     | \$21.3                      |
| Existing 230 kV Line Modifications                                                       | \$4.2                      | \$4.9                       |
| Existing 500 kV Line Crossing Modifications                                              | \$3.0                      | \$3.5                       |
| <b>Project Cost Totals</b>                                                               | <b>\$444.1</b>             | <b>\$519.3</b>              |

\* Including stringing the second circuit and operating initially at 230 kV in Segment 2.

<sup>27</sup> Attachment E, MISO Multi-Value Project Dashboard, online: [cdn.misoenergy.org/Tranche%202.1%20Dashboard732078.pdf?v=20251215144025](https://cdn.misoenergy.org/Tranche%202.1%20Dashboard732078.pdf?v=20251215144025)

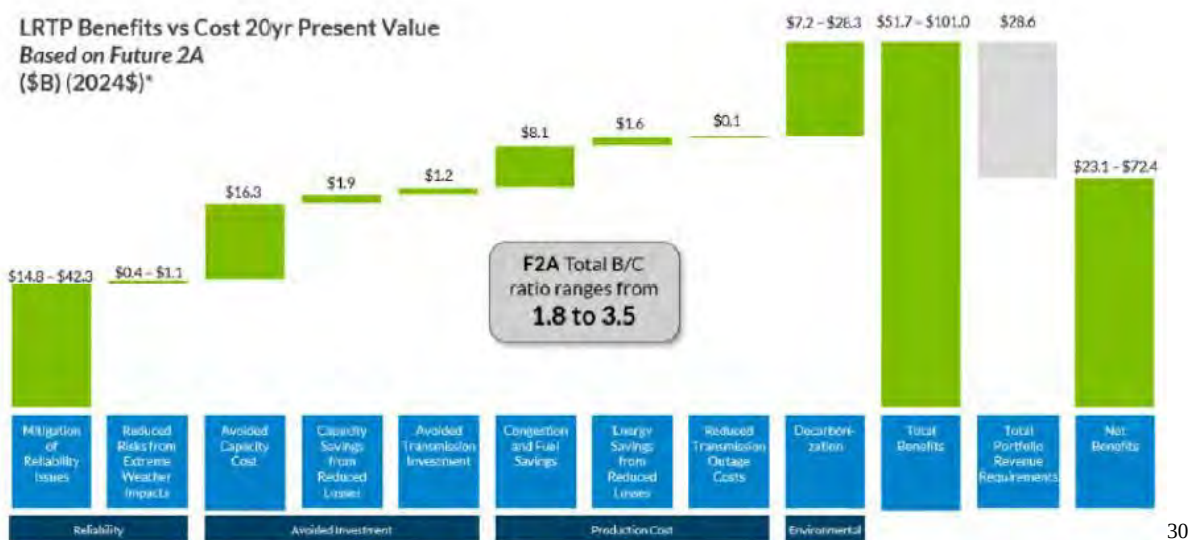
The original all-inclusive MISO estimate was \$428 million, as above. Applicant claims that the 2024 original cost was estimated at \$370.1 million (?), and the current project cost total ranges between \$444.1-519.3 million, an increase of \$74-149.2 million from that \$370.1 million. MISO states the cost estimate is now \$499 million.

Where a project increases 25% or more, MISO embarks on a “Variance Analysis.” From the numbers provided by the Applicant, ISA project cost has risen over 25% and this project is due for a Variance Analysis. Two Tranche 2.1 projects are admittedly in a “review process,” #19, the Bison-Alexandria line, and #25, the Lakefield-Pleasant Valley-North Rochester line. In addition, costs have risen for Tranche 1 projects, including Minnesota Power’s Northland Reliability Project, also the subject of a MISO Variability Analysis.<sup>29</sup>

#### E. Need – Where costs increase, the cost/benefit analysis is no longer valid

A Variance Analysis addresses significant cost increases. What’s the process to assess benefits? The cost/benefit analysis for the projects of Tranche 2.1 was performed in 2023, using 2023 costs, and approved by MISO in 2024. Benefits claimed are:

**Figure 14. Economic Savings from the MISO LRTP Tranche 2.1 Portfolio<sup>59</sup>**



Note that while MISO claims these as “benefits,” Applicants more accurately refers to them as “economic savings.” Also worth noting is that these economic savings accrue to the members of MISO, not ratepayers.

However much has changed since 2023, our economic landscape is now scorched earth. Costs have risen, and the cost/benefit analysis must be performed once again because the resulting ratio is no longer valid.

<sup>28</sup> Id.

<sup>29</sup> See i.e., the Northland Reliability Project, PUC dockets CN-22-415 and TL-22-416.

<sup>30</sup> Application, p. 27.

### **G. Need – Minnesota needs to ask, “MISO, what have you done for me lately?”**

This is a Minnesota Certificate of Need docket, where the Applicants have the burden of proof and must prove that this project is needed as defined by our Minnesota Certificate of Need statute. Despite this requirement, despite this burden of proof, there is no basis in the Application for a determination of “benefits” to Minnesota as most of the “benefits” are not based on the utility applicants, instead determined on a zonal basis or load ratio share, and, again, the benefits accrue to the corporate members of MISO.

| <b>Benefit Metric</b>                      | <b>Allocation Method</b>                           |
|--------------------------------------------|----------------------------------------------------|
| Avoided Capacity Costs                     | Determined based on load ratio share               |
| Capacity Savings from Reduced Losses       | Determined based on load ratio share               |
| Congestion and Fuel Savings                | Determined by zone based on PROMOD results         |
| Reduced Transmission Outage Costs          | Determined by zone based on PROMOD results         |
| Energy Savings from Reduced Losses         | Determined by zone based on PROMOD results         |
| Reduced Risks from Extreme Weather Impacts | Determined based on load ratio share               |
| Avoided Transmission Investment            | Determined by zone based on location of upgrade    |
| Mitigation of Reliability Issues           | Determined by zone based on location of violations |
| Decarbonization                            | Determined based on load ratio share               |

Figure 37 - Table of distribution of benefits

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There is no reliable source of information separating out benefits to Minnesota, for this project or any of the Tranche 2.1 projects. The Iron Range-St. Louis County-Arrowhead Transmission Project, in concert with the prior MISO transmission buildouts, has made Minnesota mostly a transmission pass-through. For the Iron Range-St. Louis County-Arrowhead transmission Project, the ATC ask for removal of the 800 MVA limitation is a factor in this conclusion of Minnesota as a pass-through.

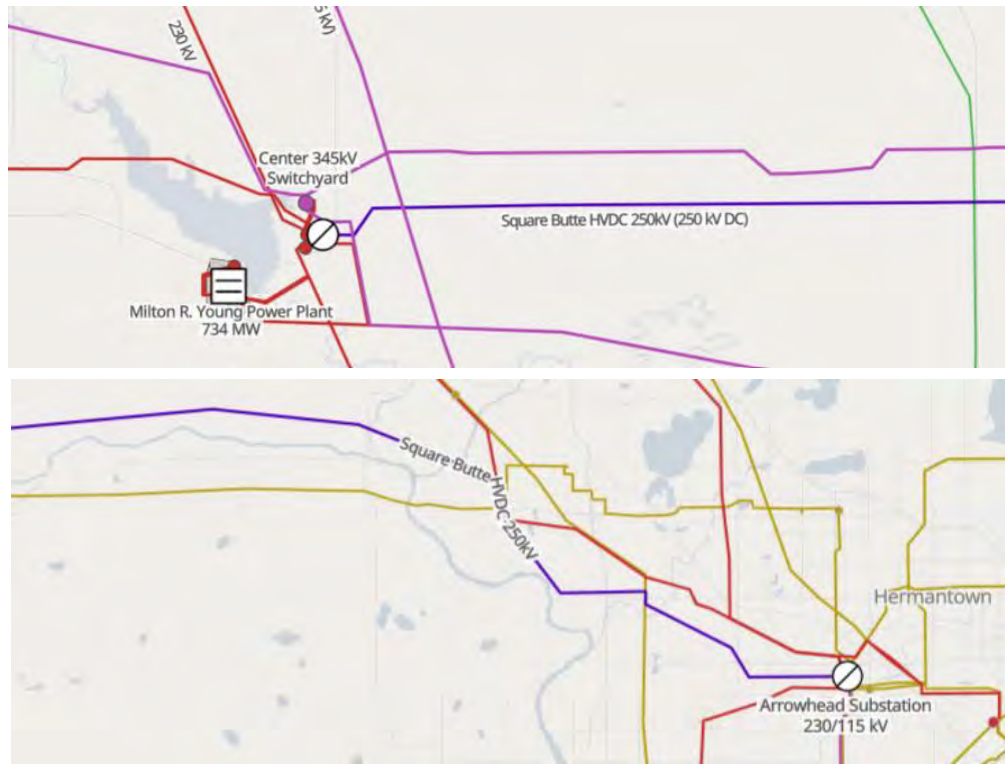
### **III. System Alternatives to be considered in the Environmental Report and Certificate of Need determination**

#### **A. System Alternative - Direct current lines export from the eastern end of the North Plains Connector head to Minnesota’s Metro and via Iron Range substation into the Arrowhead substation**

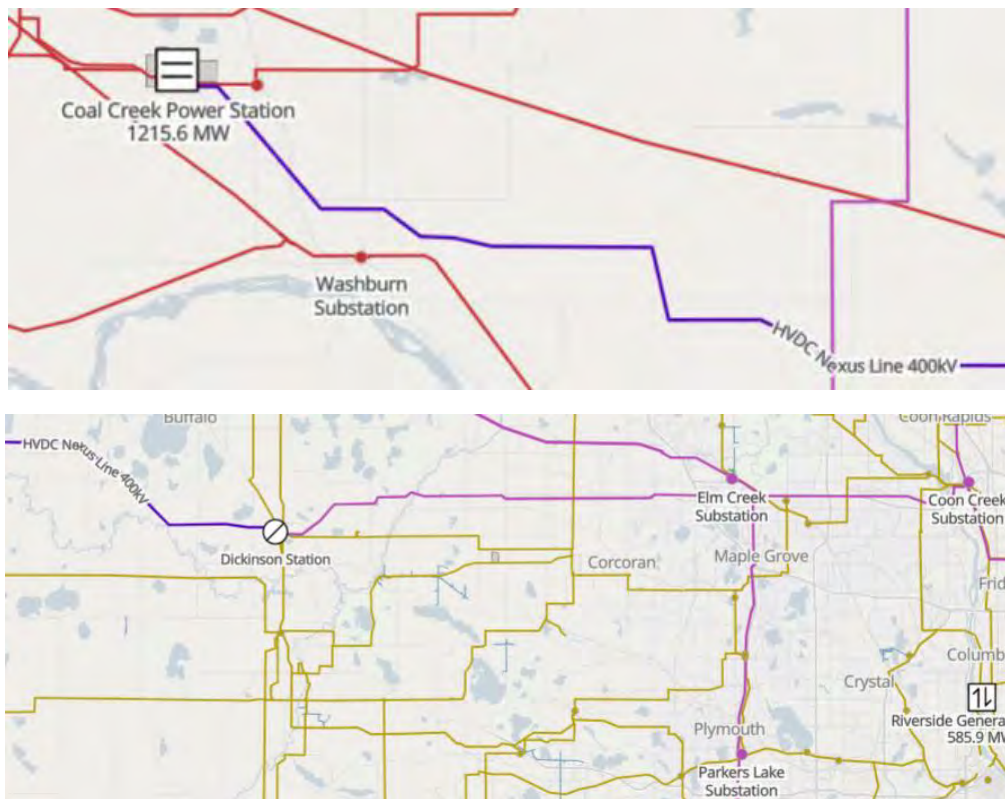
The Square Butte direct current transmission line starts at Center, ND, and then to the Arrowhead substation (Open Infrastructure, i.e. [openinframap.org/#9.31/47.2121/-101.1661](https://openinframap.org/#9.31/47.2121/-101.1661)):

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<sup>31</sup> MISO’s Business Case Metrics Methodology Whitepaper:  
[cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf](https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf)



To the north, at Coal Creek, the Nexus 400 kV direct current line runs to Dickinson Station, just north of Delano, where it's converted to AC and heads to the Metro:

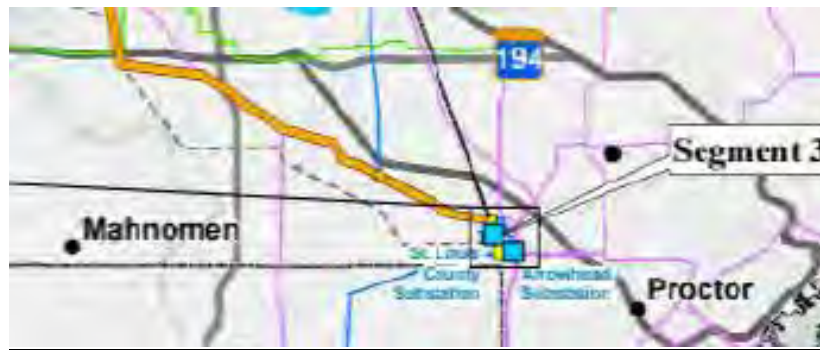




### **B. System Alternative – Close coal plants and free up more capacity**

This is a simple concept -- if Tranche 2.1 is to further the “generation transition,” the logical next step is to close the coal plants, free up capacity, and figure out where we are. If the coal plants are not closed, building new transmission in the area is merely adding additional transmission on top of existing transmission, enabling the continued export of coal underlying renewable development.

### **C. System Alternative – Direct current from North Dakota to Arrowhead via Iron Range, and underground Segment 2 east of Highway 33 to Arrowhead substation converters.**



Transmission lines will logically have more objections and objectors as it approaches larger towns and cities. The logical place to start undergrounding is where population increases. The cost savings of eliminating objections is hard to measure but quantifiable, and this cost savings should be investigated and included in environmental review and the Certificate of Need case.

### **D. System Alternative – 525kV direct current can provide 3,000 amp capacity**

The Application states that MISO design for the Tranche 2.1 requires a 3,000 amp capacity:

- The 345 kV transmission line conductor must be capable of carrying 3,000 amperes (“amps”) per the MISO project definition.<sup>32</sup>
- The 345 kV transmission line conductor must be capable of carrying 3,000 amps per the MISO project definition.<sup>33</sup>

Direct current begins the transmission journey from generation to the west and brings it into Minnesota. Direct current brings energy into the Arrowhead substation. It makes no sense to convert to alternating current in the middle of the transmission journey. Coincidentally, the recently announced “North Plains Connector,” heading from Montana through North Dakota towards Minnesota is another direct current transmission line:

Within the NorthernGrid planning area, an independent transmission company is

<sup>32</sup> Application, p. 19, **2.1.4 Transmission Structures and Conductor Design**

<sup>33</sup> Application, p. 87, **4.8 ALTERNATIVE NUMBER, SIZE, AND TYPE OF CONDUCTOR**

developing North Plains Connector (NPC), which is a planned 525 kV HVDC line with 3,000 MW capacity to connect the Western Interconnection and Eastern Interconnection between Colstrip, Montana, and North Dakota.<sup>34</sup>

Carrying through with direct current makes the most electrical and economic sense.

**E. System Alternative – AC transmission heading east towards Minnesota needs upgrading**

The arguments above are not to say that existing transmission does not need upgrading, because it does. On a recent trip to Little Missouri State Park, through much of North Dakota, most transmission was single circuit 345kV lines built decades ago, a need in plain sight. These old single circuit transmission lines heading east need upgrading, not just a 2<sup>nd</sup> circuit, but modern conductor and structures as well. In the hundreds of miles in, around, and out of North Dakota, I saw only one bundled transmission line -- most were single circuit on weathered aging H-frames.

For example, from the Center/Coal Creek area, some of the lines in need of rehab and/or upgrading due to age and low capacity are:

- Garrison-Jamestown, a 230 kV single circuit line
- Center-Mandan, another 230 kV single circuit line
- Leland Olds – Groton, a single circuit 345 kV line
- Center-Maple River, another single circuit 345 kV line, “ending” where the MISO Tranche 2.1 Maple River – Cuyuna 345 kV “begins”(CN-25-109 and TL-25-110).



<sup>34</sup> DOE’s National Transmission Needs Study Draft for Consultation and Public Comment, released July, 2026, p. 73, online at [www.energy.gov/documents/national-transmission-needs-study-draft-july-2026](https://www.energy.gov/documents/national-transmission-needs-study-draft-july-2026) See below, fn. 33.

Upgrading the AC system west of the Arrowhead substation, particularly in North Dakota, to utilize modern conductors, using bundled or twisted pair, upgrading the transmission structures, would likely double the capacity. Updating the current lines would eliminate need for most, if not all, new transmission projects on the Range. How hard is that?

Upgrading the existing transmission lines west to east across the Dakotas and northern Minnesota to at least 345kV (if AC) and 525kV(if DC) would provide much, if not all, of MISO's "needed" 3,000 MW capacity demand.

Why not upgrade? Is it a matter of the difference in return on investment for upgrading versus new transmission? Is it a matter of cost allocation and ability to foist costs elsewhere? Utilities do have a responsibility to rehab, repair, replace elements of the system and are not keeping up.

#### **F. System alternative – Direct current is more efficient due to lower line loss.**

Alternating current is inherently inefficient when compared with direct current. How many homes and businesses could be powered by avoiding the line loss that use of direct current would provide? MISO requires 3,000 amps – how much additional generation is needed to reach that 3,000 amps? It's no secret that direct current has a much lower percentage of line loss, and the longer a line is, the greater the line loss.

Transmission applications no longer reveal the percentage of line loss of each individual line, i.e., it's in the record that the Xcel line from Lyon County to Sherco (to save Xcel's "valuable transmission interconnection rights") is 11-12%. That number could likely be assumed for any other AC line of 180 miles or so. A line twice that long would have greater line loss. Is it additive or ?? **The applicants must disclose the line loss for this specific project.** The megawatts of additional generation needed to assure the desired number of electrons arrive at the other end of the line is an important fact to consider in permitting of any transmission line.

Wind and solar have lower capacity factor than coal or nuclear generation. If the wind, totaling 1,008.7 MW, were shipped over direct current lines, there would be significant savings, i.e., no need for an inverter at generation sites to convert DC to AC, and elimination of line loss of at least 11% or more over long distances would mean that 100-150 MW more would be received at the end of the line. Transmitting a resource with capacity factor of 25-41% over long distances with 11% or more line loss makes zero sense. Continued use of inefficient AC for shipping renewable energy is inexplicable and unacceptable.

Reactive power and/or series compensation needed due to line loss in alternating current and not present in direct current must also be factored in, and the cost must be considered.

The area of this transmission project utilizes direct current transmission, and Minnesota Power is a utility utilizing direct current, a utility with experience with direct current and infrastructure in place, particularly after its "HVDC Modernization Project." This "HVDC Modernization Project" prepares the area for even more direct current transmission.

Preparing the area for more direct current is a good idea, because there's a new direct current

project in Montana and North Dakota, located either due east towards the range via CapX 2020 and/or Bison-Alexandria and/or Maple River-Cuyuna CN-25-109/TL-25-110, etc.

Again, here's the long direct current transmission line proposed between Colstrip (coal plant) and Center (coal plant) eastward [North Plains Connector](#):



35

MISO is supposedly looking at direct current for integration into future transmission build-out:

HVDC stakeholders have requested MISO prioritize initiatives related to HVDC facilities, as reflected in the MISO Dashboard issues [MSC-2024-8](#) (Incorporating HVDC in Energy and Ancillary Services Market Operations, as well as Transmission Planning) and [RASC-2024-5](#) (Capacity Accreditation for External Resources facilitated by HVDC Transmission). During the April 29, 2025, [HVDC Assessment Workshop](#), MISO and stakeholders identified key questions to define the focus areas for the 2025 impact assessment.

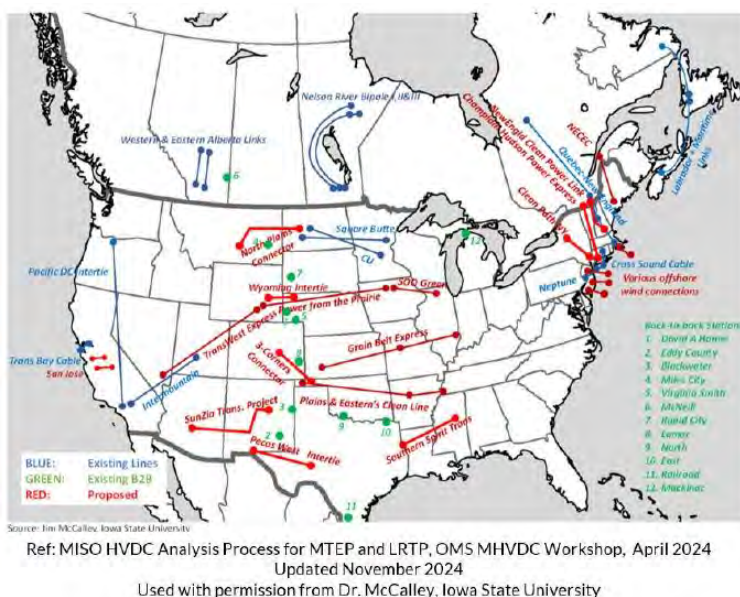


Figure 1: Existing and Planned HVDC in the United States and Canada

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<sup>35</sup> North Plains Connector, online at [northplainsconnector.com](http://northplainsconnector.com)

<sup>36</sup> Attachment F, MISO's 2025 HVDC Impact Assessment, p. 4.



Even Clean Grid Alliance is on the bandwagon for DC, having made a presentation at a MISO subcommittee meeting in May. WOW! An Information Request has been made, and we're waiting on tenterhooks. The Commission can and should look into MISO's DC subcommittee and DC inquiry, Clean Grid Alliance's role, and proceed with integrating HVDC lines.

**G. System Alternative – Direct current UNDERGROUND eliminates objections.**

A very important point for W.O.L.F. is that use of underground direct current would eliminate nearly every objection raised to transmission, essentially it would eliminate all but the objections focused on enabling continued reliance on central station generation! Other than an ongoing objection to use of alternating current which locks us into use of central station power, name one objection that remains if buried Direct Current were used...

**H. System Alternative - Distributed generation, using variable fuel options, storage, and Demand Side Management – the cheapest option available -- these are the most logical solution to at least some and likely all our “energy problems”**

As a system alternative, the Commission must consider the depth and breadth of \$21 billion of distributed generation and demand side management. Or at least “just” Minnesota's portion of the Tranche 2.1 cost, at least \$6 billion, and likely much more.

The impact of the practice of the Public Utilities Commission of Minnesota, and the Public Service Commissions in North and South Dakota, which for decades have sited renewable energy in relatively remote locations without access to transmission, is now upon us. Complaints abound about the MISO queue. The point of this pattern of ineffective siting industry wide has been to avoid distributed generation. This avoidance serves to preserve utilities central station power scheme. Failure to utilize significant megawatts of distributed generation and DSM result in a manufactured “need” for transmission. That “need” is heightened if coal is not shut down, where coal exports continue, because transmission capacity isn't freed up with closing of coal.

How much distributed generation, from solar to batteries, could we install for the \$22 billion of MISO's Tranche 2.1? Each MISO build-out, from CapX 2020, to MVP, to Tranche 1, and now Tranche 2.1, further entrenches us into the central station model, more and more reliant on long distance expensive transmission – expensive in dollars, building excess generation to make up for line loss, and societal costs.

As long as utilities, and MISO, are determining our energy needs based on its central station model focused on transmission **expansion** model, we'll continue to “need” more and more transmission. It's time to focus on the most cost effective and efficient means of electrifying the Midwest. It's time to get serious about distributed generation, using variable fuel options, storage, and demand side management,

**I. System Alternative – Corridor shared with highways and the new law**

The Minnesota legislature has passed provisions to encourage transmission in Rights of Way and has required coordination. This is a system alternative because it is much more than determining

a route. This also requires a mindset shift in planning, moving away from MISO determinations of the purpose of transmission and what is best for Minnesota.

Subd. 4. **High voltage transmission; placement in right-of-way.** (a) For purposes of this subdivision and subdivisions 5 to 7, "high voltage transmission line" has the meaning given in section [216I.02, subdivision 8](#).

(b) Notwithstanding subdivision 1, paragraph (a), high voltage transmission lines under the laws of this state or the ordinance of any city or county may be constructed, placed, or maintained across or along any trunk highway, including an interstate highway and a trunk highway that is an expressway or a freeway, except as deemed necessary by the commissioner of transportation to protect public safety or ensure the proper function of the trunk highway system.

(c) If the commissioner denies a high voltage electric line colocation request, the reasons for the denial must be submitted for review within 90 days of the commissioner's denial to the chairs and ranking minority members of the legislative committees with jurisdiction over energy and transportation, the Public Utilities Commission executive secretary, and the commissioner of commerce.

Subd. 5. **High voltage transmission; coordination required.** Upon written request, the commissioner must engage in coordination activities with a utility or transmission line developer to review requested highway corridors for potential permitted locations for transmission lines. The commissioner must assign a project coordinator within 30 days of receiving the written request. The commissioner must share all known plans with affected utilities or transmission line developers on potential future projects in the highway corridor if the potential highway project impacts the placement or siting of high voltage transmission lines.

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Minn. Stat. §161.45.

What are MISO, utilities, and the Minnesota DOT doing to place transmission in highway right-of-way?<sup>37</sup> In light of the DOT's Policy of Accommodation, there are many restrictions – has this changed on the advent of this new legislation?

The DOT's records of "coordination" must be entered into the record and considered both in environmental review and the substantive Certificate of Need case. Has the Commission procured records of the coordination for this transmission project? What has the Commission done to stimulate and incentivize compliance with the new law by both Applicants and the DOT??

**J. System Alternative – As low capacity factor generation, wind and solar should logically be transmitted using direct current, to avoid the costs of back and forth conversion and to lower line loss that would further reduce efficiency.**

Wind and solar have lower capacity factors than fossil and nuclear. Transmitting wind and solar generated energy over lengthy AC lines is extremely inefficient, because energy is lost at each conversion from DC to AC, and AC has much higher line loss, which further reduces the all-in capacity factor. Wind and solar should be gathered and transmitted using direct current, saving on conversion inefficiencies and line loss. This is not complicated. Calls for transmission for renewable generation should be paired with calls for direct current transmission.

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<sup>37</sup> Attachment G – NextGen Highways Feasibility Study for the Department of Transportation

#### **IV. Procedure – A Contested Case is necessary. No Certificate of Need 345kV transmission project should utilize an “informal” process**

This Iron Range-St. Louis County-Arrowhead 345 kV Transmission Project has been assigned to the “Standard” process route permitting track. However, the Certificate of Need has improperly been assigned to utilize an “informal” process consisting of Comments and Replies. This is absurd for a 345kV transmission, particularly one with so many contested issues surrounding need, system alternatives, and the 800 MVA limitation at the Arrowhead substation. Contested issues include:

- **The 800 MVA limitation** at the Arrowhead substation should remain – W.O.L.F.’s primary concern. Conclusory statements that it is obsolete are not a sufficient justification.
- **Need**
  - The ISA transmission line is NOT needed for “generation transition”
  - Need – Phased and connected actions, promotional activity – it’s all connected
  - Need – Peak demand has been grossly overestimated over the years and the Applicants’ peak demand forecast is impossible to determine
  - Need -- Cost Increase of the ISA Transmission Project requires Variance Review
  - Need – Where costs increase, the cost/benefit analysis is no longer valid
  - Need – Minnesota needs to question “MISO, what have you done for me lately?”
- **System Alternatives** to be considered in the Environmental Report
  - Direct current lines from the eastern end of the [North Plains Connector](#) head to Minnesota’s Metro and via Iron Range substation into the Arrowhead substation
  - Close coal plants and free up more capacity
  - Direct current from North Dakota to Arrowhead via Iron Range, and underground Segment 2 east of Highway 33 to Arrowhead substation converters.
  - 525 kV direct current can provide 3,000 amp capacity
  - AC transmission heading east towards Minnesota needs upgrading
  - Direct current is more efficient due to lower line loss.
  - Direct current UNDERGROUND eliminates objections.
  - Distributed generation, using variable fuel options, storage, and Demand Side Management, as the cheapest option available, are the most logical solution to at least some and likely all our “energy problems”
  - Corridor shared with highway rights-of way

Requests for a contested case may be made at any time prior to the end of the public comment period, but this request is submitted now – the earlier the better so as not to delay the process.

#### **Conclusion**

At this time, W.O.L.F. requests a contested case for the Certificate of Need to address need and system alternatives and the 800 MVA limitation at the Arrowhead substation. This comment is not all inclusive – with a 345 kV transmission line application, there are many issues generally to

address and many specific to this project. An informal “Comment and Reply” process is inadequate to build a record that would support any decision by the Commission. A contested case is required.

It’s our hope that any issues that have been missed will be picked up by other Commentors.

Thank you for the opportunity to file this Initial Comment.

Very truly yours,

A handwritten signature in cursive script that reads "Carol A. Overland".

Carol A. Overland  
Attorney at Law

cc: Linda Hanson, World Organization for Landowner Freedom



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

In the Matter of Iron Range - St.  
Louis County – Arrowhead 345 kV  
Transmission Project

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**CERTIFICATE OF SERVICE**

**INITIAL NEED COMMENT  
WORLD ORGANIZATION FOR LANDOWNER FREEDOM**

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I, Carol A. Overland, hereby certify that I have this day served a true and correct copy of the attached World Organization for Landowner Freedom (W.O.L.F.) Initial Need Comment to all persons at the email addresses on the Public Utilities Commission eDockets service list by eFiling and eService.



July 13, 2026

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# **World Organization for Landowner Freedom**

## **Exhibits**

Attachment A\_A-W#1 Initial WI Brief.pdf

Attachment B\_Northern MAPP Northwestern Ontario Disturbance June 25 1988 FINAL REPORT.pdf

Attachment C\_Powerflows\_SW MN 345kV EQB 01-1958 Powerflow at Nobles.pdf

Attachment D\_Transmission Study - Phase II - Final - 3-14-2001 - LigniteVision1ransmissionstudyII.pdf

Attachment E\_Cost Increase\_Tranche 2.1 Dashboard732078.pdf

Attachment F\_2025 HVDC Impact Assessment.pdf

Attachment G\_NexGen-Highways-Analysis-Report-2.1.24.pdf



**THE  
PUBLIC SERVICE COMMISSION  
OF WISCONSIN**

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Joint Application of Minnesota  
Power Company and Wisconsin  
Public Service Corporation for  
Authority to Construct and Place  
in Service Electric Transmission  
Lines and Other Electric Facilities  
for the Arrowhead-Weston Project,  
Located in St. Louis County in  
Minnesota and Chippewa, Clark  
Douglas, Lincoln, Marathon, Oneida,  
Price, Rusk, Sawyer, Taylor and  
Washburn Counties in Wisconsin.

**Docket No. 05-CE-113**

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**INITIAL BRIEF OF INTERVENOR  
WORLD ORGANIZATION FOR LANDOWNER FREEDOM (W.O.L.F.)**

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**I. INTRODUCTION**

Applicants Wisconsin Public Service Corporation and Minnesota Power have submitted this application for a 345 kV powerline running from the Arrowhead substation in Minnesota to the Weston substation in Wisconsin. Both applicants are public service corporations, which, among other things, grants them monopoly status and presents an opportunity for recovery of costs in rates and use of eminent domain in exchange for an obligation to serve their native load. Wisconsin Public Service Corporation (hereinafter "WPS") is a public service corporation organized under the laws of the state of Wisconsin. Wisc. Stat. §200.01(2). Minnesota Power (hereinafter "MP") is a public service corporation organized under the laws of the state of

Minnesota.

Both Wisconsin Public Service Corporation and Minnesota Power have chosen to make this application under their public service corporations and not as an unregulated corporation. Each has had representatives testify in the Minnesota and Wisconsin proceedings to the corporations' willingness to avail themselves of the benefits of their public service corporation status, such as using eminent domain to complete this project. Because this application is made under the aegis of public service, the corporations must demonstrate that the project is in the public interest, that it is needed, and that it provides benefits to the state of Wisconsin. This has not been shown. The record of this proceeding shows that the only demonstrated benefit of this line is to the applicants, whose goal is to put "more wire in the air," and to whatever entity ultimately has control over and receives profit from the line.

The law of Wisconsin governing siting of powerlines sets out criteria about which the Commission must make determinations, and the application shall be approved only if many determinations are made. Wisc. Stat. §196.491(3)(d) ,et seq. Through the ten thousand page transcript and the 383 exhibits comprising the record, the applicants have not shown need for this project and there is no basis for a Commission determination that the project is needed. Instead, the record demonstrates that there is no need for the line and that the applicants are satisfying the needs of their customers. The record demonstrates that in their claim of need through their LOLE analysis, the applicants are overstating the reserve margin required and misrepresenting the level of increased capacity needed to meet reserve margin, and that the applicants do not need the line to meet reserve margin



requirements. The record demonstrates that the applicants are basing their claim of need on the probability of the occurrence of a number of impossibly remote scenarios, none of which are an appropriate basis of need for the line. The record demonstrates that the benefits of the line are not reasonable in relation to the cost of the line, primarily because the benefits attributed to the WRAO recommended Plan 3j are not attributable to the Arrowhead-Weston line because it does not include all the required improvements and because the line will not provide the reliability required without upgrade of the Forbes-Arrowhead line which is not included as a part of this project application. The record contains no reliability studies of the Arrowhead-Weston line independent from Plan 3j which are necessary to provide a basis for a finding of need due to reliability problems and the solution of these problems by the line. The record does not contain the cost/benefit analysis mandated by statute which is necessary to provide a basis for a finding that the cost of the line is reasonable in relation to the benefits provided. The record demonstrates that the system outages touted by applicants as justification for the line are only symptoms of utility abuse of the transmission system and flagrant disregard of the limitations of that system, and proof that the utilities are putting their demand for economy transactions before grid security. The record shows that reasonable and comparably inexpensive alternatives to the problems that applicants complain of have not been considered, particularly the low-voltage option, distributed generation and cogeneration, and the benefits of conservation – Wisconsin's hierarchy of generation has been ignored. The record demonstrates that contrary to applicants' claim of need, the line is "needed" less than one day annually, and the purpose of the line is to provide the applicants with the

opportunity for increased economy transactions 364 days annually and to provide the applicants the opportunity to position their corporations beyond their self-described “electrical cul-de-sac” onto the super-highway of bulk power transfer in today’s changing market.

It is not in the public interest to build a powerline at ratepayer and public cost to help corporations pursue market interests. Because this powerline is not in the public interest, it is not appropriate for the applicants to use the regulatory benefits of eminent domain and recovery of costs through the rates to build this line. The record contains no basis for the Commission to grant a Certificate of Public Convenience and Necessity for the Arrowhead-Weston line – the application must be denied.

**II. THE ARROWHEAD-WESTON POWERLINE DOES NOT MEET WISCONSIN’S STATUTORY REQUIREMENTS FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY BECAUSE THERE IS NO UNSATISFIED PUBLIC NEED.**

There is no basis for a finding by the Commission that the proposed powerline satisfies public need. In order to be granted a Certificate of Public Convenience and Necessity, the Commission must make several determinations, including that “[t]he proposed facility satisfies the reasonable needs of the public for an adequate supply of electric energy.” Wisc. Stat. §196.491(3)(d)2. In order for a project to satisfy the reasonable needs of the public for an adequate supply of electricity, there must be unsatisfied reasonable energy needs and the specific project proposed must satisfy those reasonable needs. In this case the energy needs of the public are being adequately met and the needs satisfied with this project are the corporate desires of the utility and not the needs of the public.

The applicants would have the Commission believe there is a “transmission

crisis” of the highest order, but this transmission crisis is a crisis of the utilities’ own making through their desire for increased “market” and “economy” transactions and efforts to move all the power they can sell. Applicants have not provided any analysis or independent studies that justify this project, yet they make unfounded claims of need:

**To suggest that our reliability situation will improve without more wire in the air is wishful thinking.**

Borgard, Surrebuttal, p. 3, Tr. at 3264; Tr. at 3569.

Yet despite these dramatic assertions, the application is devoid of the types of studies and documentation typically found in an application for a transmission line.

There’s a lot we don’t know about the Arrowhead-Weston line, as Applicant’s counsel readily admits:

**We’re talking about permission for the utility to construct. So to the extent that – again, I don’t want to get into a legal argument but it’s silly to ask this witness to sit on the witness stand when we don’t know specifically what lines are going to be constructed.**

**We don’t know where, we don’t know what the proposed voltage is going to be, whether there is going to be an upgrade and argue about whether we might need a CPCN under the circumstances.**

Will, Tr. at 5909 (in objection).

There is no basis for a Commission determination of need for this project because the Applicants overstate need by mischaracterizing WUMS as an electrical island, misapplication of reserve margin requirements, and basing their claimed capacity needs on improbable scenarios, when in fact studies show that the applicants’ electric supply and delivery is meeting customer needs.

**A. RELIABILITY INDICATORS PRESENTED BY APPLICANTS FALSELY OVERSTATE "NEED"**

There is no basis for a Commission finding of need based upon this Application and the proceedings on the record because “need” is demonstrably overstated. See Wisc. Stat. §196.491(3)(d)2. Using a Loss of Load Expectation analysis (LOLE), applicants claim that there is insufficient transfer capacity into WUMS,<sup>1</sup> insufficient to provide for necessary imports to support the reserve margin and insufficient to provide Applicant WPS access to cheap power. Wisconsin’s PSC requires a 18% reserve margin. Ex. 175, WRAO, Attachment C, p. 5. Specifically, they claim that the LOLE set out in the application demonstrates that an additional 834 megawatts transfer capacity is needed in WUMS above the eighteen percent reserve margin for reliability purposes. Ex. 171, Application, Table 7, p. 47, l. 1k; see also WRAO, Attachment C, Wisconsin’s Electric Transmission Interconnection Capacity Requirements, Table C-1, Summary of Results of LOLE Analysis for the EWU.

Applicants’ claims are overstated due to the erroneous assumption that WUMS is an island which requires a 25.1% margin, an increase of 7.1% over non-isolated system, and by incorporating the reserve margin twice where it is already included within firm transactions, resulting in “double-dipping” in their claim of need.

LOLE studies are the most common indicator of system reliability:

Reliability is a probabilistic concept and must be described in terms of probabilities. The most commonly used measurement of power system

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<sup>1</sup> WUMS is the Wisconsin Upper Michigan System, distinct from EUW, the Eastern Utilities of Wisconsin. WUMS’ eastern boundary is Lake Michigan, to the north, Lake Superior, to the south, the Wisconsin/Illinois border, and to the west, somewhere in mid-Wisconsin, where the MAPP and MAIN regions divide Wisconsin.

reliability is LOLE. LOLE is defined as the fraction of time during which electricity demand would be expected to exceed available electric capacity, based on the probabilities associated with electricity demand and generation outages. As generally used, LOLE is a measure of the adequacy of the generation system, and thus does not consider outages due to transmission and distribution system damage, such as that caused by windstorms.

Ex. 222, Report to the Wisconsin Legislature, p. 11. A LOLE analysis can show if there is adequate generation or whether additional capacity, whether through generation or transmission, is required:

LOLE simulations calculate the probability that customer demand will exceed available internal generating capacity and imported generation capability for a specific period of time. The sum of these probabilities over the study period defines the LOLE for the study period. The industry standard for reliability is an LOLE of 1 day in 10 years (or 0.1 day/year). This criterion issued for planning purposes to insure that electric supply exceeds customer demand for a variety of weather conditions and bulk electric system conditions. Thus, if the sum of the probabilities from an LOLE analysis for a 1-year period is less than 0.1, the criterion has been met. If greater than 0.1, additional resources (generation and/or imports) must be added.

Ex. 175, WRAO, Attachment C, p. 5.

Applicants provide additional charts claiming to prove that there is not sufficient transfer capacity to provide the necessary reliability in WUMS, and make the claim that there is often NO transfer capacity available in WUMS. Ex. 181 (CTP-4) WUMS Interfaces Total Transfer Capability graphs; Ex. 183 (CTP-5) WUMS Interfaces Total Transfer Capability graphs; Ex. 184 (CTP-6) WUMS Interfaces Total Transfer Capability graphs.

Primarily, the claims of applicants rest on their application, and the results shown in Ex. 171, Application, Vol. I, Table 7, LOLE Analysis, CT/CC Capacity added. Applicants admit that:

We used 834 megawatts based on table 7 because it represented the

difference between the 18 percent reserve margin and the 25.1 percent reserve margin needed to maintain one day in 10.

Smies, Tr. at 4174. 25.1% is the recommended reserve margin for an area where there are no electrical interconnections. Ex. 222, Report to the Legislature, p. 11. Yet nowhere has it been established that WUMS is an electrical island requiring the 25.1% reserve margin, and in fact, the record shows that WUMS does have existing interconnections to the transmission system and that it is not an electrical island. See Ex. 246, NERC 2000-2009, p. 59. WUMS was characterized by applicants as an electrical “cul de sac,” which is not sufficient to justify construction of a powerline based upon electrical isolation. Plante, Tr. at 3717.

The basis for Applicants’ claim of need is apparent in its explanation of its rejection of new generation and its preference for transmission comes out a few pages later:

According to Table 5 of the Application, this capacity would be used the equivalent of **.92 days/year**. Therefore there is no need to compare the price for purchase power to the price of generation, since the duty cycle for the 834 MW of combustion turbines is so limited. Since both the line and generation option are tied to the same reliability criterion (0.1 day/year), both options are equally exposed to risk of loss of load.

**The investment in generation versus a line for reliability purposes can be thought of as an insurance policy. If the investment is in generation it will only be used once a year. All of the fixed costs associated with generation would have to be collected that limited use. If the investment is in a line, however, that investment will not only serve as an insurance policy, but will give Wisconsin ratepayers access to external markets and the opportunity to take advantage of lower cost sources of energy when they are available.**

Smies, Rebuttal, p. 17, Tr. at 4134 (emphasis added). Simple math reveals that the line may only be “needed” 0.92 days per year, but it will be available for use 364.08 days/year, for increased access to external markets and the opportunity to take



advantage of lower cost sources of energy, all to the applicants' benefit and to the benefit of other utilities in WUMS.

**1. WUMS is not an electrical island requiring a 25.1% reserve margin – the standard 18% is sufficient.**

Applicants shore up their case for increased capacity through a claim that WUMS is an electrical island without interties to the rest of the grid, a situation which requires a greater reserve margin than if it were not an island. If an area is an electrical island, without transmission interties, MAIN encourages a 25.1% reserve margin because it would not have the ability to access to outside generation to either meet its electrical load or reserve margin. Under one definition, absence of an assumption of "a well functioning transmission system allowing the import and export of electric power" the higher reserve margin is necessary. Yet in the LOLE, "the second set of assumptions capped internal generation at presently approved levels and forced shortfalls to be addressed with imports." Landgren, Tr. at 4424. This forced analysis in the WRAO sets up the Applicant's claim that WUMS is an electrical island:

Q:... I believe you testified to Mr. Will that you did regard it as an electrical island; is that correct?

A: Based on the condition of our interface right now and the amount of capacity that's being relied on, yes. p. 4244.

Q: And in order to include that approximately 1200 megawatts in their reserve requirement, what do they need with respect to transmission path?

A: They need a firm transmission path according to the rules.

Q: Based upon Mr. Plante's testimony this morning, does it appear to you that there is a firm transmission path that is perfectly available over the interface?

A: No, it does not.

Q: And what does this mean to you as a generation planner?

A: It means there is some risk of -- associated with the ability to meet your 18 percent reserve requirement.

Q: Is that the electrical island phenomenon?

A: Yes.

Q: And if we were somewhat of an electrical island, what does that mean about the appropriate reserve planning, for planning purposes.

A: If we are an electrical island because of the fact whatever transmission capacity we have is consumed by these purchases, in order to maintain the one day in 10 year criteria, the reserves and EWU should be approximately 25 percent.

Q: And from an LOLE perspective, what does that mean with respect to the Arrowhead-Weston line?

A: The line is the solution to the problem.

Smies, Tr. at 4244. Put more succinctly:

Q: I'd like to confirm your answer to the last question that Ms. Overland asked you concerning your view of whether he - whether WUMS under the current circumstances is more like an electrical island or less like an electrical island in terms of loss of load probability?

A: I believe it's more like an electrical island.

Smies, Tr. at 4245. This "island" fiction seems to have originated with the Report to the Legislature, which based its analysis on several assumptions made without factual basis, for example:

**This LOLE analysis began by assuming eastern Wisconsin to be an electrical island, i.e. without transmission connections to its neighbors...**

Ex. 222, Report to the Legislature, p. 11. But transfer capacity is available even where applicants' graphs show no available capacity:

Q: Does the fact that the weekly firm transfer capability as calculated by MAIN is zero in a given week mean that it is not possible for WUMS utilities to utilize their firm transmission reservations associated with power purchases from the west during that week?

A: If a customer has already obtained transmission service from a transmission service provider, **these values do not mean that he would not be able to utilize that service.**

Plante, Tr. at 4059 (emphasis added); Ex. 183 & 184, WUMS Interfaces Capability Graphs.

According to the PSC staff engineer, the assumption that WUMS is an island is not reasonable:

This is not the only interpretation of Table 7, however, and certainly not the most reasonable one. I believe it does not make sense, when one is determining the size of a hypothetical generation alternative, to assume that no transmission transfer capability exists when this is clearly contrary to the facts.

Leow, Rebuttal, p. 13, Tr. at 5979.

Dr. Rosen and the Commission staff agree that because there is transmission capability, and WUMS is not an island, the applicants' calculation of necessary reserve margin for WUMS is incorrect:

It is also clear from the Application that this estimate was made by assuming no access to external generation resources. That means that the total import capability into eastern Wisconsin would not need to exceed 834 MW by much to maintain adequate reliability standards through 2007 if enough capacity is built in WUMS to meet the 18 percent required reserve margin.

Rosen, Tr. at 5404.

Dr. Rosen appears to be correct that the applicants claim that the 834 MW figure in Table 7 of the application is based on the assumption of no transmission transfer capability to other regions. This is not the only interpretation of Table 7, however, and certainly not the most reasonable one. I believe it does not make sense, when one is determining the size of a hypothetical generation alternative, to assume that no transmission transfer

capability exists when this is clearly contrary to the facts.

Leovy, Rebuttal, p. 13, Tr. at 5979.

The NERC Reliability Assessment published a MAIN self-assessment of reliability that addresses the generation assessment and transmission constraints in WUMS:

...long-term reserve margins for MAIN as a whole are projected to be within or exceed the recommended rate of 17-20% (14.5 to 16.7% capacity margin)...

Ex. 246, NERC 2000-2009, p. 59. No where in the MAIN Regional Self Assessment does it claim that reserve margins must be above 20% anywhere in the region, and it does not set out that WUMS requires a reserve margin of 25.1%. If there were such a need, the MAIN self-assessment for NERC would have documented it either generally or specifically.

Although the system is constrained, it is not isolated, it is not an island, and if the Commission does not permit the Arrowhead line, there is sufficient capacity such that operating guides would allow for adequate transmission capacity:

...Within MAIN, the Wisconsin Upper Michigan Interconnected System (WUMS) import capability is inadequate. The early completion of Commonwealth Edison's Lockport-Lombard (345 kV double circuit) line due to an accelerated construction schedule has improved import capability for MAIN and the WUMS subregion. However, the western (Eau Claire-Arpin 345 kV) interface within the WUMS subregion continues to constrain MAIN and WUMS imports from the west...

For the planning horizon, MAIN expects its transmission to perform adequately if reinforcements are installed as planned... Mitigation plans, including the use of operating guides in MAIN, have been identified to provide acceptable system performance if the planned facilities are not available.

Ex. 246, NERC 2000-2009, p.59. The system improvements or reinforcements planned are the Lockport-Lombard (currently in operation), Oak Creek-Arcadian, Arrowhead-

Weston, and Burnham-Taylor lines, and again, if these reinforcements are not built, adequate system performance will be achieved through operating guides. Id.; see also Miller, Tr. at 4717 (predictions accurate and capacity adequate).

WUMS is not an electrical island. It is a cul-de-sac. An island has no interconnections to the grid system, and WUMS does have interconnections, which although somewhat strained at times, have not resulted in transfer curtailments cutting firm transactions, demonstration that the situation is not a serious problem worthy of such a drastic and expensive "solution" such as the Arrowhead-Weston powerline.

**2. Applicants' LOLE analysis ignores firm purchases for reserve margin included in peak demand resulting in overstatement of need.**

There is no basis for a finding by the Commission that the Arrowhead project is needed as required by Wisc. Stat. §196.491(3)(d)2 because the Applicants' LOLE analysis includes an overstatement of the reserve margin needed by including it first in the peak demand figures, and then a second time in the calculation for LOLE, boosting "requirement to meet LOLE." The applicants also provide charts as additional exhibits claiming to prove that there is not sufficient transfer capacity to provide the necessary reliability in WUMS. The apparent reason for applicants' claim that additional capacity is needed in WUMS has no relation to the reserve margin, which is adequately covered, but is instead that WPS is a WUMS utility desirous of more capacity for "economy transactions" to maximize its profit opportunities. Applicants' eleemosynary demands are not a sufficient basis for a need determination.

The LOLE chart provided in the WRAO and modified for the application states that "Line 1e" represents "Projected Peak Demand Net of Interruptible Loads." Ex. 171, Application, p. 43, 47; . This Peak Demand figure includes reserve margin capacity as firm capacity purchased and "capacity sales and purchases without reserves are called "non-firm..." Ex. 178, Strategic Energy Assessment Report, p. 23; see also Ex. 172, FEIS, Table 2-8 (peak demand includes net purchases with reserves). WPS' Plante testified that the reserve margin is already included in firm capacity figures:

Q: WUMS utilities rely on significant capacity purchases to meet their reserve margins:

A: Yes, that's my understanding.

Q: Is it also your understanding that WUMS utilities must rely on significant firm transmission reservations to deliver this capacity?

A: Yes. In fact, I don't believe that they are allowed to count the capacity towards their reserve margin unless it is on firm transmission service.

Plante, Tr. at 4059. The inclusion of reserve margin transmission in the base case was reiterated:

A: To the extent that they have acquired a transmission service reservation, they would be included in the base case.

Q: ... But to the best of your knowledge do the WUMS utilities acquire longer term transmission service arrangements to insure that they're included in the base case for purposes of meeting their reserve margin requirements?

A: Yes...

Id., Tr. at 4060.

Another WPS witness agrees that reserve margin reservations are included in firm reservations:

Q: Would you agree that during high peak load periods that a significant portion of the transfers from MAPP to WUMS are firm economic purchases with reserves made by WUMS utilities to meet their 18 percent reserve margin? ...

A: Yes.

Smies, Tr. at 4247-8.

Q: Okay. If there is a supply reliability problem in WUMS, would it be an effective solution to drop or bump these firm economic transfers with reserves off the system in order to increase access to power outside of WUMS to address that supply availability problem?

...A: You can't bump them. You have to have them. You have a shortfall.

Smies, Tr. at 4248.

Yet, despite the inclusion of significant purchased firm transmission reservations to cover the reserve margin, already included in Row 1i, the calculation used to determine total generation to get to 0.1 LOLE is:

**Row 1i Minus 118% of Row 1e = Total Gen above 18% to get 0.1 LOLE.**

Ex. 171, Application, p. 47. This formula used to calculate additional capacity needed does not take into account the "significant" firm capacity transfers that constitute the reserve margin -- these "significant" transfers for the reserve margin are being ignored, and by doing that applicants are adding to the capacity above and beyond necessary reserve margin, surreptitiously opening up additional capacity for economy purchases.

The applicants also provide charts as additional exhibits claiming to prove that there is not sufficient transfer capacity to provide the necessary reliability in WUMS. Ex. 181 (CTP-4) WUMS Interfaces Total Transfer Capability graphs; Ex. 183 (CTP-5) WUMS Interfaces Total Transfer Capability graphs; Ex. 184 (CTP-6) WUMS Interfaces



Total Transfer Capability graphs.; see also Ex. 172, FEIS, Table 208 (peak demand includes net purchases with reserves).

The transfer capacity as set out in the LOLE and Transfer Capacity charts is "double dipping," where the utility's reserve margin is calculated into the net capacity figures and then is added again as a multiplier to determine capacity needed for LOLE, in short, added twice. The purpose of the reserve margin is to provide flexibility to handle to a reasonable degree whatever problems may arise, to act as a cushion in those situations where the unexpected occurs. Yet applicants claim that additional transmission capacity is needed "for common cause events as:"

1. Fuel supply disruption – coal/rail strikes, frozen coal, loss of a pipeline, operation of combustion turbines on oil in cold weather.
2. Common cause failure of a plant – loss of fuel handling system results in loss of plant.
3. Plant shutdown due to regulatory problems – NRC requires shutdown of all WI nuclear units for inspection.

If the transmission system is not adequate, these common cause situations are significantly more threatening to the system.

Smies, Dir. P. 17, Tr. at 4111.

Despite applicants desire for "necessary cushion to account for such common cause events," there is no need for additional reserve margin capacity beyond the reserve margin already incorporated into firm demand:

Q: Is it reasonable to assume that the adequate generation – that adequate generation provides a cushion for failures of the transmission system?

A: I believe that's embedded in the 18 percent reserve requirement that we carry.

Smies, Tr. at 4203. The claimed need is already provided for in the reserve margin.

It is not reasonable to expect that firm transfers would be curtailed because  
There has been only one instance where firm transmission was curtailed within  
Applicants' witness' knowledge:

Q: Have firm transmission reservations associated with these firm capacity purchases by WUMS for the reserve margins been curtailed during the time period shown in these figures, again, to the best of your knowledge?

A. I believe there was an incident in 1999, and it was the June incident where we experienced heavy loadings and were having difficulty obtaining relief on the constrained Eau Claire-Arpin interface.

It's not my recollection that firm transactions were cut...

Q: So while there were not curtailments, there were actions taken by Eastern Wisconsin Utilities to insure that all the transactions did take place, the transfers that were scheduled all took place?

A: Yes...

Q: Do you know if firm transmission reservations associated with firm capacity purchases underlying the reserve requirement have ever been curtailed on the western interface?

A. Notwithstanding the redispatched type of relief that we just discussed, I believe there have been situations where a loss of the king – well, a loss of the Eau Claire-Arpin or Arpin to Rocky Run line has resulted in the loss of a contract path between WPS, Wisconsin Electric and Alliant East with NSP. The loss of that contract path required the curtailment of firm transactions that were taking place because of the loss of a contract path.

Q: Is this the only occurrence that you're aware of?

A: To the best of my recollection, yes, the loss of the contract path resulting in the loss of firm transactions are the only things that I can recall at this time.

The applicants overstate their "need" by duplicating reserve margin requirements that are already included in the base case and by claiming additional need for a cushion for common mode events when this is already included in the reserve margin. The record is replete with information that shows that electric supply

and delivery is adequately meeting customer needs. Applicant's "need" that must be addressed by the Commission is only that need necessary to serve their native load and not an inflated need to provide opportunity to make economy transactions.

**B. APPLICANTS' CLAIM OF NEED FOR IMPORT/EXPORT CAPACITY IS AN INAPPROPRIATELY DETERMINISTIC "SOLUTION" FOR POWER SHORTAGES CAUSED BY IMPROBABLE EVENTS.**

There is no basis for a finding by the Commission that there is a dire need for import/export capacity that justifies the Arrowhead powerline, not only because the LOLE figures are unreasonable, but also because the LOLE, which is a probabilistic tool, does not provide a factual basis due to its unreasonable dependence both on false claims or improbable events. Applicants' base their claim of upon the inaccurate attribution of "island status" to WUMS, as above, where it was assumed that any shortfalls would be met by imports, and not additional generation. Landgren, p. 4, Tr. at 4426. "Need" is also based on the very improbable simultaneous occurrence of several historically unusual and chronologically distant events, including strikes, catastrophic pipeline failures, simultaneous nuclear plant outages and absolute dearth of new generation. See e.g., Landgren, Rebuttal, p. 4432; Miller, Dir. p. 14-17, Tr. at 4687-90. As Edgar states:

The Applicants use of uncertain future in-state generation capacity as a potential extraordinary occurrence to justify a new EHV line is unfortunate. It is unfortunate because there is a real issue of whether extraordinary events such as multiple generation outages or abnormal peaks due to extended heat episodes create a need for additional transfer capacity in Wisconsin.

Edgar, Dir. P. 13.

In their deterministic approach, applicants assume the worst case scenario, and do not undertake a probabilistic analysis that weighs the possibilities of

occurrence of the cited events. To do so would demonstrate that these are not valid arguments for need.

A report was completed by the PSC for the governor regarding capacity and which defined the problem, as set out in the Executive Summary, as follows:

Eastern Wisconsin continues to face above-normal risks of power shortages in the event of significant power plant (nuclear or fossil) outages, significant transmission outages, and/or very hot weather until:

- \* Additional generation capacity is added in eastern Wisconsin; and
- \* Substantial additional transmission capacity that will increase the power transfer capability between eastern Wisconsin and other regions is constructed.

Larry Borgard, WPS, Dir. p. 10, Tr. at 3235, quoting Ex. 222, Report to Governor Tommy G. Thompson, Electric Utility Reliability and Regulation in Wisconsin (1997); see also Loock, Rebuttal p. 3, Tr. at 4971. Applicants claim that Wisconsin would be even more dependent on the West for generation:

Canada expands its hydro generation capacity in Manitoba... or new mine mouth coal plants are built in MAPP, a portion of that energy is sold in Chicago or southern MAIN, and there is no reinforcement of the transmission system in Wisconsin, then companies like WPSC may not only be prevented from accessing the competitive new supplier in MAPP and Canada, but WPSC may not even be able to have access to the new plants built in southern Wisconsin because of the transmission limits.<sup>2</sup>

Smies, Tr. at 4112.

The applicants, justifying their project, claim that there is a need for increased import/export capacity in Eastern Wisconsin (WUMS) based upon a 1970's reduction in oil and gas-fired generation during the "1970's fuel crisis" and a coal and rail strike

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<sup>2</sup> Smies fails to note that if energy from Manitoba Hydro or open mouth mines in N.D. is sold to Chicago, if WPSC wants any of that energy, it will have to pay rates

in that same time period, and a scenario of a “catastrophic failure of a pipeline or compressor station resulting in the loss of significant portions of generating capacity” or a major ice storm. Smies, Tr. at 4113-4115. These events are very rare occurrences and not something to be reasonably planned for in consideration of additional generation or transmission capacity. The 1970’s fuel crisis has not been repeated since that time, the rail and coal strike has also not occurred since that time and the original strike was not even of sufficient duration to affect generation prices significantly, and the possibility of a catastrophic pipeline failure is “very remote.” Smies, Id. When asked whether there were “similar events that have since required the widespread redispatch of generation,” the witness knew of no such events. Smies, Tr. at 4204. And when asked whether he could cite to any regulatory or transmission planning guides or directives that require system reliability design to withstand such improbable events, the witness again knew of no such requirements, and reiterated that the less stringent and more reasonable single or double contingency planning is the standard required. Id., Tr. at 4204-5; 4208. PSC staff deemed the probability of these events occurring was low, noting that “it appears that common-mode outages are not likely to have a significant impact on reliability.” Ex. 172, p. 39, see also 35-40. Even applicants admit that any outcome of an LOLE must make adjustments for “real world circumstances.” Plante, Tr. at 4089. Yet they do not make adjustments for real world circumstances in this LOLE analysis.

That was also the finding regarding a repeat of the unusual 1997 simultaneous outages of three nuclear plants, regarded by applicants as a common mode event

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equal to or higher than those of Chicago purchasers.

that justifies construction of the Arrowhead-Weston line:

The unavailability of several large base-load generation units not only reduced the capability of the regional transmission system but also increased the usage of and dependence on the transmission system as power delivery entities purchased replacement energy from distant sources. This situation was most notable in eastern Wisconsin during the spring of 1997 when all three of Wisconsin's nuclear generating units were unavailable.

Ex. 171, Application, p. 10; see also WRAO, Attachment C, p. 4; Ex. 222, Report to the Legislature, p. 1; Ex. 172, FEIS, p. 20; see also Landgren, Tr. at 4422, 4436.;

Benforado, Tr. at 4774; Gustafson, Tr. at 5197; Miller, 4689. When the probability of three simultaneous outages is considered it is unreasonable to assume such an event:

Given the reasons for all three nuclear units in Wisconsin being off-line at the same time in 1997, it currently appears less likely that all three nuclear units will be off at the same time in the future.... This analysis indicates that, in the near future, outage rates of Wisconsin nuclear units are not likely to exceed the levels of 1994-1998.

Ex. 172, FEIS, p. 39.

That conclusion is echoed in the Strategic Energy Assessment:

Wisconsin's nuclear units are currently operating at 97 to 100 percent capacity factors, and the unavailability experienced in 1997 is not expected for the forecast period.

Ex. 178, SEA, p. xviii.

Applicants also assume, improbably, that new generation will not be built, and have made all their calculations based upon that assumption. Ex. 171, App., Table 7, p. 47. This assumption is made despite Municipal Electric Utilities of Wisconsin testimony that MEUW members have developed a consortium to look at new generation and to encourage construction by independent power producers.

Benforado, Tr. at 4771; 4809. Schoengold estimates that new capacity for eastern Wisconsin over the next few years will total 6,380 MW, of which he considers 2,415 MW as having a high probability of being constructed. Schoengold, Dir. p. 15, Tr. at 5238.<sup>3</sup> New generation is planned and is being built. Miller, Tr. at 4719-20.

In testimony, applicants admit that LOLE results must be interpreted carefully, and that:

It would be wrong to use the results of a LOLE study to conclude that Wisconsin should *“either build generation or build the line.”* It is not an *“either/or”* proposition.

Smies, Direct Testimony, p. 22, Tr. at 4116. Despite this admonition, applicants incorrectly use the LOLE results and set this up in an *“either/or”* proposition by considering only transmission and not any of the less costly system alternatives available.

Significant new generation will be built and should be, but has not been considered by Applicants. The level of need assumed by Intervenor is 1560 MW, and PSC-WI staff agrees with this assessment. Smies, Rebuttal, p. 4122; Ex.172, FEIS, p. 142, p. 31-32, Table 205. Applicants admit that 4,190 MW of new generation is planned and that of that 4,190 MW, 1685 MW of generation would be available to WPS. Smies, Direct Testimony, p. 13, Tr. At 4107; see also Ex. 178, Strategic Energy Assessment – Final Report, p. 20-23. The applicants estimation of new generation is over 100 MW beyond the level of need assumed by Intervenor and PSC-WI staff.

Applicants also acknowledge familiarity with many of the planned generation

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<sup>3</sup> This generation has an implicit cost-shifting factor because “it will be built whether or not the Arrowhead-Weston line is built. Thus, the relative cost basis for comparing

plants either announced or under construction. Smies, Tr. at 4227-42313.

A: We have a database that we purchase from Financial Times Energy. And they scour every periodical they can find. And this database will give you a specific list of each and every project. And we have used that list to identify opportunities for ourselves. So we try to keep track of these things.

Q: So you are aware that there are many, many, many?

A Yes, yes.

Smies, Tr. at 4230-31.

Smies was asked specifically:

Q: And do you know how much new generation capacity has been announced in MAIN? ...

A: I can refer you to my rebuttal, page 31, line 5. It starts, currently there is 19,000 megawatts planned for MAIN between 2001 and 2003. And it goes on to say and 11,500 of these megawatts of these additions are in Northern Illinois.

Smies, Tr. at 4192. Simple subtraction shows that 7,500 megawatts of generation is NOT in Northern Illinois, leaving much generation for other parts of MAIN. Schoengold also testified that much new generation is planned and under construction but is not accounted for by the Applicants. Schoengold, Tr. at 5343.

In claiming that much new generation was urgently needed, the applicants also assert that additional reserve margins must be added to cover annual anticipated increases in load:

In my prepared testimony the reserve requirement for the generation option, using AP8 capacity costs, was \$147 to \$175 million more than the transmission line. Assuming that 869 MW of combustion turbine capacity is needed results in the generation option being \$159 to \$187 million more than the line with respect to revenue requirements. Assuming 930 MW of combustion turbine capacity results in the generation option being \$180-\$207

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this generation to the transmission line is zero.” Id., Dir. p. 16, Tr. at 5239.



million more than the line. This adjustment also shows that if the line is not built, additional generation would have to be added equal to 7.1% times the annual increase in EWU load in order to preserve reliability.

Smies, Rebuttal, p. 9, Tr. at 4126 (emphasis added). What Smies does not point out in this demand for increased capacity is that he testified that the annual load growth in EWU is only 2-3%, so by saying that an additional 7.1% of that amount would be needed, the 7.1% representing the difference between 18% reserve margin and 25.1% if WUMS were an island. 7.1% of 2-3% annual growth is only .142-.213%, hardly worth the ink necessary for his prefiled testimony!

The generation capacity shortage claim is based upon the 1997 experience, where three nuclear plants in Wisconsin were off line simultaneously, a highly unusual event by any standard. The reality is far different than the paranoid visions of the Applicants:

More than 3,000 MW of new capacity resources are scheduled to be added within the MAIN Region in 2000. It is expected that net capacity added in 2001 will be even greater than 2000. Given this large increase in capacity, long term reserve margins for MAIN as a whole are projected to be within or exceed the recommended range of 17-20% (14.5-16.7% capacity margin). The majority of planned capacity additions in MAIN are short lead-time combustion turbine peaking units owned by merchant power producers.

MAIN is expected to have adequate installed generating capacity to meet its one-day-in-ten-years criterion (0.1 day or less per year LOLE). This is based on the projected yearly reserve margins for MAIN, an assumed adequate import capability, and the assumption that other Regions carry on average the same level of reserves as MAIN.

Ex. 246, NERC Reliability Assessment, 2000-2009, p. 59. Logically, at least some of this generation will be added in WUMS, and any generation added in MAIN will have an impact on the flow of power in the interconnected system. Yet applicants have not familiarized themselves with new generation as a solution:

Other than the WRAO report, I'm not aware of another report that specifically deals with potential new generation coming on line and addressing transmission constraints.

Plante, Tr. at 4089-90.

The prior NERC report stated that:

More than 8,000 MW of net production capacity resources are expected to be added within the MAIN Region during the next ten years.

Ex. 245, NERC Reliability Assessment, 1999-2008, p. 69. On the other hand, NERC reports that MAPP is expected to have a 5,400 MW capacity shortfall by 2008, and:

MAPP has seen a tremendous increase in power marketing activity resulting from open access and available low cost energy in the Region. This high level of activity has stretched the existing transmission system to its reliability limits to take advantage of market opportunities.

Id., p. 72. Even the applicants agree that a LOLE analysis must reflect reality:

Q: ... you would consider it perhaps appropriate to adjust or look at the outcomes of an LOLE, a loss of load study, to make an adjustment on necessary transfer capacity based on I guess the real world circumstances?

A: Yes.

Plante, Tr. at 4087-8.

Applicants overstate the WUMS transfer capacity issue using what they admit under cross-examination are highly improbable examples of shortages that are so remote in time or unusual and unlikely that they provide no valuable instruction on the true potential of energy shortages. In evaluating a scenario such as that posed by Applicants, it is necessary to examine whether the events cited would occur again. Applicants have not done this analysis, admit the events are improbable, and a

cursory overview of their scenario shows that it has no value in this determination.<sup>4</sup>

There is no basis for a finding of need by the Commission based upon these arguments.

**C. WPS' RELIABILITY INDICES DEMONSTRATE IT IS, IN FACT, DOING A BIT BETTER THAN AVERAGE JOB OF KEEPING THE LIGHTS ON.**

There is no basis for a finding that the Arrowhead project satisfies need because customer need is being adequately satisfied. The best indication whether there is unsatisfied need for energy is the utility's own reporting on satisfaction of the needs of the public for an adequate supply of electric energy. The current level of satisfaction can be assessed through examination of Wisconsin Public Service Corporation's Reliability Indices, reliability calculations routinely kept by utilities. Ex. 207, Wisconsin Public Service Corp. System Reliability Indices: 1990-1999 (SAIDI,

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<sup>4</sup> Overstating their case detracts from applicants credibility much as the hysterical cross of WPS witness Borgard by Sturgeon representing Wisconsin Power & Light Company:

A: The kind of situations that I'm familiar with are folks who are on, for example, oxygen systems, things like that, life support systems and when they don't have energy or electricity to run those systems, they need electricity to run those systems because they are life support.

If we can't provide that or if the lights go out, literally I think that their life is in jeopardy.

Q: Essentially they could die, correct?

A: That's fair.

...

Q: So having reliable electric service can cause health problems perhaps even death and financial damage to people, would you agree with that?

A: Yes.

Borgard, Tr. at 3551-3553. Nowhere in this false hysteria is it acknowledged that hospitals have standby generation and residential outages are caused primarily by distribution systems. See supra part C. \jablonski cross of??? Reliability is built into the system and it is functioning well. Id.

SAIFI, CAIDI).<sup>5</sup>

Upon request of Intervenor W.O.L.F., applicant WPS provided System Reliability Indices over nine years. *Id.*; Borgard at 3409-3411. This table presents the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (Sustained Interruptions) (SAIFI), and the Customer Average Interruption Duration Index (CAIDI), which are the generally accepted indicators of the reliability of the system. Customer Average Interruption Frequency Index (CAIFI) was requested but is not maintained by WPS. Each of the indices is presented both including and excluding major storms for the years 1990 through 1999.

The first column, the SAIDI, "is calculated on an annual basis by taking all of the customer hours of outage and dividing by the total number of customers on the system that you're serving and that you're analyzing." Hamacher, Tr. at 4846. The next column is the CAIDI, which is "calculated for a particular system on an annual basis and you take the total number of customer hours for the year and divide that by the number of customers' outages in that year." Tr. at 4847. "SAIFI is calculated by taking the number of customers outaged and dividing by the number of customers on the system that you're analyzing." *Id.* Each category was calculated including and excluding major storms so that the impact of storms and unusual weather can be easily taken into consideration.<sup>6</sup>

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<sup>5</sup> The SEA reports that the bulk power market generally contributed to system reliability. Ex. 178, SEA, p. 66.

<sup>6</sup> When taking storms into account, a major storm is where there has been extensive mechanical damage to the system, that over 10% of customers in a given area are out of service, and that more than 1% are out of service for more than 24 hours. Tr. at 4848.

The values shown as totals on the chart are reported by the utility to be primarily driven by distribution outages, which are far more frequent than transmission outages, and which account for less than ten percent (10%) of the totals. Hamacher, Tr. at 4848. Plante agrees that "[m]ost outages experienced by customers are the result of distribution failures as opposed to transmission grid failures." Plante, Tr. at 4088. Neither is reliability a generation problem, because "when there are outages that occur, customer outages, they're more likely to be related to transmission and distribution than they are to generation." Schoengold, Tr. at 5367. The distribution system could not be reliable without a reliable transmission system. WPS testified that if the transmission system were not designed as it is to prevent customer outages in the event of single contingencies<sup>7</sup> the share of outages attributable to transmission would be greater. Hamacher, Tr. at 4847.

Overall, the System Reliability Indices provided by WPS demonstrates that WPS is doing a bit better than average job of keeping the lights on. Id. at 4858. Even Applicants understand that it is not "possible to provide for a one hundred percent reliability." Plante, Tr. at 3698. Yet despite the claimed difficulties of providing reliable service, the SAIDI, SAIFI, and CAIDI Reliability Indices demonstrate that customers received electrical service on demand, which demonstrates system adequacy. The system is operating well and the WPS witness agrees that these WPS figures attest to the reliability of the transmission and distribution system in meeting customer

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3. A transmission system is planned to withstand a single contingency, where one line is out and the remainder of the system continues to function, also known as "n-1" criteria.

needs.

Applicants' "need" that must be addressed by the Commission is only that need necessary to serve the applicants' native load and provide necessary reliability benefits and not an applicants' inflated need to provide itself an opportunity to make economy transactions. Based upon the SAIDI, SAIFI, and CAIDI reliability indices, here is no basis for a finding by the Commission that the line is needed based upon a claim by applicants of inability to adequately meet the electricity needs of the public.

**III. THE RELIABILITY BENEFITS OF THE HIGH-VOLTAGE TRANSMISSION ARE NOT REASONABLE IN RELATION TO THE COST OF LINE.**

There is no basis for a finding by the Commission that the proposed Arrowhead powerline provides additional usage, service or increased regional reliability benefits to those in Wisconsin sufficient to justify construction of the resource intensive Arrowhead-Weston line for anticipated use 0.92 days per year, particularly where the statutorily mandated cost benefit analysis, and a least cost analysis, comparing reliability benefits with costs, has not been completed. Under the statute, the Commission must address three pertinent questions regarding reliability. First, are there usage, service or increased regional reliability benefits; second, are there benefits conferred to the wholesale and retail customers or members in Wisconsin; and third, are any benefits conferred reasonable in relation to the cost of the line.

Wisc. Stat. §196.491(3t). In each case, the cost benefit analysis to prove these points has not been undertaken by the Applicants despite the mandate. There is no basis for a determination by the Commission that the design of the project is in the public interest considering the engineering and reliability conferred by the proposed project

because no engineering information, such as electrical performance modeling or analysis, and no reliability studies have been provided. Wisc. Stat. §196.491(3).

The applicants are basing their reliability arguments on the findings of the WIREs and WRAO reports regarding project “3j,” and their belief that system outages provide demonstration of a reliability problem and need for the line. Plan 3j’s reliability benefits are not applicable to the Arrowhead project alone, and the outages listed don’t demonstrate need -- neither argument holds, and there is no basis for a finding by the Commission that this project provides reliability benefits reasonable in relation to the cost of the line. Because the line does not provide distinct reliability or economic benefits to Wisconsin ratepayers or citizens, the line is not in the public interest under the regulatory purview of the Commission, and must not be permitted. The utilities must not, through a CPCN, receive the regulatory benefits and privileges of public service corporations to assist in this project, such as eminent domain or recovery of costs in rates, when the project is not in the public interest.

#### **A. RELIABILITY AND THE COST/BENEFIT ANALYSIS**

A cost benefit analysis is an integral part of review of any project proposed for a Certificate of Public Convenience and Necessity. Wisc. Stat. §196.491(3t). The statute requires:

For a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more, the high-voltage transmission line provides usage, service or increased regional **reliability benefits** to the wholesale and retail customers or members in this state and the benefits of the high-voltage transmission line are reasonable in relation to the **cost** of the high-voltage transmission line.

Id. (emphasis added).

The Commission, as the regulator in a regulated electric environment, has an obligation to investigate and determine the least cost option. Because this application is under the jurisdiction of the PSC, it is by definition regulated and the costs of this project may to some extent be passed along through the rates, a least cost analysis is necessary. Least cost analysis considers not only “the cost of meeting annual peak demand, in isolation, without regard for the economics of meeting demand in other hours of the year,” but also “the most economical mix of resources.” Rosen, Dir. at 54, Tr. at 5461. This is particularly necessary in this case, where the applicants propose to build a powerline for an expected 0.92 day/yr. use. Smies Rebuttal, p. 17, Tr. at 4134. If the Commission proceeds without further investigation and justification of this line, the Commission is abdicating its regulatory duty.

### **1. Reliability Defined**

NERC defines the reliability of the interconnected bulk electric systems in terms of two basic, functional aspects:

1. Adequacy -- the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
2. Security -- the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Ex. 246 (RAR 11), NERC 2000-2009 The Reliability of Bulk Electric Systems in North America, p. 7; see also Ex. 245 (RAR 10), NERC 1999-2008 The Reliability of Bulk Electric Systems in North America, p. 7.

System adequacy suffers under regulatory changes:



Recently the adequacy of the bulk transmission system has been challenged to support the movement of power to unprecedented amounts and in unexpected directions. This is largely the result of the evolution of the electric industry under open transmission access, particularly when the market is trying to supply replacement resources during unplanned generation outages. These changes in the use of the transmission system have called into question the adequacy of the transmission system. While the system is adequate under the traditional definition, the system may not always be able to accommodate desired transfers of electricity in directions and amounts for which it was not designed.

The transmission system is being subjected to flows in magnitudes and directions that have not been studied or for which there is minimal operating experience. New flow patterns result in new facilities being identified as limits to transfers, and transmission loading relief (TLR) procedures have been required in areas not previously subject to overloads to maintain the transmission facilities within operating limits.

Id., p. 34; see also Terhune, Surrebuttal p. 5, Tr. at 4444.

The applicants claim that:

[t]he prevalent economic benefit has been from a reduction in the generation capacity required to maintain electric service under a myriad of operating scenarios.

Ex. 171, Application, Vol. 1, p. 7.

A reduction in the generation capacity required to maintain electric service is a benefit to the ratepayers to the extent that new generation is not constructed, which ratepayers in the service area pay for regardless of the ultimate destination of load. The predominant reliability benefit has accrued from the adequacy of the bulk power system to transfer power from generation stations to load centers and the security of the bulk power system to deliver emergency energy during times of critical system contingencies and high electrical consumption.

Id. However, the applicants readily admit that the claimed beneficial "market driven changes" "have sufficiently eroded such that the ability to maintain reliable electric service is severely compromised." Id. They also readily admit that "[m]arket-based transactions increasingly compete with reliability-based usage for limited

transmission system availability." Id. However, NERC, noting wild price fluctuations in market settings, states that "[t]he adequacy problem will not be solved in the near term by merely converting it into a price problem." Ex. 246, NERC Reliability Assessment, 2000-2008, p. 34.

Another way of looking at need in relation to reliability is to consider the reliability balance of Dr. Rosen:

... Again, the word need does not mean just to improve reliability because as I said in my direct testimony, everyone can agree that any new transmission line will improve system reliability. The question is by how much, to what extent, how often and how will that affect the underlying economics of the cost of providing electric service to ratepayers.

Rosen, Tr. at 5575. It is more than a matter of whether the line insures reliability but whether the utilities' argument that a higher standard of reliability is necessary:

So we can't just decide this case on the basis of what's needed to insure reliability. In fact, the loss of load study introduced into evidence in this case says that system reliability will be appropriately insured if we maintain an 18 percent reserve margin in Eastern Wisconsin, but we must look at the economics of going beyond the current level of reliability which appears to be adequate to a higher level of reliability.

Id. This is the cost benefit analysis that is to be included with an application for a high-voltage transmission line as required by Wisconsin statute, yet:

... no attempt has been made to quantify the benefits associated with continuing to have access to low cost power markets outside of Wisconsin which would be associated with the transmission line.

Smies, Direct Testimony, p. 4100; see also Wisc. Stat. § 196.491(3)(d)t.

The "market-based transactions" are competing for utilities' native service load for transmission access. In applicant WPS' territory, WUMS, utilities position for the "vigorous retail competition" of deregulation. Benforado, Tr. at 4773. Although the

electricity is being used, ultimately, by consumers, it isn't a public purpose because:

[T]he purpose of the transactions is for less for making the power available and more for changing the flow of money between the producers of the power and the purchasers of the power. And so that becomes a monetary issue rather than an electricity issue.

Schoengold, Tr. at 5373.

Because utilities are public service corporations, are regulated by the state and received benefits based upon that public service corporation, status, the state must assure that public service corporations remain focused on their obligation to serve their native load, and that their desire for increased market transactions remain secondary to that obligation. It is not the Commission's charge to facilitate economy transactions at the expense of a utility's native service territory customers.

## **2. Costs Defined**

The Arrowhead-Weston line will cost between \$149 and \$181 million dollars if built via the Owen route, and between \$175 and \$202 million dollars if built via the Tripoli and including the Tripoli-Rhineland loop. Valine, Tr. at 9586; Ex. 382, Total Project Costs (Millions of Dollars). Based upon the testimony of PSC staff, WPS submitted revised cost estimates on the final day of testimony in the hearing. Valine, Tr. at 9582, et seq. The cost estimates were revised upwards to include additional capacitors and transformers that had not been included. Id.; Ex. 287, Revised Version of Table 1-1 of the Final EIS; see also Ex. 172, FEIS, Table 1-1, p. 5. From the original estimates included in the application, the costs have risen slightly, but the Total Project Costs exhibit shows a low-high range that is significantly higher. Ex. 171, Appendix B; Exhibit 382, Total Project Costs.

There are other costs that have not been specifically addressed. One such expense is the potential for significant cost increases due to opposition to the line. Loock, Tr. at 4972. Included in all estimates is the upgrade of shared corridor lines to 161 kV using 795 or 954 KCM conductors which would provide increased capacity. These line upgrades to high capacity 161 kV are not specifically requested in the application, and were only addressed in testimony:

Xcel has stated that they would like their existing transmission facilities affected by double circuit construction with the Arrowhead to Weston line to be upgraded to 161 kV construction with 795 ACSR (26/7) conductor.

Valine, Dir., p. 4, Tr. at 6685; see also Jones, Tr. at 5901.

The costs of this project are necessarily unclear because it is not clear what exactly the project is. Ex. 171, Application, Table 1.1, et seq. from Vol. II, Appendix B; Ex. 276, Revised Cost Estimate Summary; Ex. 287, Revised Version o Table 1-1 of the Final EIS; Ex. 381 Arrowhead to Weston 345 kV Transmission Line: Crossing of Ice age Trail: Cost Comparison of Typical Construction vs. Super Tall Structures; Ex. 382, Total Project Costs (Millions of Dollars); Ex. 383, Arrowhead to Weston Transmission Project: Revised Cost Estimate Summary. Translating and comparing charts and tables and their revisions was confusing:

Q: ...and if we were to do all of those things correctly, why, is it true that we would get to a number that would reflect whatever the revised total including impact fee that we see in table 1.1 of the final EIS?

A: Yeah. If you did that correctly, then you would have the correct number.

Valine, Tr. at 6771.

The costs of undergrounding a transmission line are large, and cost allocation

is an issue in this proceeding:

Q: Who pays the construction costs of an underground facility?

A: In what situation?

Q: A situation such as this. We know what NSP's desire is but who typically pays for that?

A: Who the PSC says pays for it. Jones, p. 5921.

If a proceeding is contentious, there are increased costs. For example, if land must be condemned, there will be increased costs for the condemnation procedure and the associated challenges. Landgren, Tr. at 4584; see also Valine, p. 6782. The very nature of a protracted controversy will significantly increase costs. Ex. 262, Coal Creek: A Power Project with Continuing Controversies Over Costs, Siting, and Potential Health Hazards; Pilo, p. 6300-6310. Applicants have allowed for about five to ten percent wiggle room in cost estimates, but definitely more than five percent. Valine, Tr. at 6867. Some costs have not been added to the estimate, including a \$6 million dollar upgrade to the Rocky Run substation and the Forbes/Arrowhead upgrade to either 437 MVA or 345 kV, neither of which is addressed in the application.

It is not clear how applicants plan to recover the costs of construction of this line, other than cost recovery will not be accomplished in the traditional regulatory manner. In a Letter Agreement to Shippar of Minnesota Power, signed by both Schrickel of WPS and Shippar of MP, the parties agree that:

The Parties recognize that **the Project is being built to address the regional need for additional transmission facilities and that the traditional regulatory rate recovery methods do not adequately provide recovery of the costs from the entities that benefit from the Project.** Therefore, the Parties agree to develop and seek approval of a method by which the costs of the Project are allocated among users and beneficiaries of the Project. We agree that these

beneficiaries are, at a minimum, all eastern Wisconsin utilities, including WPS, Alliant (Wisconsin Power & Light), Wisconsin Electric Power Company and Madison Gas and Electric Company. We agree to develop and seek a cost recovery method where under MP includes the portions of the Project located in Minnesota (i.e. approximately 10% of the total Project costs) in its transmission network, and that revenue requirements related to the Minnesota portion of the Project will adequately reflect the benefits of the Project to Minnesota Power customers. We agree to jointly develop and seek regulatory approval of a method by which other parties including entities which will benefit indirectly through increased transfer capability and relief of congestion on other lines will pay an equitable portion of the Project revenue requirements. It is understood that the foregoing principles for cost recovery from beneficiaries will apply to the extent that revenues from scheduled transactions do not adequately recover the annual revenue requirements of the line.

Ex. 199, 11/12/99 Letter from WPS, and Sample Letter of Support for Project, p. 2; c.f. Miller, Tr. at 4703 (MG&E, Minnesota Power, Wisconsin Power and Light and WPPI benefactors of Arrowhead-Arpin in Advance Plan 8). Commission staff testified this matter would be under FERC jurisdiction, and “the costs here are for a transmission line which would show up in costs that the FERC would consider when establishing the various utility tariffs.” Pilo, Tr. at 3215. This is a FERC matter:

To the extent that it would be the cost recovery. I’m assuming this transmission line will be used by people that seek transmission service and it’s my understanding the Federal Energy Regulatory Commission has jurisdiction over the wholesale power market and the tariffs that are in place for the use of that transmission.

Pilo, Tr. at 6316. And when asked if it is then assumed that the purpose of the line is for the wholesale bulk power transmission, Pilo responded, “Yes.” Pilo, Tr. at 6316.

Where benefits of a project do not accrue to the public, “[t]he Commission has generally in the past assigned the costs of projects built to benefit specific entities to those entities, even when those projects were built by the regulated entity.”

Schoengold, Surrebuttal p. 2, Tr. at 5253. The Commission must issue a

determination that this project is not in the public interest and is not for the public benefit, and applicants must not be allowed to recover costs for this project in the rates.<sup>8</sup>

### **3. No Cost/Benefit Analysis has been completed**

As a part of a CPCN proceeding, the Commission must determine whether any incremental increase in reliability is worth the cost of the Arrowhead-Weston powerline. This analysis is typically completed through use of a cost/benefit analysis mandated by Wisconsin Statute. Wisc. Stat. § 196.491(3)(d)t. Yet despite the statutory mandate, there is no cost benefit analysis in the application. Ex. 171, Application. Despite the statutory mandate, none was completed for the project:

Q: So then, within your functions, you have not done a cost benefit analysis? A: Correct.

Q: You or your department?

A: Correct.

Smies, Tr. at 4232. Not one applicant witness could cite to or produce the cost benefit analysis mandated by Wisconsin statute. Without a cost benefit analysis, the Commission has no factual basis for a finding that the purported reliability benefits provided by the line are reasonable in relation to the line.

### **B. THE RELIABILITY BENEFITS OF WIRES AND WRAO'S PLAN 3J MAY NOT BE CONFERRED UPON ITS SUBPART, THE ARROWHEAD LINE, AS A STAND-ALONE PROJECT.**

There is no basis for a finding by the Commission that construction of the

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<sup>8</sup> The jurisdiction for rate recovery is unclear. Because this line is to be used for wholesale transmission, FERC would have jurisdiction over tariffs for use of that

Arrowhead-Weston line would confer reliability benefits as required by Wisconsin Statute. Engineering considerations must be considered as a part of the Commission's review, both regarding the electrical performance of the line and in cost calculations. Wisc. Stat. §196.491(3)(d)3. Any findings of the Commission regarding the Arrowhead line based only upon the WIREs and WRAO reports, which expressly stated that Plan 3 must be built in its entirety to achieve the reliability benefits, would be illegitimate. Applicants, however, rely solely on the WRAO and WIREs reports as their justification for the line, but nowhere addresses the fact that the Arrowhead-Weston project does not equal WRAO Plan 3j, and have done no independent analysis of the reliability benefits or electrical performance of the Arrowhead-Weston line as a plan separate from Plan 3j. Ex. 171, Application; Ex. 173, WIREs Phase I; Ex. 174, WIREs Phase II, Ex. 175, WRAO June 14, 1999, Report.

Q: And that is the entire universe of documents that you have provided in this proceeding regarding need?

A: I think that's somewhat circular in that all of the documents provided in this docket are the documents that we've provided in this docket on need.

A: But those specific things that you named, that's all there is?

Q: All of the exhibits, all of the testimony in this docket are all the documents that we've submitted in this docket for need.

Borgard, Tr. at 3383.<sup>9</sup>

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system. Pilo, Tr. at 6316.

<sup>4</sup> Applicants admit that participants in WRAO knew of WPS & MP's interest in the Arrowhead-Weston powerline project and that it was "one of the factors taken into account, certainly." See Borgard, p. 3415; Landgren Tr. at 4459, 4581. Knowledge that parties to WRAO had interest in this particular project may have had an impact on the outcome and ultimate WRAO preference of 3j. \ 6/99 MP letter, just before A-W application.



The one exception where the Applicants did not totally rely on WRAO and WIRES and where Applicant did independent work to justify this application and project was that part required for the "Rhinelander loop," a line from Tripoli to Rhinelander, which is part of the project purportedly to serve local load and which was not included in Plan 3j as analyzed. Plante, Tr. at 4077. There is no other instance where Applicant performed any independent review and study of the proposed project.

WIRES looked at many performance indices in its review:

WIRES Phase II narrowed the 12 representative reinforcements down to seven plans by determining relative performance differences between alternatives. The WIRES group then utilized the following performance evaluation techniques to study the remaining seven plans: detailed power flow simulation, generator response to transmission line switching operations, dynamic stability, voltage stability, impact on the MAPP transmission system, construction cost estimates, impact on system losses and evaluated cost proxy. These performance results were used by the WRAO in making their recommendation.

Borgard Direct Testimony, p. 17, Tr. at 3241; see also Plante, Direct Testimony, p. 23, Tr. at 3615; Landgren, Dir. p. 8, Tr. at 4427.

The Wisconsin Reliability Assessment Organization's report (WRAO) requires that a set of system improvements known as "3j" be built to achieve the reliability desired by the authors of that report:

In order to achieve the benefits which construction of plan 3j would provide, it must be constructed in its entirety. For all of the plans presented, several significant additions or upgrades to the underlying transmission system are required. Notably, the Chisago-Apple River 230 kV project presently under regulatory review in Wisconsin and Minnesota is considered a critical requirement for all of the plans (except plan 5a, Chisago-Weston 345 kV). The Chisago-Apple River project is an integral system reinforcement and is also critical for local load serving. If transmission plan 3j ultimately is not constructed in its entirety, the WRAO has identified transmission plan 5b

(Apple River-Weston 230 kV) as an alternative.<sup>10</sup>

Ex. 175, WRAO, p. 4. ATC's Landgren notes that the effects of the Chisago project on the reliability of Arrowhead has not been determined:

Again, we have not done a specific study to determine what impact that might have on the overall system that ATC has wither from a reliability perspective or an available transmission capability perspective.

Landgren, Tr. at 4495. Yet the WRAO clearly states that the Chisago project is one of the many accoutrements that must be completed to gain the reliability benefits of 3j and

the goals of WIREs and WRAO:

Again, because of the long standing transmission planning process in the state, as it was mentioned in my testimony and then the WRAO report, there are a significant number of smaller transmission system modifications and extensions that are necessary to be done along with this major line in order to accomplish the objectives that we laid out.

Landgren, Tr. at 4595; see also 4597.

In an effort to demonstrate that the Chisago line is not necessary to provide the reliability benefits of 3j, despite the findings in the summary of the WRAO report, Applicant produced an exhibit purporting to be a Chisago-Apple River Sensitivity study that shows the Transfer Capability, Damping, and Breaker Reclose Impact are not significantly different without the Chisago line. The Applicant's claim of reliability

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<sup>10</sup> Although the cities of Taylors Falls and St. Croix Falls have reached an agreement with NSP to construct the line, no agreement has been reached with the other local governments having jurisdiction, including Chisago County and the cities of Lindstrom, Center City, and Shafer. Chisago County currently has a powerline moratorium in place, has completed the Chisago Energy Management Plan (CEMP), and is drafting Essential Services ordinances. NSP has not made an application for this line to the County or any of the cities, and it is uncertain when and whether this line will be built. See also Jones, Tr. at \; Valine, Tr. at \.

benefits is invalid because the Sensitivity makes the assumption of **an upgrade of the Forbes-Arrowhead 230 kV line to a capacity of 437 MVA**. This upgrade has not been proposed as a part of the WIREs Report, the WRAO report, or the application, either in Wisconsin or in Minnesota. However, applicant testified that it was included because:

The old rating of that facility did show up in the transfer capability analysis. In discussions with Minnesota Power we felt that that upgrade was a reasonable task and **is required to meet the transfer capability levels that are found in that second column**.

Hamacher, Tr. at 4842 (emphasis added). Because the upgrade to 437 MVA it is not part of the planned project as proposed by applicants,<sup>11</sup> applicants may not validly assume the upgrade. And because the upgrade **“is required to meet the transfer capability levels that are found in that second column,”** the Arrowhead-Weston line will not meet those same transfer capability levels without that upgrade.

The specifics of the distinctions between Plan 3j Arrowhead - Weston 345 kV can be found in WRAO Appendix C1-3, which lists two alternate powerlines, substation upgrades, plus an additional 22 "associated projects and upgrades" which cost an estimated \$25 million dollars over and above the cost of the Arrowhead line and the substation upgrades. Id., App. C1-3; see also Plante, Tr. at 3712-3715. "Arrowhead-Weston is one of the components of plan 3j." Borgard, Tr. at 3454. These projects and costs do not include those of the delayed Chisago 230 kV

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<sup>11</sup> When asked if he was aware of any upgrades of the Forbes and Blackberry lines going to Arrowhead, Borgard testified that "I myself am not aware of upgrades required on 230 or any other lines coming into the Arrowhead substation." Borgard, Tr. at 3734. See discussion supra, p. \, and fn. \, Hamacher testimony regarding upgrade of this line to 437 MVA.

powerline.<sup>1</sup> From this chart, it is apparent that plan "3j" is not the Arrowhead line, it is the Arrowhead line with many additional improvements that are not planned. Id., App. C1-3.

Q: And so the question is is there a difference between the Arrowhead-Weston power line with a bunch of smaller components, is there a difference?

A: Yes, the second has more things than the first.

Borgard, p. 3454.

However:

I don't believe that the WRAO did any analysis of just building a line from Arrowhead to Weston in the absence of any other reinforcement that may be part of plan 3j.

Borgard, Tr. at 3371.

Are the differences between "plan 3j" and "Arrowhead-Weston" significant?

According to PSC-WI's staff engineer, Steve Leovy, they are:

Yes. The upgrades do make a difference for the performance of those options. The WIRE study did find that those upgrades would be necessary in order to achieve the target transfer capability of that study.

Leovy, Tr. at 5952. When asked to quantify the percentage of the benefits attributable to the Arrowhead-Weston line distinct from Plan 3j, the Applicant stated:

I'm not sure if I or anyone else could give you an exact percentage but it's clearly the majority, a high percentage above 50 percent but beyond that, I don't think I could be any more specific.

Borgard, Tr. at 3584; see also Plante, p. 3665, 3712. Borgard admitted that there were no studies to support this statement. Id., Tr. at 3585.

Leovy testified that exclusion of these associated projects in Plan 3j was not a great concern because the Commission had the authority to order the projects

completed to maximize the potential of the project. Leovy, Tr. at 5953. There is no indication from the application or proceedings, however, that any determination has been made to determine which projects would maximize the potential of the project or that the Commission is considering such unspecified changes.

**1. The Arrowhead-Weston line will not provide the claimed reliability benefits without upgrades to Forbes-Arrowhead that have not been incorporated into the plan.**

The Applicants have not included projects necessary for the Arrowhead-Weston project to provide the reliability benefits claimed. One such improvement is the conductor upgrade of the 230 kV line from Forbes to Arrowhead to a capacity of 437 MVA or a voltage upgrade to a 345 kV line, either of which would provide the increased capacity into the Arrowhead substation to power the line. More importantly, without an upgrade of the Forbes to Arrowhead line, the project does not perform as planned.

The importance of the capacity increase through a conductor upgrade raising the line to 437 MVA is shown in the Chisago-Apple River Sensitivity. Ex. 208, Load Flow Study Results – Chisago-Apple River Sensitivity. The WRAO report stresses that the Chisago line must be built to achieve the desired reliability benefits. Ex. 175, WRAO, p. 4. The PSC staff engineer agrees that “[t]he Chisago-Apple River line is one line that would have some impact on flows.” Leovy, Tr. at 6181. To show that the Arrowhead project is not dependant on completion of the Chisago line, modeling was completed by Hamacher that included transfer capability, dynamic stability, and source sink sensitivity analyses. The results were put into a table which purport to show that the line will perform adequately without the Chisago-Apple River line **IF** specified assumptions were made. Hamacher, Tr. at 4840-41. Using the WIREs

study database and base case, the Chisago-Apple River line was removed and a 345 kV to 161 kV step down transformer was added at the Stone Lake Substation. Id., Tr. at 4838-9. Hamacher claims the results “were very similar to the plan 3j that was modeled in the WIRE study.” Id., Tr. at 4840. However, this modeling that shows that for the Arrowhead-Weston line to perform adequately, the project must also include the upgrade, likely reconductoring, of the 230 kV line from Forbes to Arrowhead to increase the capacity to 437 MVA. Hamacher<sup>12</sup> testified that:

The old rating of that facility did show up on the transfer capability analysis. **In discussions with Minnesota Power we felt that that upgrade was a reasonable task and is required to meet the transfer capability levels that are found in that second column.**

Hamacher, Tr. at 4842.<sup>13</sup> Without the upgrade, the Arrowhead line will not meet the transfer capability levels.

Hamacher’s statement that an upgrade of the Forbes-Arrowhead line is necessary correlates with the analysis of the PSC staff engineer,<sup>14</sup> who received a power flow printout after a specific request of an applicant:

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<sup>12</sup> Hamacher has a B.S. in Electrical Engineering and is WPS’ Regional Electric Engineer, responsible for technical support for those that design, operate, and maintain the electric power distribution system. Hamacher, Dir. at 1, Tr. at 4817.

<sup>13</sup> This document had not been provided to Intervenor, despite W.O.L.F.’s specific requests regarding potential upgrades, on the record at the hearing, WPS’ counsel stated that “it also has been in the document room which has been available to all parties since May. It was in the materials that had been made available to all of the parties.” Tr. at 4844. However, all documents in the document room have a number stamped in the lower left corner, and this document does not. Attorney for W.O.L.F. reviewed all documents in the Engineering file twice, copied most, and this document was not among them.

<sup>14</sup> Steven Leovy has a MS in Electrical Engineering with an emphasis on electric power systems and is a staff engineer in the PSC’s Electric Division. His primary responsibilities involve analysis of the electric transmission in Wisconsin. Leovy, Dir. at 1, Tr. at 5956.

PSCW staff inquired of MP in spring 1999 about improvements to existing Arrowhead substation connections that might be **required** by construction of the Arrowhead-Weston line.

Leovy, Tr. at 6173 (emphasis added). “MP responded with on one page fax on 4/6/99 that provides some load flow modeling results.” Id.; Ex. 200, Fax from Dan Carlson of MP to Dave Barger of Commission Staff: Load Flow Study Results, p. 2. Based upon those load flow modeling results, the staff engineer “performed AC contingency analysis to assess the importance of improving connections between Forbes and Arrowhead if an Arrowhead-Weston line is built.” Id; see also Leovy, Tr. at 6171-6180. Engineer Leovy found through his modeling that:

Nonetheless, this initial look does indicate that, at 200W/100S transfer levels, with the DC line out of service:

The existing rating of Arrowhead-Forbes 230 is low enough that it is almost exceeded with all lines (other than Square Butte DC) in service;

This rating is exceeded if any of a large number of additional line outages occurs;

Outage of Blackberry-98L Tap 230 (with DC line out) leads to loading of Arrowhead-Forbes 230 well in excess of 437 MVA – the proposed rating after work to increase rating;

Outage of Arrowhead-Forbes 230 probably overloads Blackberry-98L Tap 230.

A new 345 kV connection eliminates most or all of these overloads;

It is appropriate to consider contingencies that include line outage in addition to outage of the DC line, the analysis should consider critical contingencies. For the 2000W/1000S transfer conditions, outage of Blackberry-98L Tap 230 is likely to be a critical contingency, and in any case will almost certainly be a more significant contingency than the Arrowhead-98L Tap outage modeled in the MP fax.

Ex. 200, Need for Arrowhead-Forbes 345 kV Connection in Conjunction with

Arrowhead-Weston 345 kV line --4/9/99, p. 2.

The MP load flow modeling results and PSC's "Need for Arrowhead-Forbes 345 kV Connection" were provided to Intervenor W.O.L.F. in response to a data request:

For the Arrowhead to Weston line to meet the maximum transfer capacity are there any other upgrades **required** to any of the transmission lines into or out of the Arrowhead substation either directly or indirectly.

Leovy, Tr. at 6172.

Hamacher stated in his testimony that the upgrade to 437 MVA "**is required to meet the transfer capability levels.**" Hamacher, Tr. at 4842. When asked what upgrades "that might be **required** by construction of the Arrowhead-Weston line. Leovy, Tr. at 6173. Leovy produced these documents when asked whether "to meet the maximum transfer capacity are there any other upgrades **required.**" Leovy, Tr. at 6172. The operative word is "**required.**" According to both WPS' engineer Hamacher and PSC's engineer Leovy, the Forbes-Arrowhead line must be upgraded to provide the touted reliability benefits, both generally and without the Chisago line, and to meet the maximum transfer capacity.

Based upon the testimony of WPS' Hammacher and PSC staff Leovy, the Arrowhead-Weston line will not function electrically as planned without upgrades and will not provide the reliability benefits attributed to Plan 3j as set forth in WIREs and WRAO.

## **2. Interconnection of electrical facilities and the impacts of interconnection have not been adequately considered.**

The applicants have not adequately addressed the impact of their proposed



powerline on the systems of other utilities and on the interconnected grid as a whole.

The importance of interconnectedness has been recognized by the state as a factor in increased reliability through wider accessibility of generation and decreased electricity prices due to availability of lower cost power. Ex. 222, Report to the Wisconsin Legislature on the Regional Electric Transmission System, p. vi. Under the state's transmission planning guides:

Adequate transmission planning requires joint utility study of areas where transmission facilities of different companies affect each other, such as in utility boundary areas. Joint planning means investigation of an area on a single-system basis with the objective of identifying problems and solutions, irrespective of transmission system facilities' ownership.

Criteria for Transmission Network Planning and Design, AP8, p. D23b-6, No. 13 (citing AP-4 Order Point 46). The Advance Plan recognizes that many utilities plan together, and noted that, "This is the only way that transmission planning is done in the state of Wisconsin." Id. The reason is simple:

If Wisconsin is not well connected to the regional transmission grid, it will not be able to get the full benefits out of participation in these organizations. Additionally, without transmission sufficient to promote vigorous competition, the market incentives to produce low cost local generation will be lost. A strong interconnection to the regional transmission network is beneficial for Wisconsin's overall economic health as well as for its ability to provide a reliable power supply to its residents, businesses, and industries.

Landgren, Tr. at 4434.

There were many opportunities for shared corridor presented in the application, specifically those shared with and identified by NSP as Power Up segments 125, 130, 139, 142, 144, 153, 207, 211, 213, 238, 243, 304, 310, 312, 320, 330, 332, 340, 341, 343, 346, 352, 357.

Ex. 171, Application, Fig A32-2, NSP letter. This letter stated that:

NSP believes it is a reasonable request for the project to assess and include routes that have a benefit for future interconnections with our transmission line grid in Northwestern Wisconsin. Up to this point, no joint studies have been conducted to determine what locations would be the best sites to ensure the new 345 kV transmission line is located a reasonable distance to provide an interconnection to benefit the transmission grid. There are several substations that have good potential (Stone Lake, Trails End, Osprey and Prentice), but at this point, NSP does not have enough information on the performance of the various interconnections and the costs and impacts of additional upgrades that would likely be required.

Ex. 171, Application, Figure A32-1-4, Letter to Dave Valine, WPS, cc: Don Jones, NSP, August 9, 1999. NSP's letter admits that the parties have not done adequate transmission planning as defined by the state, confirmed by its witness:

Q: Have you or anyone at NSP or Xcel conducted a load flow analyses to determine the impact of the line upgrades that would be associated with the Arrowhead-Weston line?

A: Not outside of the context of the Wires study.

Jones, Tr. at 5893. Despite this lack of planning, NSP is demanding an upgrade of all of its lines in conjunction with corridor sharing with the Arrowhead powerline:

Finally, NSPW also believes that the NSPW facilities reconstructed in this fashion should be installed at a voltage capacity high enough to obviate upgrades for the next 10-15 years.

Jones, Dir., p. 3, Tr. at 5873. When asked about the purpose of upgrading to a higher voltage or capacity, Jones responded:

I think the intent of that language in the testimony there is only to indicate an initial position of NSP Wisconsin and the construction should be in such a way to accommodate future needs.

Jones, Tr. at 5887. The upgrade to 161 kV matches NSP's intention to complete the Chisago line as a 161 kV line and NSP admits a desire to upgrade its conductors for increased capacity in association with the Arrowhead project:

Q: But logically you wouldn't be upgrading a 161 to 161, correct?

A: That's not necessarily true. Because the existing capacity of the existing 161 may not be adequate for the future and you would want to upgrade this capacity.

Q: Say in terms of conductors?

A: Yes.

Jones, Tr. at 5901. No application has been made for this upgrade. Id., Ex. 171, Application, Appendix B (no mention in application, but 161 kV upgrade included in cost charts). Jones was reluctant to address any specific interconnection, particularly in relation to connection of the Arrowhead project with the Chisago 161 kV project:

Q: And will this line with the 161 upgrades with the Arrowhead project be connected to the Apple River substation?

A: Again, I haven't studied none of that and I don't know the final configuration of the applicant's facilities until that has been concluded and I expect that I will work with the applicants and look at various scenarios that might look prudent to do.

Q: Well, hypothetically if it comes quite close to the apple River substation, would the lines be connected?

A: Hypothetically if the line came close to anywhere, it might be connected.

Jones, Tr. at 5913.

Q: Hypothetically, if there is a 161 upgrade to the existing system that you have in association with the Arrowhead project and if there is a connection between the Arrowhead project and the NSP 161 system and if there is the Chisago-Apple River 161 kV line going to Apple River, then if those things happen, then there would be an electrical connection between Chisago and the Arrowhead-Weston project, correct?

A: If you connected all the systems together, they would be connected.

Jones, Tr. at 5918. The potential for the utility desired interconnectedness of the two projects was also admitted by WPS:

Q: So to your knowledge, will the Chisago line, will an additional segment be connected to this line?

A: No.

Q: Could it be connected to this line?

A: It's possible if you connected them, they would be connected.

Valine, Tr. at 6747.

The applicants have not submitted for the record any analysis of the potential for interconnection between the Chisago and Arrowhead projects and whether any reliability benefits could result and were reluctant to admit to any interconnection, despite significant opportunities for shared corridor and NSP's demand for an associated upgrade to its lines. This necessary analysis of interconnection is regarded as "adequate transmission planning" by the state, and the project application has not met this standard.

**3. Necessary electrical performance studies and system analyses have not been produced.**

The applicants have not produced a cost benefit analysis, nor have they produced provided any demand projections or load flows and dynamic stability studies as required by the state. The applicants have also not produced the power flow modeling for impact analysis, power transfer distribution, outage transfer distribution or made any determination as to whether there is sufficient available transmission capability on the system. These studies must be produced and analyzed by the Commission before any decision may be responsibly made. If the Commission proceeds without these studies, it is making a decision without any factual basis.

The state requires a cost benefit analysis demonstrating that the reliability

benefits provided by the proposed project are reasonable in relation to the cost of the project. Wisc. Stat. §196.491(3)(d)3t.<sup>15</sup> This has not been provided as a part of this application. Plante, Tr. at 3722; Schoengold, Surrebuttal, p. 5, Tr. at 5256. A DSM assessment to determine energy efficiency opportunities has not been completed. Schoengold, Tr. at 5375. The Applicants have also not provided any demand projections or load flows and dynamic stability studies, on Arrowhead as a stand-alone project and not 3j, to the Commission as a part of their application. Wisc. Code. §111.43(1)(d)4; Plante, Tr. at 3722, 3729. Such studies, and more, are required by MAPP's Design Review Subcommittee,<sup>16</sup> which as a part of the review process requires power flow modeling for impact analysis on MAPP's regional constrained paths or other related paths; power transfer distribution factor to determine the impact of the Arrowhead-Weston line on constrained paths; outage transfer distribution factor to address the megawatt flow on the limiting facility for outages of critical facilities; and a determination as to whether there's sufficient available transmission capability on a regional constrained party sufficient to accommodate the Arrowhead- Weston line as distinct from 3j, none of which have been completed, submitted with the application, and/or included on the record. Plante, Tr. 3729-32.

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<sup>15</sup> See also AP8, Criteria for Transmission Network Planning and Design, Nos. 2, 3, 4, 9, 12, 15, 16, 17.

<sup>16</sup> Applicants go so far as to assert that MAPP has no jurisdiction over the line:

I don't believe that the MAPP review and design committee has any power to preclude somebody from building a transmission line that's been authorized by the appropriate regulatory agencies.

Borgard, Tr. at 3378.

No reliability studies have been completed by any party on the Arrowhead line as a stand-alone project. Borgard, Tr. at 3371, 3372; Plante, Tr. at 3729-32; Leovy, Tr. at 6184.

Q: ...We've been talking about 3j quite a bit, and that the WIRES review is based on the entire 3j. And it's correct that there has been then no independent analysis of just the Arrowhead-Weston, correct?

A: None other than what may be contained in the application, no.

Borgard, Tr. at 3373.

Q: Has WPS conducted any more recent studies to support its claim of need?

A: I don't think we've conducted any other studies other than what's in the application or on the record here.

Borgard, Tr. at 3372; see also Plante, Tr. at 3709.

Not only have the applicants failed to produce the requisite studies, but they have not been completed by the PSC:

Q: It would be correct that the staff has not reviewed specific –power flows and dynamic stability studies specific to this line? ...

A: I guess that's correct.

Q: Have load flow or dynamic stability studies been provided by the applicants to staff? ... Is it correct that there were no load flows or dynamic stability studies with that application, accompanying the application?

A: I don't know that we've seen that information including only those items in the application and not including the other reinforcements that were deemed or found to be necessary.

Leovy, Tr. at 6184.

These necessary studies have not been completed for the Arrowhead-Weston line as distinct from 3j, and Applicants are relying solely on the WIRES and WRAO studies. Id. Yet despite this dearth of stand-alone studies on the Arrowhead- Weston

line and any independent substantiation of their position, applicants claim that:

**To suggest that our reliability situation will improve without more wire in the air is wishful thinking.**

Borgard, Surrebuttal, p. 3, Tr. at 3264; Tr. at 3569.

The reason these studies have not been completed is revealed in the testimony of the applicants, who readily admit that the reliability benefits they claim the Arrowhead-Weston line will provide are illusory. Not one applicant witness testified that the reliability benefits of the arrowhead line equaled those of 3j in the WRAO report. Without the appropriate studies to support the Applicants' claims of need and reliability, there is no justification for a Commission finding that the line is needed or provides reliability.

**C. APPLICANTS' CLAIM THAT THE PHASE ANGLE PROBLEM JUSTIFIES POWERLINE IS RUSE WHERE OTHER LESS DRASTIC SOLUTIONS HAVE NOT BEEN IMPLEMENTED OR CONSIDERED.**

There is no basis for a finding by the Commission that the phase angle problem justifies construction of the Arrowhead powerline. Applicants have repeatedly testified that they have not considered use of simple and relatively inexpensive fixes such as single pole reclosing, phase shifting transformers or unified power flow controllers, which, if utilized, would significantly reduce or eliminate the phase angle problem.

Phase angle is a somewhat complicated phenomenon of electrical transmission. See Ex. 171, Application, p. 20; Ex. 172, FEIS, p. 42-3; Ex. 175, WRAO, 4; Ex.222, p. 16-17. In its report to the legislature, the PSC explained:

Power system generators are large rotating machines. All generators in the Eastern Interconnection rotate at the same rate, their synchronism maintained

by the exchange of electrical energy through the connecting transmission network. Although they rotate at the same rate, some generators are slightly ahead of others in their rotational position. This results in the AC voltage at some generators being slightly out of phase with that at other generators – referred to as a difference in phase angle between generators... The degree to which they are out of phase is the phase-angle difference...

Even if the two areas do not lose synchronism, a line outage can cause the two areas to “swing” relative to each other, increasing the phase angle between them...Consequently, system operators must restrict power transfers as required to limit the phase-angle difference which could develop across a line that is out of service.

Ex. 222, Report to Legislature, p. 16-17.

In the FEIS, PSC staff narrowed the problem to three critical characteristics to consider:

- 1) the phase angle across a line will tend to increase during high transfers and, particularly, when the line trips out of service;
- 2) reclosing a line (returning the line to service) when a large phase angle is present across the line can pose a shock to the system that can disturb or damage generators or other equipment; and
- 3) in general, the only practical way to reduce such large phase angles prior to reclosing the line is to redispatch generation (adjust the generation levels of power plants in the region).

Ex. 172, FEIS, p. 42 (emphasis added); see also Leovy, Tr. at 6186.

Single pole reclosing, use of a phase shifting transformer on the east end of the line, switched series reactor and unified power flow controller are all options to control phase angle. Ex. 172, FEIS, p. 42-43; Ex. 222, Report to the Wisconsin Legislature on the Regional Electric Transmission System, p. 19, 33-34.

Applicants state that these technologies were rejected by the WIREs group, but although Plante testified that these alternatives were rejected, studies were not done and that these alternatives were rejected based on “the collective experience of all of the transmission experts that were involved in the WIREs study group.” Plante, Tr. at



4086. When asked to point out specifically in the WIRES or WRAO reports where these solutions were rejected, Plante's response was:

I'm not able to put my finger on any statement that directly states that the group dismissed those as potential reinforcement alternatives.

Plante, Tr. at 4091. They were not specifically rejected by either WIRES or WRAO in either document. And when asked to point out any discussion of these solutions to the phase angle problem in either the WRAO or WIRES report, he could not find any discussion of phase angle alternative solutions in either report. Id. There is no record whatsoever of consideration of these mitigation options in the WIRES or WRAO report.

Applicants, ATC, and the PSC have not devoted sufficient analysis to alternative methods of addressing the phase angle problem. . Ex. 172, FEIS, p. 42-43; Ex. 222, Report to the Wisconsin Legislature on the Regional Electric Transmission System, p. 19, 33-34, Landgren, Tr. at 4489-90. For example, mitigation through use of single pole reclosing has not been evaluated "to any appreciable extent." Leovy, Tr. at 6186.

Use of a phase shifting transformer at the east end of the line was only discussed:

Again, there's been some discussion within staff and together with utilities and the WIRE study participants and also the consultant that was retained in the summer of 1998 and I'm not aware of any particular recommendations that have come out of that.

Leovy, Id. Use of a uniform power flow controller has not "been considered in any detail. Leovy, Tr. at 6186-7. Likewise, use of a switched series reactor was addressed in the EIS but no action has been taken. In the EIS, the Commission's staff engineer found that:

The simplest solution would be to install a 345 kV switched series reactor at

the Arpin substation. This device would normally be disconnected from the transmission system, but upon a trip of the Eau Claire-Arpin line, it would be inserted in series with the transmission circuit before reclosing the line. A reactor acts to resist the flow of alternating-current electricity, and can reduce the magnitude of the power surge that accompanies line reclose. Once the line has been reclosed, the reactor could be bypassed and then removed from the circuit.

Id., p. 176, n. 119.

Although there are many alternative methods of phase angle correction and mitigation, some of which are relatively inexpensive and all of which are inexpensive in comparison to the Arrowhead line, these methods have not been adequately investigated and there are no plans to use any of these methods to address the problem. That reluctance to use reasonable methods to control a problem complained of is indicative of use of the phase angle problem in an attempt to justify the line and the utilities desire to build the line for reasons other than correction of “the problem.”

**D. SYSTEM OUTAGES ARE SYMPTOMATIC OF UTILITIES' ABUSE OF THE TRANSMISSION SYSTEM IN SEARCH OF INCREASED MARKET TRANSACTIONS AND ARE NOT PROOF OF A RELIABILITY PROBLEM OR NEED FOR THE LINE.**

There is no basis for a Commission finding that the proposed Arrowhead powerline is needed due to outages because outages are not a symptom of need. See Wisc. Stat. §196.491(3)(d)2. The applicants claim that the transmission line disturbances of June 10-11, 1997, June 25, 1998, and June 10, 1999, demonstrate the potential for blackouts and lack of system stability. Ex. 171, Application, §3.2 Recent Reliability Problems in Wisconsin, p. 8-15, Terhune Dir. p. 6, Tr. at 4445; Benforado, Dir. at 2, Tr. at 4744; Miller, 4687-90. However, the examples do not

support this justification and instead show a utility operating practice of overloading the lines to increase market transactions. Id., p. 10. For example:

On several occasions in June of 1999, transmission system operators experienced heavy flows on the 345 kV line between Minnesota and Wisconsin in excess of the line's capability. Operators could not restore the line's flow to safe level within a reasonable amount of time and exceeded operating reliability criteria established by NERC.

Id. Operating the lines at capacity equal to or greater than design standards exacerbates the impact of even expected contingencies:

Operating for long periods at or near operating security limits allows conditions or events which are not yet apparent to the operator to compound the electrical effect of the contingencies the operator is anticipating, without the operator's knowledge, and without any additional margin of safety for those potential undetected conditions. Moreover, operating at security limits restricts both response time and flexibility when events (lightning, tornadoes, ice storms, accidents, equipment failure) suddenly remove key facilities from the system. Put succinctly, operating at or near security limits on a regular basis significantly increases the stress on the power system; increases the probability of undesirable conditions worse than anticipated single contingency failures such as instability, voltage collapse, or cascade tripping of transmission lines; and consequently increases the probability of widespread service interruption affecting Wisconsin customers.

Terhune, Dir. p. 9, Tr. at 4448; Landgren Dir. p. 3, Tr. at 4422. Operating the system at its limits puts the system at greater risk. Terhune, Tr. at 4545.

This utility practice of overloading the lines and putting the grid at security risk is in direct contravention of the intent of FERC Order 888, under which a utility is not required to provide access if the transaction would undermine the security or reliability of the system. FERC Order 888. Applicants agree that this is the policy set out by FERC. Plante, Tr. at 3691. Plante also testifies that utilities have "the right to study the impact of transmission service request" and:

Not only do they have the right, I believe they have the obligation.

Plante, Tr. at 3691. Unfortunately, there is no specific active requirement of protection of the grid, and utilities are stretching the technical boundaries and laws of physics. Ex. 246, NERC Reliability Assessment, 2000-2008. When security limits are exceeded, the choice presented is “TLRs or interruptions of those schedules or live with lower reliability.” Landgren, Tr. at 4529.

The utilities' capricious operating practices are apparent in the reports of the individual outages, all of which cite overloaded lines as a precipitating factor. See Ex. 194, Northern MAPP/Northwestern Ontario Disturbance -- June 25, 1998 -- Final Report; Ex. 195, Nebraska Public Power District - Report on June 10-11, 1997 Disturbances; Ex. 196, Power Decisions Consulting: June 10, 1999, Investigation Eau Claire-Arpin Line Loading; Ex. 260, Bulk Power Markets: Midwest Region, 11/1/2000; Ex. 246, NERC 2000-2009 The Reliability of Bulk Electric Systems in North America; see also Terhune, 4482, 4485 (heaving loading was condition precedent); Miller, Tr. at 4688-90.

To help identify which transactions were causing the overloads, NERC initiated transaction “tagging” in 1997, but despite that initiative, the tagging is not always used. Ex. 245, NERC Reliability Assessment 1999-2008, p. 54; 56; see Ex. 196, Power Decisions Consulting: June 10, 1999, Investigation Eau Claire-Arpin Line, p. 7-8.

One of the purposes of a transaction tag is to identify the source from the sink to make it possible to use transmission tools to identify what proportion of that transaction flows through each relevant line.

Terhune, Tr. at 4561. Although E-tags can also be used to track the “offending” transactions, many transactions are not being recorded, making it impossible for

operators to know the status of available capacity. This practice was a contributing factor in one of the outages cited by Applicants. See Ex. 196, Power Decisions Consulting: June 10, 1999 Investigation Eau Claire-Arpin Line Loading, p. 7-8.

Applicants admit that the practice of overloading the lines is a benefit to utilities because the excess electricity on the lines is dispatchable -- it can be sold:

Q: And would you agree that when lines are overloaded, during that time period that they are overloaded, that is dispatchable...Let's just say that the limits of the line are 800. It's overloaded now to 1,000. During that 30 minutes a utility may sell that additional 200 before it has to be reduced, correct? That is dispatchable, correct?

A: If the limit on a line is 800 megawatts, and there is 1,000 megawatts flowing over that line, presumably somebody is dispatching generation that is flowing over that line in excess of its 800 megawatt limit.

If that generation is going -- is part of a sale to somebody else, then, yes, somebody is selling that extra 200 megawatts...

Borgard, Tr. at 3403-4.

For example, the report of the Nebraska Public Power District (hereinafter NPPD) regarding the June 10-11, 1977, disturbance states:

Due to the light load condition and low cost MAPP generation, there were high simultaneous exports into the MAIN and SPP regions...

Also at this point, the loadflow indicated numerous overloads on 345 kV and 161 kV ties between MAPP and MAIN/SPP...

And when NPPD modeled the disturbance in a reconstruction, including the numerous overloads, "the results of that simulation were quite alarming."

Ex. 195, p. 2 (emphasis added); see also Borgard, Tr. at 3399-3401; see also Terhune, Dir. p. 6-7, Tr. at 4445-6, 4478-9.

This event should not be filed away as just another close call. We need to recognize just how close we were to collapsing portions of the Eastern Interconnection and adjust operating guides and reporting practices to avoid reoccurrence. There are real limits to the transfer capability out of the MAPP region and those limits are interdependent. This event is an alarming

representation of how the MAPP regional interconnected system is being operated at and even beyond it's (sic) capabilities.

Id., p. 1-2 (emphasis added). This report expresses concern that the MAPP system is being run beyond its capabilities by the utilities as a matter of course, and that this practice puts the entire grid at risk.

The incident of June 25, 1998, was similar in causation. The primary recommendation of that report was that "[t]he system must be operated within approved Operating guide limits." Ex. 194, Northern MAPP/Northwestern Ontario Disturbance – June 25, 1998 – Final Report, p. iii. The report begins, "[i]n the early morning of June 25th the MAPP system was operating with heavy transfers east to MAIN and south to SPP." Id., p. 1. After the initial Prairie Island-Byron trip:

The TCEX flow was approximately 200 mW above the adjusted stability limit...This can be clearly seen in Figure #17, which shows the TCEX flows during the day on June 25th...The NSP Operator focus was on reducing the phase angle to allow reclosing of the Prairie Island-Byron 345 kV line, which had been successfully energized from both ends, and not on reducing flows to reduce TECX to the prior outage limit.

Id., p. 10-11, Figure 17.

...If the TCEX flow would have been reduced to the Operating Guide limit of 700 mW prior to the King-Eau Claire 345 kV line trip, the disturbance may have been prevented.

Id., p. 12. "The Northern MAPP part still had too much generation. Terhune, Dir. p.7, Tr. at 4446. NSP operators did not reduce line loading sufficient to prevent the second contingency, and the report alludes to delay and resistance to curtailment:

The MAPP SCP has also indicated that MAPP Members routinely call and question the request schedule curtailments, which may further delay implementation of the schedule curtailments.

Id., p. 13.

The system security problem is that the lines are overloaded and operating beyond security limits:

The MAPP Security Center Operator (SCO) must be aware of the presence of an Operating Security Limit Violation where the system conditions are outside of approved MAPP Operating guides, and ensure actions are taken to return the system conditions within Operating Guide limits in the allowable time limits.

Id., p. 26.

It is apparent from the report of the June 25, 1998, disturbance that established operating guides are not being followed by system operators. There have been delays in implementing curtailment orders and frequent challenges to those orders. When specific incidents are reviewed, the recap of events is "alarming." And the trend of capricious operation of the system for economic benefit is apparent:

An unexpected threat to reliability materialized in late July 1999 when system frequency on the Eastern Interconnection dipped to one of its lowest levels in history (59.93 Hertz). This occurrence was later shown to be due to significant under-generation by at least two control areas in the central United States during times of very high energy prices. Control areas with a significant market exposure will effectively take energy from the rest of the Interconnection when prices are high and replace it when prices are lower if they do not purchase the energy to cover their obligation. NERC operating policies require that systems short of power shed load to protect the integrity of the grid in cases where no purchase power is available, **but the experience of July 1999 shows that abuses driven by spikes in energy prices can alter behavior, leading to a significant threat to reliability.**

Ex. 246, NERC 2000 Reliability Report (emphasis added).

Transmission service is being sold and transactions are being scheduled without regard to the impacts of those schedules on the entire network. As a result, the capabilities of the network are being oversubscribed. Instead of managing the transmission system before the fact through wide-area calculation and coordination of ATCs, the security coordinators end up managing the resultant problems and not the root cause.

Ex. 245, NERC 1999 Reliability Report.

A load-serving entity purchasing transmission service from an adjoining transmission provider to supply native load does not have to post a transmission reservation on his own system, thereby creating another form of partial path reservation.

Ex.245, NERC Reliability Report, 1999 p. 53.

There is no basis for a finding by the Commission that the addition of another high-voltage powerline will increase reliability or do anything but increase the applicants' market transactions. These are examples of industry policy in wholesale wheeling, where moving power is the highest priority and bulk power sales and transfers are completed by putting the security of the system at risk. The power system is overloaded by the operators and is at risk of collapse. The utilities are operating the system beyond its limits, endangering the grid, reliability, and electrical service across wide geographic areas, and these practices have extreme potential for human impact by endangering the public's ready access to necessary electricity.

**1. Abuse of the transmission system is an industry wide problem that threatens reliability of the transmission grid.**

There is no basis for a finding by the Commission that the Arrowhead project is needed for reliability because the risk of grid collapse is an industry created "crisis." Prompted by many complaints about the management of the bulk power transmission system, FERC commissioned a study of the Midwest's Bulk Power Markets. Ex. 260, Investigation of Bulk Power Markets, Midwest Region, November 1, 2000, Federal Energy Regulatory Commission Study Team. This study found regulation inadequate to prevent abuses of the transmission grid, specifically that:

NERC's guidelines and procedures for maintaining system reliability in control areas are voluntary. Thus, the NERC guidelines and procedures are not



enforced by remedies such as penalties or refunds. Although the Commission has required utilities to place certain of the NERC standards and procedures into their respective OATTs, the Commission has generally deferred to NERC on transmission reliability questions, including the propriety of TLRs called by transmission providers and Security Coordinators. As a result, in the rare instance that regulatory action has been taken, it has been reactive rather than pro-active, with only prospective impact in localized areas.<sup>17</sup>

A number of institutional problems related to bulk power transfers were addressed by the report, including lack of posted information on TLRs<sup>18</sup> and schedule curtailments, uncertainty in ATC and CBM calculations, lack of uniformity in processing transmission requests and schedules, inadequate information for real-time monitoring. *Id.*, p. 2-34 to 2-40; Leovy, Tr. at 6200; see also Ex. 245, NERC Reliability Assessment, 1999-2008, p. 54.

Applicants bemoan the constraints of the transmission system, but even if the line were built, there is nothing to suggest that market forces would not again clog the new line with transactions:

Yes, the two interfaces could remain constrained, due to other firm transactions not serving Wisconsin customers, if the system operators allow such a situation to arise, but that would be a threat to reliability caused by inappropriate system operations rather than by a lack of transmission interties.

If transmission is set aside for capacity reserve purposes, there is no justification to allow other economic transactions not benefiting Wisconsin customers to threaten the use of those reserves by loading the line to dangerous levels and then being hesitant to interrupt these other firm transactions, if necessary. As long as the Commission allows utilities to maintain some of their reserves in the form of imports of firm power contracts,

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<sup>17</sup> See also "Transmission Markets, Stretching the Rules for Fun and Profit," Naarasimha Rao and Richard D. Tabors, TCA Working Paper No. 327-0400, April 2000 (cited fn. 28, Investigation of Bulk Power Markets: Midwest Region).

<sup>18</sup> Transmission Loading Relief (TLR) is an escalating series of curtailment procedure established by NERC to decrease power on a line or flowgate that is overloaded or in violation of established operating limits.

that capability must not be threatened by the risky operational management of the line. The whole point of "reserves" is to actually reserve capacity so that it is available if needed in an emergency

Rosen, Dir. P. 44-45, Tr. at 5451-52

But while they may bemoan the "constraints" of the Eau Claire-Arpin line, the Transmission Loading Relief (TLR) charts which set out the number of potential or actual violations on constrained flowgates present a different picture. Several facts in this report establish the background for the charts: The Growth in Peak Load in MAPP has actual been a nearly 3,000 MW, or 6.8% decrease. Table 2-5. In 1999 and 2000, there has been a 366 MW increase in generation capacity. Table 2-6.<sup>19</sup> The reserve margin of MAPP was an adequate 14%. Table 2-9. Despite extreme price spikes in 1998 and 1999, during which unprecedented bulk transactions occurred, the midwest did not institute price caps, which is cited as the single reason for increased generation construction in the area. Id., 2-15. With this information, the totals of TLRs may be compared with other regions: From 1998-2000, MAPP had 17 TLRs, while SPP had 72, ECAR 287, and MAIN the highest number at 309. The only Minnesota flowgate where TLRs above level 3 were called in Summer, 2000, was the Prairie Island-Byron 345 kV line, which had 2 TLRs, only one of which had a reported curtailment, and that curtailment was only 179 MW, out of a total in the MAPP region of 1202. The only other MAPP flowgate reporting curtailments was NPPD's Cooper line, which had curtailments equaling the MAPP balance of 1023 MW. Id., Table 2-11, p. 2-

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<sup>19</sup> Over 3,000 MW of new capacity is planned for MAIN in 2,000, and even more capacity will be added in 2001. Ex. 246, NERC Reliability Assessment 2000-2009, MAIN Assessment, p. 59.

21. The MAIN Flowgates do not even list the Eau Claire-Arpin line as presenting any curtailments above TLR level 3 whatsoever. Table 2-11, p. 2-20. ATC witness

Terhune admits TLRs are decreasing:

MAIN regional reliability council records publicly available on their web page indicate that the WI-MN 345 kV interconnection experienced transmission loading relief incidents in the last three calendar years as follows: 134 in 1997; 78 in 1998; and 64 in 1998.

Terhune, Dir. p. 9, r. at 4448.

The report notes that "the Midwest region is dominated by vertically integrated transmission providers, each having control over their own transmission and generation functions, serving their own native load." Id. at 2-31. However:

During this investigation, Staff received many complaints from market participants alleging barriers to transmission access, including TLR curtailments, lack of standardized protocols for providing information, particularly ATC handling interconnection requests, and discriminatory conduct. We have been able to substantiate some of these complaints. But certain key data to analyze some of the issues, such as the causes of the TLRs, either are unavailable at this time from the NERC regions a/or key transmission providers (e.g., coincident peak load data for the summer of 2000) or not maintained at all (e.g., import/export data). The fact that these data were not readily available prevents an assessment of whether markets are functioning efficiently.

Because of the inability to obtain critical information concerning general problems, such as the causes of TLRs, we are unable to definitively determine whether transmission access problems are systemic and widespread in the Midwest or whether the problems represent a collection of isolated incidents. Because of this lack of clarity, we were also unable to determine whether the appropriate regulatory response to these problems should be more aggressive enforcement of existing rules (if the problems are isolated incidents) or whether the rules need to be adjusted (if the problem is systemic).

The lack of this information, in itself, creates a market inefficiency, because neither market participants nor regulators can fully analyze market conditions in real time in order to make decisions on what actions to take.

Id., p. 2-31.

The policy options presented as solutions to the institutional problems were to

standardize protocols and procedures, improve information on market performance, standardize procedures for system impact studies and interconnection requests, investigate allegations of market abuses and discriminatory conduct, and to improve incentives for open access to transmission. Id., 2-49 & 49. The Commission must also regulate the balance between market considerations and preservation of grid stability to the extent of its jurisdiction:

As long as the Commission allows utilities to maintain some of their reserves in the form of imports of firm power contracts, that capability must not be threatened by the risky operational management of the line.

Rosen, Tr. at 5451-2.

In addition to the institutional problems of power transmission and distribution which are the result of heavy loading, the grid is increasingly unstable because heavy loading increases the need for reactive power. The grid requires reactive support for stability, and the production of reactive power conflicts with the production of real power creating yet another institutional problem:

Unlike real power (MW), the reactive component of power (Mvar) cannot be easily transmitted over distances and must be supplied locally. Without adequate reactive support, parts of the system can be susceptible to potential voltage collapse or instability...

Many utilities made concerted efforts to improve reactive support as demand grew by adding shunt capacitors on their distribution and subtransmission systems. However, there may have been a falloff in maintaining such distribution reactive improvement programs in recent years...

When heavy power transfers occur across a transmission system interface and transmission lines are heavily loaded, voltage in the area of the interface can become depressed if sufficient reactive supplies are not available to the system

**There is currently no incentive to increase the levels of reactive support on the bulk power systems. In fact, there are disincentives, because**

**generators are paid to produce real power, not reactive power.**

If the institutional problems presented in this report are not addressed, and industry history provides reason only to believe they will be ignored, the institutional problems will be exacerbated by the construction of additional transmission capacity for bulk power transfer.

**IV. THE PURPOSE OF THE ARROWHEAD-WESTON LINE IS TO PROVIDE APPLICANTS WITH THE OPPORTUNITY FOR INCREASE “MARKET” OR “ECONOMY” TRANSACTIONS AND NOT FOR ANY PUBLIC PURPOSE.**

There is no basis for a determination by the Commission that this line is needed or that it is in the public interest because it is not -- it is being built for private corporate pursuit of private corporate gain in a partially deregulated market. The record shows that there will be little reliability benefit, particularly where upgrades required to provide the reliability benefit are not part of the application, the “need” for transfer capacity in WUMS is fallacious, and the line is not the most economical means to address the phase angle problem. So why build the line? Presently, the applicants have very little bulk power transmission capacity. In testimony, the applicants admit that the Arrowhead-Weston line has the potential for vastly increasing the percentage of bulk power transfers within their system. That economic fact in the changing electricity market provides ample incentive for the applicants to build this powerline. However, that is not a sufficient basis for issuance of a Certificate of Public Convenience and Necessity.

This line provides capacity that would be used **.92 days per year**. See Smies, Rebuttal, p. 17, Tr. at 4134 (emphasis added). But the line will be available for use the remainder of the year, for economy purchases from outside sources, as

applicants admit:

**If the investment is in a line, however, that investment will not only serve as an insurance policy, but will give Wisconsin ratepayers access to external markets and the opportunity to take advantage of lower cost sources of energy when they are available.**

Id. (emphasis added). It will be available for use 364.08 days/year, for increased access to external markets and the opportunity to take advantage of lower cost sources of energy, all to the applicants' benefit and to the benefit of other utilities in WUMS. Ex. 199, 11/12/99 Letter from WPS (p. 2, para. 1, list of utility beneficiaries of project); c.f. Miller, Tr. at 4703(MG&E, Minnesota Power, Wisconsin Power and Light and WPPI benefactors of Arrowhead-Arpin in Advance Plan 8).

What could the applicants expect in increased revenues? Shortly after submitting its application, WPS began to track revenues to be made from economy power purchases, and, as importantly, potential revenues lost when transfer capacity was not available – not available to serve its native service territory, but not available to make economy power purchases:

WPS generation control area operators started collecting detailed information on an hourly basis since February 2, 2000, to document the transmission constraints which they have to deal with on a daily basis. On an hourly basis the operators have documented “next hour transmission service availability.” From this data, WPSC generation operators have identified for “weekday on-peak” and “all hours” periods the availability of transmission which WPSC generation operators can use for **economy power purchases (above current firm contracts)**, as well as emergency purchases which may be needed during unit outages at high system load levels.

Smies, Direct p. 10, Tr. at 4104 (emphasis added). It was clarified that the witness was representing non-firm capacity available, “above our firm reservation for one of our purchases that we count towards our reserves.” Smies, Tr. p. 4188-9.

Applicants claim that 56 percent of the time during weekday peak periods there was no transmission capacity available.

Q: Has there been any estimate of the magnitude of commerce and electricity that's lost or constrained by this interface?

A: I don't have the exact amount. It's clearly in the millions of dollars because those curtailments have occurred day after day after day after day and the impact simply in the merchant arena, areas of relatively low cost production and areas of very high cost production.

Terhune, Tr. at 4555. When this is quantified in a dollar figure, the admitted effect of limitation of transfers is staggering – the “net economic benefits, that might have been achieved by allowing firm economic transfers with capacity across the western interface versus prohibiting those transactions” was calculated by the witness to be between \$16 and \$88 million, and given the mix of transactions, he “got something that looks like \$16 million in terms of benefit,” on the low end of his range. Smies, Tr. at 4251-2. Applicants complain that:

The data shows that for a substantial portion of 2000, WPSC was effectively isolated from resources that could possibly have been a source of lower cost energy...

Smies, Dir. P. 10, Tr. at 4105. Given the uncertainty in the utility regulatory structure, that could change:

Q: And really, what this proposal, what this whole proceeding is all about, isn't it, is just what is the appropriate infrastructure for providing electric utility services in the future considering the continuum to competition. Would you agree with that?

A: I think that's part of what we're here to talk about, yes.

Borgard, Tr. at 3428.

Q: This line will support increased economic transfer capability, won't it?

A: I think it has the potential to do that, yes.

Borgard, Tr. at 3455. As to whether the marketplace will utilize this capacity:

A: The application makes no assumptions regarding how the market place might utilize the additional capability afforded by this line.

Q: But if one does believe in the market, wouldn't the market operate efficiently and use that capacity?

A: I believe that one of the ancillary benefits of this project that I mentioned earlier was the ability to access external energy markets when economics dictate it.

Q: Is that a yes?

A: The line will allow – an ancillary benefit of the line is to allow access to external energy markets.

Plante, Tr. at 3716. However, taking advantage of this economic “ancillary” benefit will undermine the purported reliability of the Arrowhead line:

To that the extent that need for increased new import capacity adequate to address these reliability concerns justifies a new line, allowing that incremental import capacity to be used to facilitate substantial increases in firm economic transactions will undermine the achievement of the reliability considerations justifying the construction of the new line. In effect, justifying and building a new EHV line primarily for firm economic transaction benefits will compound the reliability problems in the future for Wisconsin, just as it did in the crisis period of 1997-1999 by helping to insure that there are inadequate in state generation resources and inadequate transfer capacity to handle contingencies when and if they occur.

Edgar, Dir. P. 3, Tr. at 6052. Where a powerline is “needed” 0.92 days/year, and is available, as an “ancillary benefit” for use for economy transactions 364.08 days per year, the line will be used to facilitate substantial increases in firm economic transactions. See Smies Rebuttal, p. 17, Tr. at 4134; supra p. 6. This will be a windfall for the utilities.

When asked the percentage of WPS' revenues were currently derived from



wheeling:

A: But as Mr. Borgard mentioned the WPS system itself is an electrical cul-de-sac and we do not entertain that many wheeling transactions across our – what used to be our transmissions system.

Q: So then logically if you are this cul-de-sac and then you do build the super highway, you will have much higher revenues in wheeling, correct?

A: I'm not sure that I can anticipate how the market will evolve in the future...

Q:... The line would provide the opportunity however, for an entity to generate increased – substantially increased revenues, correct?

A: The line would certainly allow additional wheeling transactions and as Mr. Borgard discussed earlier, the revenue from that or any additional revenue from those wheeling transactions are actually credited back to the revenue requirement of the entire system.

Plante, Tr. at 3716-7.

Q: And you recall the testimony, ample testimony on the ancillary benefits of economic transfer?

A: Yes.

Q: They exist, don't they.

A: **Yes, yes.**

Smies, Tr. at 4263 (emphasis added). "... the line is also likely to provide significant economic benefits on a non-firm basis..." Landgren & Terhune Surrebuttal p. 8, Tr. at 4457 (emphasis added). Although Applicants do not want to admit the potential for revenue generation windfalls associated with the line, it is undeniable. Applicants also reluctantly admit that the line is needed for and could be used for transmission of increased or new generation at mine mouth and hydro plants. Smies, Tr. at 4134, 4146. Efficient economics demands that the line be utilized to its fullest extent.

Applicants agree that “competing corporate interests in electric markets produces a fundamentally different dynamic than providing utility services according to regulations in a conventional regulated market.” Borgard, Tr. at 3433. But what Applicants would like to disregard, and which the Commission must not disregard, is that Wisconsin is still a regulated market. Dr. Rosen, addressing the need for least cost planning, raises this fact:

**Well, we all enjoy different experiences, but least-cost planning is obviously still essential to carry out for transmission line, you know, certification hearings and dockets because transmission is still a regulated function of regulated utilities. It is in Wisconsin, it is everywhere. And there is – as far as I’m aware, there is no lines yet in the United States that are unregulated. That may change soon, but not likely in Wisconsin.**

Rosen, Tr. at 5590(emphasis added).

The market remains regulated and Commission has the duty and authority to review this project and make a determination it is in the public interest. It is not a reasonable decision to permit a powerline for 0.92 days annually thereby providing for availability 364.08 days annually to utilities for utility benefits of economy transfers, nor should the infrastructure expense for this windfall utility benefit fall on ratepayers.

**V. APPLICANTS ARE NOT ENTITLED THE REGULATORY BENEFIT OF EMINENT DOMAIN BECAUSE THIS PROJECT IS NOT NEEDED AND IS NOT IN THE PUBLIC INTEREST.**

There is no basis for Commission issuance of a Certificate of Public Convenience and Necessity (CPCN) for the Arrowhead-Weston line because the project is not in the public interest – the benefactors of this project are utilities – and the applicant corporations, MP and WPS have no right to eminent domain under the statutes and case law of the state of Wisconsin where the purpose of the project is not a public

service corporation providing a public service. ATC, a transmission company, has no power of eminent domain under Wisconsin law.

A CPCN is the trigger for eminent domain proceedings under Wisconsin statute:

A certificate of public convenience and necessity issued under s. 196.491(3) shall constitute the determination of the necessity of the taking for any lands or interests described in the certificate.

Wisc. Stat. §32.07(1). The state grants the power of eminent domain to utilities on the basis of their status as public service corporations, which have as a purpose the generation, transmission, and distribution of electricity to a defined and exclusive service territory as a regulated monopoly. Wisc. Stat. §200.01(2); see also Wisc. Stat. §196.01; see also Schoengold, Tr. at 5350. The state's statute definition includes a holding company as a utility as a public service corporation, but it is very clear that a transmission company such as Intervenor American Transmission Company is not a public service corporation:

**“Public service corporation” does not include a transmission company as defined in s. 196.485(1)(ge).**

Id. For the purposes of an application for a Certificate of Public Convenience and Necessity:

“Transmission company” means a corporation organized under ch. 180 or a limited liability company organized under ch. 183 that has as its sole purpose the planning, constructing, operating, maintaining and expanding of transmission facilities that it owns to provide for an adequate and reliable transmission system that meets the needs of all users that are dependent on the transmission system and that supports effective competition in energy markets without favoring any market participant.

Wisc. Stat. §196.485(1)(ge).

Regulation of utilities began:

...where for one reason or another the competitive marketplace was viewed as not being the appropriate way of controlling the predatory practices of an industry, of a provider.

And so regulation was put into place to essentially serve the purpose that competition would otherwise have served if it were a situation where competition would work.

Schoengold, Tr. at 5351.

In a regulatory bargain, utilities submit to regulation in part due to high infrastructure costs and the obligation to serve, and they are granted monopoly status. See Wisc. Stat. §200.01(2). Utilities have a requirement of nondiscriminatory rates, and a requirement of agency approval to construct facilities, and must comply with recordkeeping and accounting requirements. Schoengold, Tr. at 5352. Regulation confers benefits on utilities, in addition to the power of eminent domain, including the opportunity to realize a rate of return for their investments.

The utilities' power of eminent domain is broad:

To exercise the power of eminent domain and to condemn lands or any interest in lands including water power, whether located within or without the district, whenever the same are necessary for the construction, operation, improvement or extension of any utility owned, or to be owned by the district and, in that behalf, to authorize condemnation proceedings to be instituted and prosecuted by the general counsel of the district in the name of the district and at its cost and expense and otherwise in the manner prescribed by law.

Wisc. Stat. §198.14(8); see also Wisc. Stat. §66.073(6)(i). Eminent domain may be exercised by:

Any Wisconsin corporation engaged in the business of transmitting or furnishing heat, power or electric light for the public or any foreign transmission provider for the construction and location of its lines or for ponds or reservoirs or any dam, dam site, flowage rights or undeveloped water power.

Wisc. Stat. §32.02(5)(b).

Eminent domain allows utilities to condemn land for their use when a project has been deemed "needed" by the state, and saves utilities the time, expense and uncertainty of negotiating market rate purchases and easements for infrastructure. Wisc. Stat. §32.07(1). Utilities may exercise their power of eminent domain where it is "proper for the accomplishment of the desired public purpose." Falkner v. Northern States Power Co., 248 N.W.2d 885(Wisc. 1977). "Public" is defined in case law:

...the word "public" meaning all those who require power and are willing to pay reasonable rates therefor to the full extent of the capacity of the enterprise.

Wisconsin River Imp. Co. v. Pier, 118 N.W. 2d 857(Wisc. 1908).

A taking for a use that is not public is unconstitutional and beyond the right of even the legislature to accomplish.

Falkner v. Northern States Power Co., 248 N.W. 2d 885, 891 (Wisc. 1977); see e.g., Wisconsin Water Co. v. Winans, 54 N.W. 1003 (Wisc. 1893); Schumm v. Milwaukee County, 45 N.W. 2d 673 (Wisc. 1951); David Jeffrey Co. v. Milwaukee, 66 N.W. 2d 362 (Wisc. 1954); Cincinnati v. Vester, 50 S.Ct. 360 (1930). Public purpose must be established with certainty prior to condemnation:

The right to condemn is an attribute of sovereignty and is often indispensable for the common good, but it is, nevertheless, so harsh a right that even the sovereign may not exercise it unless the public purpose is clear and the public use, for which the private owner is to be compelled to surrender his property, is assured.

Schumm v. Milwaukee County, 45 N.W. 2d 673, 676 (Wisc. 1951).

Because the regulatory climate and nature of the industry are changing, with federal policy deregulating wholesale market transactions, and with utilities dreaming of outright deregulation of the entire industry, many projects are not necessarily in the public interest. Instead, projects proposed by utilities can be "mixed-purpose" projects

which contain a large component of utility self-interest and self-dealing, and in some cases projects are entirely for corporate interest and not public purpose, which alters the balance of the traditional basis for regulatory benefits:

To the extent economy transactions occurred, all customers benefited. As such, the use of eminent domain (the legal basis by which land may be acquired for public use) to acquire the rights-of-way these lines used was acceptable.

The changing electric market may be breaking down the social compact behind the principle of eminent domain, affecting new transmission line construction and may change the way in which reliability is maintained. Public opposition to the construction of transmission facilities and regulatory uncertainties for cost recovery on transmission investments limit new transmission facility additions...

...The segments of the population impacted by the new transmission line construction will not be the same segments that are benefiting from the profits the new lines create. This disparity will increase the legitimacy of the political opposition to new transmission line construction. The fragmentation of the industry into segments not easily identifiable with the familiar local utility may make matters worse. The step to limiting the power of eminent domain (to, say, lines with a demonstrable public, rather than private, benefit) may be an easy one for legislators.

Ex. 246, NERC Reliability Assessment, 2000-2009, p. 33.

Schoengold elaborates on the NERC assessment of public purpose and addresses the importance of identification of benefactors of transmission lines in the emerging market economy and the appropriate method of compensation of landowners:

Historically transmission primarily served a purpose of connecting systems together for the purpose of improving reliability through the sharing of reserves and reducing cost for customers by providing access to lower cost power sources, either on a firm or economy basis. In most cases the major benefit of the transmission lines was the improvement in reliability. In any case, the utilities recovered their cost for building and operating the lines, and the benefit of the lines in terms of improved reliability and reduced operating costs went almost entirely to the customers. As the new market economy for electricity is

developing, this is no longer the case. More and more, the purpose of transmission lines is focused on increasing the number and size of power transactions. In many cases the benefits of these transactions go, not to the customers in general, but to private owners of generating facilities, to power marketers, and to specific, selected customers. **We can no longer assume that the benefits of transmission lines flow to the general populace.**

**Schoengold, Dir. p. 26, Tr. at 5243. According to Schoengold, a project's public purpose matters because:**

I believe that the fundamental change in the purpose and use of transmission undercuts the traditional basis on which decisions were made which, essentially, forced landowners to accept transmission facilities on their property. Since transmission was built for the general good of the public, it was considered acceptable to require landowners to accept these facilities for the public good.

Id., Dir. p. 26-7, Tr. at 5243-4.

While the Arrowhead project may confer some as yet undetermined reliability benefit to the public, regarding "[t]he economy benefits, it's not clear that they will get." Schoengold, Tr. at 5315.

It depends on the way the rate cases are done. It depends upon how the power is bought in the market. It depends upon whether or not there is retail access. So I think we can no longer say that they will get the economy benefits of the line.

Id. Distribution of any economy benefits of the line are determined by a rate case:

Again, that depends on the way the rate cases are organized, it depends upon how – what kinds of decisions the commission makes in the new fuel rules, cases that they're reviewing. It may well be that the economy benefits will go more to the shareholders of the utility or to the owners of the generation than to the ratepayers...

Well, the commission is moving more and more away from regular rate cases. They're moving more and more towards putting things into fuel rules such that they benefit the – they give more benefits to the utility and less to the customers. And the more that that takes place, the less likelihood that customers will gain a benefit from economy energy on the line, particularly if the way that the lines get used is so that the – more money goes to the independent developers of the projects...

But we're already on the way towards moving towards more use of markets and competition so that many of the processes that were – that used to be in place by which the ratepayers got those benefits have already been eliminated.

Id., p. 5315-7.

[T]he benefits of the proposed line are not the same as the traditional benefits of transmission lines under the old regulatory approach. Under the old regulatory approach, the benefits of transmission went to all of the customers of the electric utilities. Under the new market-based electric industry as recognized by Mr. Smies, the benefits of the proposed line go to the market participants such as the private owners of generation. That is why I believe that the old methods of acquiring and paying for transmission rights of way can no longer be justified.

Schoengold, Surrebuttal p. 5, Tr. at 5256.

When asked whether construction of transmission lines confers benefits in the form of lower rates to ratepayers, specifically whether “any utility capital investment project has resulted in lower rates to consumers,” Schoengold replied:

... I can't think of any case that I dealt with where making a capital investment has led to lower rates.

Id., Tr. at 5343.

This project has a private purpose. The applicants admit that the beneficiaries of these lines are the eastern Wisconsin utilities, and that costs of this line are not recoverable through the rates as is possible for a typical project

The Parties recognize that **the Project is being built to address the regional need for additional transmission facilities and that the traditional regulatory rate recovery methods do not adequately provide recovery of the costs from the entities that benefit from the Project.** Therefore, the Parties agree to develop and seek approval of a method by which the costs of the Project are allocated among users and beneficiaries of the Project. **We agree that these beneficiaries are, at a minimum, all eastern Wisconsin utilities, including WPS, Alliant (Wisconsin Power & Light), Wisconsin Electric Power Company and Madison Gas and Electric Company.** We agree to develop and seek a cost recovery method where under MP includes the portions of the Project located in Minnesota (i.e. approximately 10% of the total Project costs) in its



transmission network, and that revenue requirements related to the Minnesota portion of the Project will adequately reflect the benefits of the Project to Minnesota Power customers. We agree to jointly develop and seek regulatory approval of a method by which other parties including entities which will benefit indirectly through increased transfer capability and relief of congestion on other lines will pay an equitable portion of the Project revenue requirements. It is understood that the foregoing principles for cost recovery from beneficiaries will apply to the extent that revenues from scheduled transactions do not adequately recover the annual revenue requirements of the line.

Ex. 199, 11/12/99 Letter from WPS, and Sample Letter of Support for Project, p. 2 (emphasis added); c.f. Miller, Tr. at 4703 (MG&E, Minnesota Power, Wisconsin Power and Light and WPPI benefactors of Arrowhead-Arpin in Advance Plan 8). In this case, it is not the public that will benefit from the project, the benefactors are a number of utilities, applicants included. Id.

When utilities are the primary benefactors of a project, the project has a private use benefit:

What I mean by that is that as more and more of the transmission system is being used for what I guess I would call private, more private transactions where you've got maybe a non-utility generating power, selling it to a purchaser onto a structure where the benefits of those transactions may not necessarily flow to the ratepayers, then the lines take on more of a – for that portion of the transactions, more of a private use benefit rather than a public use benefit.

Schoengold, Tr. at 5354.

When asked his professional opinion as whether he viewed the Arrowhead project as having a public purpose Schoengold testified:

**I would say on balance I would view it as not a public purpose. There may be elements of public purpose to it, but on balance, not.**

Schoengold, Tr. at 5353; 5368. When asked whether “this line is primarily intended to facilitate private transactions in the energy market:”

It's my view that lines, this line and others like it will end up getting for the most

part used for the purpose of making private transactions.

Schoengold, Tr. at 5372. An ATC witness agrees with this characterization of purpose when he testifies that the line is at best necessary for “reliability purposes” only 0.92 days per year, and that the balance, 364.02 days annually, it is available to utilities for market transactions.” See Smies, Rebuttal, p. 17, Tr. at 4134. Market transactions 364.08 days per year out of 365 means that the project is “getting for the most part used for the purpose of making private transactions.” Id.

The utilities admit that “the Project is being built to address the regional need for additional transmission facilities” and that “traditional regulatory rate recovery methods do not adequately provide recovery of the costs from the entities that benefit from the Project,” the utilities listed above. Ex. 199, 11/12/99 Letter from WPS, and Sample Letter of Support for Project, p. 2. This project is not a “public purpose” project, where the “public” is defined as “all those who require power and are willing to pay reasonable rates therefor to the full extent of the capacity of the enterprise.” See Wisconsin River Imp. Co. v. Pier, 118 N.W. 2d (Wisc. 1908). It is not a “public purpose” project where the public has no access to the economic benefits and the benefits flow to utilities. See Schoengold, Tr. at 5343.

Where a project does not have a public purpose and is not in the public interest:

In areas where utilities are no longer subject to regulation, then whatever benefits that they might otherwise receive from regulation I think are appropriate for them not to get any longer.

Schoengold, Tr. at 5356. Wisconsin’s Supreme Court has held that eminent domain is not available where the project is for a private use. In reviewing a petition for

eminent domain, where a water company wanted to condemn land to pipe water from its well to its facility, the court found:

For aught that appears, such pipe line may terminate at such city limits, or the water to be conducted through the same be there put to private use. There can be no public use, except in supplying the city or its inhabitants with water for the uses and purposes mentioned...It is entirely unlike a railroad, which is used by the public along the whole line.

Falkner v. Northern States Power Co., 248 N.W. 2d 885, 891, fn. 4 (Wisc.

1977)(quoting Wisconsin Water Co. v. Winans, 54 N.W. 1003, 1007 (Wisc, 1893). In

this case, the powerline is the pipeline which will pass through communities that have no access to the benefits, and will flow to the utilities for their private benefit.

The Arrowhead project is being proposed to fulfill a public need or interest. It is admittedly being built to address the applicant's claim of regional need for bulk power transmission capacity, passing through the area as in Wisconsin Water, with no opportunity for those affected by eminent domain or the public to use the facility or receive benefit from it. The project cost will not be covered by the traditional regulatory rate recovery methods, and applicants are searching for a way to recover costs from the entities that benefit from the Project, the "eastern Wisconsin utilities." Because there is no public use and the benefactors are utilities and not the public, and because the costs of the project are not paid by "all those who require power and are willing to pay reasonable rates therefor to the full extent of the capacity of the enterprise," there is no basis for a determination by the Commission that the Arrowhead project has a public purpose or is in the public interest.

The Commission has the authority to and must make a specific determination that this project is in the public interest:

And presumably the commission could make a decision in this case that the line might be valuable but may not meet the public interest standard that the condemnation rules or condemnation laws call for.

Schoengold, Tr. at 5318, 5354; see also Wisc. Stat. §196.491(3). Based upon the record, the Commission must determine that this project is not in the public interest and must not issue a Certificate of Public Convenience and Necessity.<sup>20</sup>

**VI. THE COMMISSION MUST DENY THE APPLICATION BECAUSE THE PROJECT PROVIDES FACILITIES UNREASONABLY IN EXCESS OF THE PROBABLE FUTURE REQUIREMENTS.**

The Commission must not certify the Arrowhead project because the applicants grossly overstate need for the facility, and if built, will provide transmission far in excess of requirements. Under Wisconsin law, if a project provides facilities unreasonably in excess of the probable future requirements, the Commission may refuse to certify a project. Wisc. Stat. §196.40 (3)(b)2. The Commission must also comply with certain Advance Plan 6 Orders regarding transfer capacity across an interface:

- 10.1 Wisconsin utilities may plan on the basis of up to 1200 MW of transfer capacity across the interface. Options 2, 3, 4 and 6 listed in the Interface Study and shown in Appendix 10A are approved for planning purposes at transfer capacity levels up to 1200 MW.
- 10.2 In construction authority cases, evaluation of options affecting the interface will not recognize benefits due to transfer capacity in excess of

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<sup>20</sup> Intervenor Wisconsin Central, Ltd., expresses concern that the project will have a significant impact on its facilities, and that applicants may attempt to exercise eminent domain to obtain easements over its property. WCL, Br. P. 1. Utility powers of eminent domain are preempted by federal law if the utility's condemnation interferes with WCL's efforts to provide rail service, including acquisition and use of a railroad's property. See e.g., City of Auburn v. United States, 154 F.3d 1025, 1031 (9<sup>th</sup> Cir. 1998), cert. Denied, 119 S.Ct. 2357 (1999); see also Wisconsin Central Ltd. V. City of Marshfield, 200 U.S. Dist. Lexis 10570 (W.D. Wis. 2000). These concerns must also be addressed by the Commission.

1200 MW.

Order, p. 120, Advance Plan 6, Docket No. 05-EP-6.

A recurrent theme in this application is the applicants' overstatement of need. That overstatement is best demonstrated by applicants admission that the Arrowhead line would be used 0.92 days annually for reliability purposes, admitting that the balance of the year, 364.08 days, the line would be available for the private use of utilities for market economy transactions. See Smies, Rebuttal, p. 17, Tr. at 4134. Many other more reasonable means are available to address issues applicants complain of, means which are less expensive, and means which encourage electrical independence from fossil fuels and central station generation.

In Advance Plan 6, two orders were issued that address transfer capacity across an interface. Under these orders, transfer capacity in excess of 1200 MW across an interface will not be recognized. The applicants proposal is for transfer capacity far in excess of 1200 MW, and have done nothing to distinguish the benefits of the permitted 1200 MW from the transfer capacity as proposed. The Commission must not recognize any benefits attributable to transfer capacity of the proposed Arrowhead project over 1200 MW.

**VII. THE PROPOSED POWERLINE IS NOT IN THE PUBLIC INTEREST WHEN ALTERNATIVES TO THE LINE ARE CONSIDERED**

There is no basis for a determination by the Commission that the design of the line is in the public interest when considering alternate sources of supply, which must be considered as a part of an application for a Certificate of Public Convenience and Necessity. Wisc. Stat. §196.491(3)(d)2. Alternatives to the project must also be

considered in light of the states mandated Priorities, which mandate:

In meeting energy demands, the policy of the state is that, to the extent cost-effective and technically feasible, options be considered based on the following priorities, in the order listed:

- a) Energy conservation and efficiency.
- b) Noncombustible renewable energy resources.
- c) Combustible renewable energy resources.
  1. Natural gas
  2. Oil or coal with a sulphur content of less than 1%.
  3. All other carbon-based fuels.

Wisc. Stat. §1.12(4). Wisconsin statutes also require that:

- a) In designing all new and replacement energy projects, a state agency or local governmental unit shall rely to the greatest extent feasible on energy efficiency improvements and renewable energy resources, if the energy efficiency improvements and renewable energy resources are cost-effective and technically feasible and do not have unacceptable environmental impacts.
- b) To the greatest extent cost-effective and technically feasible, a state agency or local governmental unit shall design all new and replacement energy projects following the priorities listed in Sub. (4).

Wisc. Stat. §1.12(5)(a),(b). There is nothing in the application or the record to support a determination by the Commission that the mandates of Wisc. Stat. §§1.12(4),(5) have been considered or addressed. There is much evidence in the record to support a finding that these mandates have not been considered.<sup>21</sup> Reasonable alternatives such as the low-voltage option, distributed generation and cogeneration, stand-by generation, and DSM and other conservation based options are available that have a

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<sup>21</sup> When MEUW, the benefactors of the line, were asked whether the priorities of Wisc. Stat. §1.12(4) were the same priorities as MEUW's, MEUW's representative replied, "I don't know." Benforado, Tr. at 4790. Miller was unfamiliar with the energy priorities of the state. Miller, Tr. at 4707.

significantly lower cost than the powerline project.<sup>22</sup> These alternatives can and must be used to solve the “problem” in compliance with Wisconsin’s hierarchy of priorities.

**A. THE LOW-VOLTAGE ALTERNATIVE IS A REASONABLE ALTERNATIVE THAT PROVIDES EQUIVALENT BENEFITS WITH LOWER COSTS**

An alternate option to the Arrowhead line was developed by PSC-WI staff and was presented in the PSC-WI's Environmental Impact Statement as required for adequate transmission planning:

Planning for the 100 kV and above system cannot be carried out without consideration of 69kV system problems and their solutions. Consideration must also be given to problems and solutions on the system below 69 kV down to the 30 kV ranges where these facilities serve a transmission function.

Criteria for Transmission Network Planning and Design, AP8, D23b-5, No. 10 (quoting AP-4 Order Point 46).

This option was formulated by using the WIRE's and WRAO information relied upon by Applicants for their proposal. Leovy, Tr. at 6114-6. Called the "Lower-Voltage Reinforcement" alternative:

The proposed changes in this option would require rebuilding or upgrading about 131 miles of existing transmission and sub-transmission (46 kV) lines. Minimal, if any, new ROW would be required for most of these upgrades. About 40 miles of new line could be double circuited with existing facilities. The addition of some of these new lines could require an expansion of the existing ROW. Finally, the Lower-Voltage Reinforcement alternative includes four new transmission lines (Chisago-Apple River, Sunrise Tap-McCue, Hillsboro-Reedsburg and Maine-Brokaw) resulting in about 66 miles of new construction in Wisconsin. A portion of several of these new transmission lines could also be double circuited with existing lines.

Ex. 172, EIS, p. 186. Some of the projects identified are already approved or are in the approval process. Id.; see also Leovy Dir., p. 11, Tr. at 5966. This option was

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<sup>22</sup> MEUW presented resolutions in support of the Arrowhead project to its members, but did not present alternate means of meeting the claimed need. Benforado, p.

analyzed using the WIRES methodology, first setting import limits with “an approximate, linear extrapolation technique, and then following up the results with “a non-approximate technique...to test the results of the preliminary analysis.” Id., p. 174.

The Low-Voltage Reinforcement option provides relief from the import/export capacity and phase angle problems complained of by Applicants. The EIS notes that this alternative “appeared to be capable of achieving transfer levels near the 3,000 MW criterion used in the WIRE study and “could provide approximately 80% of the import capability associated with the Arrowhead-Weston 345 kV line.” Id., p. 173, Table 4-14; p. 174; p.187, n. 128. Through its reliance on a larger number of smaller lines, “it could conceivably come out more favorably...” Leovy, Tr. at 6120-1

The Low-Voltage option also improves the Arpin phase angle problem:

Commission staff analysis, however, indicates that, with the improvements identified in Table 4-14, the phase angle problem should not prevent immediate reclose at import levels up to 1,000 MW from the south and 1,400 MW from the west. Since imports from the west have the greatest impact on the Arpin phase angle, it can be assumed that immediate reclose of this line could also be accomplished at import levels of 1,400 MW from the south and 1,000 MW from the west.

Ex. 172, FEIS, p. 176; see also Leovy, Tr. at 6112.

Plan 12, a WIRES low-voltage alternative consisting of a number of upgrade projects, “nearly provides the transfer capability objective of this study,” but was rejected because it “does not perform well when the Arpin phase angle and system loss savings are considered.” Ex. 171, Application, p.24. However, it appears that the primary reason it was rejected was:

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4782.



because Plan 12 does not establish a new high voltage tie across the western interface, will not eliminate the need for an Arpin flow limit which will severely limit transfer capability.

Id. The theme of Applicants' rejection of Plan 12 is that the low-voltage option of Plan 12 does not provide the transfer capability that Applicants desire, demonstrating that the purpose of the project is establishing the new high voltage tie across the interface and increasing transfer capability.

Plan 14 of the WIRES report was also a low-voltage option, and the study group did not adequately consider it and their conclusions were unsupported:

Q: Why did the WIRES phase I group eliminate that option even though it was within approximately 100 megawatts of 3,000?

A: It was the consensus of the experts involved in the WIRES study group that the nonthermal limitations that we were attempting to address, that is the Arpin phase angle problem, the dynamic stability issues in the Twin Cities area, the voltage stability issues were not addressed with the lower voltage reinforcement options.

Q. And was it the judgment of these experts that you didn't need to actually model that to determine that?

A: Yes.

Plante, Tr. at 4074.

A Low-Voltage Reinforcement Alternative is a reasonable method to achieve reliability improvements to address the problems complained of by applicants, and it is a far less expensive option than the Arrowhead project.

**B. NEW DISTRIBUTED GENERATION IS A REASONABLE ALTERNATIVE THAT PROVIDES EQUIVALENT BENEFITS WITH LOWER COSTS**

Distributed generation in the WUMS region, but also all of Wisconsin, would alleviate any shortage of supply and circumvent any capacity constraints. When asked

whether the Applicants had analyzed "potential for distributed generation plus conservation coupled with low voltage upgrades to serve the same needs as the proposed Arrowhead-Weston line," WPS' Larry Borgard testified that it had been addressed in the EIS, which is not a utility document. When asked specifically whether there was a utility report, analysis, or other document addressing this potential, Mr. Borgard simply responded, "No." Borgard, Tr. at 3448-9; see also Hamacher, Tr. at 4865, 4871; see also Benforado, Tr. at 4797.

On the other hand, Borgard himself has made a presentation on the benefits and uses of distributed generation and admits to the substitutability of transmission and generation. Borgard, Tr. at 3517-8. MEUW admits to the economic development and reliability benefits of distributed generation. Benforado, Tr. at 4801. ATC's Landgren, testifying about the way electricity is traditionally delivered, admits that there is now a trend to smaller generation:

Since that time I think the trend is to smaller generators instead of the 600,000, 1300 megawatt generators...largely because some of the outage experience with large cutting edge technology units that were installed over the 60s and early 70s period. So I would say the trend is to smaller generators than were historically available.

Landgren, p. 4501, 4502-3

The applicants lack of analysis of distributed generation options is also borne out in the listing and narrative of "Reinforcement Options Considered" in the application, which lists only those options considered in WIRES Phase I. Ex. 172, FEIS, p. 21-26.

Distributed generation has the potential of addressing the applicants supply and reliability issues used to justify their project application:

Q: As I understand your testimony then, it's your opinion that the additional generation and the other things that you've talked about will address the adequacy of the – of the system reliability.

A: Yes.

Schoengold, Tr. at 5334-5; see also Loock, Dir. p. 6, Tr. p. 4975

Studies quantify the transmission and distribution benefits or any other benefits of distributed generation:

Yes, one of them was a study that was done at Boston Edison that looked at the comparative cost of – actually what it was looking at was the avoided cost of distribution and transmission with the idea of being that you could then compare putting in localized resources versus building transmission – that would avoid the need for T and D versus building T and D.

And in the case of Boston Edison there were a number of areas on the system where we found that the avoided cost of T and D was much higher than the avoided cost of capacity which essentially means that it was less expensive to build distributed generation in those areas than it was to build the T and D facilities which building those distributed generation units would avoid.

Another study is one, I can't really talk in detail about it because it's for a confidential study for a Midwestern utility, but we're looking at, again, the benefits of distributed resources as a way of avoiding T and D investments. And again, the T and D investments that could be avoided were much more expenses than the distributed resources that would enable the avoidance of those investments.

Schoengold, Tr. at 5348.

Q: If you had a series of distributed generation technologies on line, why, a 115 kV power line may be sufficient to bring power from those facilities to market, wouldn't it?

A: Yes. In fact – yes.

Borgard, Tr. at 3437. This fact was reiterated by ATC witness Terhune:

If every location has built sufficient capacity to meet every peak and in every local area with no transmission of energy or capacity between those areas, the answer would be yes, **you would not need the transmission line** if everyone had local capacity entirely capable of covering their peak and some sufficient

additional reserve capacity to cover the outages of those units.

**Q: Now, I'm asking you, in order to take the energy from that distributed technology and put it into the homes and businesses in that geographic area, do you really have to have a 345 kV powerline?**

**A: No.**

Strategically located distributed generation in Wisconsin, and particularly in the WUMS region, would alleviate any shortage of supply and circumvent any capacity constraints.

**C. COGENERATION IS A REASONABLE ALTERNATIVE THAT PROVIDES EQUIVALENT BENEFIT WITH LOWER COSTS**

Another alternative not adequately addressed by WPS was cogeneration:

Q: Do you have any knowledge about how much untapped cogeneration potential there is within the WUMS area.

A: No.

Q: You have done no analysis of what that potential is?

A: I have not, no.

Q: Has anybody in WPS?

A: I don't know the answer to that question.

Borgard, Tr. at 3444.

The Wisconsin Paper Council's representative, speaking for 28 members with approximately 40 manufacturing plants, testified that "papermaking is the state's largest industrial electricity consumer." Gustafson, Dir. p. 1, Tr. at 5191; Tr. at 5196. Despite inherent opportunities for cogeneration, when asked what members had done to become less dependant on the transmission grid, Gustafson testified that:

...I don't know that there is a way to reduce dependency on the grid short of

constructing our own power plants and simply going off the grid.

Gustafson, Tr. at 5199. Cogeneration opportunities at paper plants in the Rhinelander loop were not investigated by the applicants. Hamacher, Tr. at 4853.

The applicants have not investigated the significant opportunities for cogeneration available in the WUMS region, particularly at paper plants of the Wisconsin Paper Council, an intervenor in this proceeding. The Paper Council's reliability concerns are disingenuous when it has taken no action to determine whether those concerns could be addressed through cogeneration.

**D. STANDBY GENERATION IS A REASONABLE ALTERNATIVE THAT PROVIDES EQUIVALENT BENEFITS WITH LOWER COSTS**

Another option not addressed by either the applicants or the PSC-WI is that of the use of standby generation. When asked whether WPS had a standby generation program, WPS' Smies testified:

I'm not familiar with a specific program. I know we do have industrial reps that call on our customers. If they voice an interest in it, they certainly work with them as to looking at different options.

Smies, Tr. at 4208; see also Gustafson, Tr. at 5211. However, when asked whether he was aware that other utilities including WPPI, Alliant and MG&E maintain and market standby generation programs, he was not even aware of such programs.<sup>23</sup>

Id.; see also Miller (Alliant), Tr. at 4701; 4710-12. The Wisconsin Paper Council was as unaware of options for backup power:

In short-term, there is really nothing you can do. You expect that reliability. We expect to pay for it, and we want that there. In terms of long-term, people have

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<sup>23</sup> Alliant has truck mounted generators totalling 90 mW. Benforado, p. 4775; Loock, Tr. at 4977. WPL testifies it has installed "90 mW of portable generators at six substations to meet" reserve margins. Miller, Dir. at 13, Tr. at 4686.

just shut down for those hours and wait to start up again. If you don't have electricity, you're not running.

Gustafson, Tr. at 5202-3; see also Tr. at 5214, 5215-6.<sup>24</sup> Although witnesses used the hysterical specter of hospitals without electricity filled with dying patients on unpowered respirators and babies dying in incubators, witnesses admitted that hospitals and clinics utilize standby generation. Benforado, Tr. at 4779; 4786; 4803.

WPS does utilize D-SMES units in Rhinelander, which provide a type of standby support in the form of emergency backup real and reactive power:

Essentially they're storage devices that inject both real and reactive power over a short duration when called upon during things like faults on the transmission line, lightning strikes, things like that but they're very short duration, very quick switching devices.

Borgard, Tr. at 3513. The D-SMES units are regarded as a temporary fix and not a long term fix. Borgard, Tr. at 3516. Use of D-SMES units was evaluated by WPS as an alternative "because it does satisfy the voltage stability or does correct the voltage stability deficiencies that the upper western area has similarly to a Tripoli to Highway 8 line," and additional D-SMES units would eliminate the need for the Tripoli-Highway 8 plan. Hamacher, Tr. at 4869.

WPS also did not address the use of microturbines as standby generation:

I don't know of how widespread the availability of these devices are. When we installed them, they were relatively new and I might describe as a demonstration project but I don't know the full availability, the widespread availability of these devices.

Borgard, Tr. at 3524.

Because the Arrowhead line is planned to be used for only 0.92 days annually

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<sup>24</sup> Gustafson seemed also unaware of uninterruptible power supplies that could be

for reliability purposes, those limited reliability needs could be addressed in a large part by standby generation.

**E. DSM AND OTHER CONSERVATION MEASURES ARE REASONABLE ALTERNATIVES THAT PROVIDE EQUIVALENT BENEFITS WITH LOWER COSTS**

Under Wisconsin statutes, the Commission has multiple mandates to utilize available conservation measures “when making any major decision that would significantly affect energy usage,” and “if the energy efficiency improvements and renewable energy resources are cost-effective and technically feasible and do not have unacceptable environmental impacts.” See Wisc. Stat. §§1.12(2), 1.12 (5)(a). Demand Side Management (DSM) has technical and economic potential that is being overlooked by the applicants. DSM has technical potential where it is “available irrespective of the cost” and economic potential where it “is less expensive than the avoided cost of power.” Schoengold, Dir. at 16, Tr. at 5239. The estimated economic potential of DSM is approximately 2,900 MW, or 28% of eastern Wisconsin’s peak load of approximately 10,400 MW. Id., Tr. at 5241. The applicants have not completed an assessment to determine the available energy efficiency opportunities. Schoengold, Tr. at 5375.

There is a downward trend in utility investment and participation in Demand Side Management (DSM). Schoengold, Tr. at 5341. Much DSM investment by utilities has been legislatively mandated, and utilities have been reluctant to participate. Id., Tr. at 5308.

It’s my experience that lacking commission pressure to undertake serious demand-side management programs, utilities have been less than enthusiastic about doing so. And the degree to which they undertake those programs has in the past has been related much to how much the commission was pushing them.

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installed on sensitive equipment. Id.

Id., Tr. at 5361.

Q: Do you agree that recent reductions in utility DSM investment was attributable in part to the utility's claim that they were preparing for restructuring and competition?

A: I believe that's one of the reasons that was given...

Schoengold, Tr. at 5342.

Yet DSM can provide either a reduction in projected demand or could be characterized as a capacity resource.<sup>25</sup> Id., Tr. at 5302.

DSM is economically viable but the utilities are not pursuing it. Schoengold, Tr. at 5380, 5361-2, 6573. Because the Arrowhead line is planned to be used for only 0.92 days annually for reliability purposes, those limited reliability needs could be addressed in a large part by demand side management techniques. DSM, using even the most conservative of projections, can reduce capacity need sufficiently to address the capacity needs complained of by applicants.

**VII. THE ARROWHEAD LINE IS NOT IN THE PUBLIC INTEREST CONSIDERING ENGINEERING, ECONOMIC, AND SAFETY FACTORS.**

**A. THE ARROWHEAD LINE IS NOT IN THE PUBLIC INTEREST CONSIDERING THE ENGINEERING FACTORS THAT HAVE NOT BEEN ADDRESSED IN THE APPLICATION OR PROCEEDING.**

There is no basis for a determination by the Commission that the Arrowhead line is in the public interest considering engineering. Wisc. Stat. §196.491(3)(d)3. As above, the applicants base their application on the WIREs and WRAO reports and have provided very little in the way of engineering plans, performance studies, analysis, documentation that justifies or supports construction of the line.

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<sup>25</sup> Control areas regard DSM such as interruptible load as capacity. Id., Tr. at 5254.



The state requires a cost benefit analysis demonstrating that the reliability benefits provided by the proposed project are reasonable in relation to the cost of the project. Wisc. Stat. §196.491(3)(d)3t. This has not been provided in this application or as an exhibit in the hearings. Plante, Tr. at 3722; see also Arrowhead-Weston Transmission Project, List of Exhibits, Technical Hearings. Without the cost benefit analysis, there is no factual basis for a Commission determination required by statute. The Applicants have also not provided any demand projections or load flows and dynamic stability studies, on Arrowhead as a stand-alone project and not 3j, to the Commission as a part of their application. Wisc. Code. §111.43(1)(d)4; Plante, Tr. at 3722, 3729. Without demand projections or load flows and dynamic stability studies, there is no factual basis for a Commission determination about whether the project provides reliability benefits. Additional studies are required by MAPP's Design Review Subcommittee, which will not permit a utility to electrify its without review and approval of the project based on the utility application which must include power flow modeling for impact analysis on MAPP's regional constrained paths or other related paths; power transfer distribution factor to determine the impact of the Arrowhead-Weston line on constrained paths; outage transfer distribution factor to address the megawatt flow on the limiting facility for outages of critical facilities; and a determination as to whether there's sufficient available transmission capability on a regional constrained party, none of which have been provided for the record or review of the PSC staff, parties, or Commission. Plante, Tr. 3729-32. Without these electrical performance modeling and studies, there is no basis for a Commission determination about whether the project provides reliability benefits.

No reliability studies have been completed by any party on the Arrowhead line as a stand-alone project, and instead applicants rest their application on the prior work of WIREs and WRAO's 3j. Borgard, Tr. at 3371, 3372; Plante, Tr. at 3722-7; Leovy, Tr. at 6184. Because of the distinction between Arrowhead and Plan 3j, as above, the WIREs and WRAO reports do not provide an engineering basis for reliability claims of the applicants.

Applicants must submit an engineering plan "at least 60 days prior to the filing of an application for a certificate of public convenience and necessity." Wisc. Stat. §196.491(3)3a. This plan must show:

[T]he location of the facility, a description of the facility, including the major components of the facility that have a significant air, water or solid waste pollution potential, and a description of the anticipated effects of the facility on air and water quality.

Id. Siebert of the DNR testified that, "No, we did not receive an engineering plan." Siebert, Tr. at 5835. A letter from Siebert dated June 2, 2000, explained that "cumulatively the information provided by the applicant constituted sufficient information to fulfill the requirements of Section 196.491(3)(a), Wisconsin Stats., relative to an engineering plan." Id., Tr. at 5827 (emphasis added). Whether the "cumulative information" was provided 60 days prior to filing was not addressed on the record – it implicitly was not provided in the form of an "engineering plan."

Applicants have not produced sufficient engineering information to provide a basis for a Commission determination in favor of the applicants under Wisc. Stat. §196.491(3)(d)3. If the applicants want approval for this project, the record must be reopened and the applicants must submit the requisite electrical performance

studies and modeling upon which the Commission can base a decision.

**B. THE ARROWHEAD LINE IS NOT IN THE PUBLIC INTEREST BECAUSE IT DOES NOT PROVIDE ECONOMIC BENEFITS SUFFICIENT TO JUSTIFY THE LINE**

**1. Individuals will suffer the hardships of condemnation through eminent domain.**

The Arrowhead project does not have a sufficiently public purpose to support use of eminent domain. Nevertheless, if eminent domain is used to condemn land, any party wishing to contest either use of eminent domain or the valuation of their individual parcel must take part in the proceeding and assume financial responsibility for that challenge. But even if a party does challenge eminent domain after issuance of a CPCN, the condemnation may proceed. Wisc. Stat. §32.05(5).

individuals will receive compensation based upon a valuation two years prior to issuance of a CPCN, which by definition decreases the value of their property and which effectively results in a significant discount for utilities using eminent domain rather than pay market rate. Wisc. Stat. § 32.07. Landowners along the route will also suffer hardships from the decrease of valuation attributable to fear and public perception of the impact of the line on the property and any inhabitants. See **Economics**, below.

**2. Property values will decline and harm the local economy.**

Property values will drop if the Arrowhead-Weston line is constructed. In studies cited by WPS' witness:

Property owners reported they knew of the HVTL (79.9%) before buying their home, the HVTL had no effect on the price paid or the buying decision (76.3%), and they would buy in the same location again (79.9%). In contrast, the majority of appraisers (50-70.5%), builders (70.3%), realtors (82.5-87.1%) and

lenders (50-63%) reported believing that a tower(sic) line right of way had a negative impact on value.

Karvel, Dir. p. 4, Tr. at 7511. Karvel then cites to another such example:

This conclusion is supported by a survey of real estate appraisers (Delaney & Timmons, 1992). Real estate appraisers were divided into two groups: one was appraisers with experience valuing residences in proximity to HVTL's, the other group had not appraised such property. Appraisers with prior HVTL valuation experience were reported as estimating an average residential value decrease of 10.01%, while those without any experience estimated the decrease in value to be 11.94%.

Karvel, Id. He testified that:

Yeah, I think the majority of appraisers, builders, realtors and lenders reported believing that a tower(sic) line right-of-way had a negative impact on value and market contrast to the opinions of the market.

Karvel, Tr. at 7606. And those with experience would expect at least a 10% decrease.

Id. SOUL's witness agreed with this approximation. Messner, Tr. at 7740.

There was no consideration of the impact of the powerline on businesses in the area. Karvel, Tr. at 7564. There was also no consideration of timber land that was not commercial, but was instead private forest, or forest preserve. Messner, Dir. p. 4, Tr. at 7673. Conversely, Karvel cites to a Duluth newspaper article as proof that property values are rising "dramatically" but when asked whether this is the type of literature that experts in his field rely on, he then testifies:

Let's put it this way, it is what it is and it speaks for itself but no, I hardly consider newspapers unless it's my column to be an authoritative source of information.

Karvel, Tr. at 7561. When asked to define "dramatically," he quantified it as 8-10 percent. Karvel, Tr. at 7588.

Karvel defines a "significant" loss as "losses beyond compensation for the

right-of-way itself. Karvel, Tr. at 7502. He testifies that powerlines are “certainly potential sources of loss.” Karvel, Tr. at 7578.

Fear and perception of danger, whether real or imagined, has been established as a legal basis for compensation to a landowner subject to a partial taking for an easement where the remainder of the land has diminished in value due to the easement, or more correctly, the use that easement is put to. In such cases, the majority of jurisdictions hold, there is no requirement that the fear be justified, and that appraisal testimony regarding diminution in property value based upon perception and fear of health consequences, “any competent evidence,” shall be admitted. See San Diego Gas & Elec. Co. v. Daley, 253 Cal. Rptr. 144 (Cal. Ct. App. 1988). WPS’ witness Karvel testified about this:

Q: Are you aware of the impact – the potential impact of cancerphobia on property values?

A: There’s been some reports that would indicate that there is some reaction to that, yes. I don’t know that we have any clear answers as to how that is impacting the marketplace at this juncture.

Q: Are you aware if it has had legal impacts on property valuation?

A: I recall one case in which the Court said that it wasn’t necessary to prove that EMF has – whether EMF caused cancer or not. All that was required was the property owner to show that the property value was diminished, an opinion with which I might say I concur.

Karvel, Tr. at 7612

Despite all his testimony about valuation, not one appraisal was completed and Karvel is not a licensed appraiser. Karvel, Tr. at 7556, 7594. He explained that an easement valuation is done by completing a before and after measure of valuation, sometimes referred to as a diminution appraisal, yet even with this method to

determine accurately the impact of the line, he submitted no such appraisal. Karvel, Tr. at 7594.

Karvel knew little about this proceeding or the project proposed. He had not read the Application and only knew about the issue what he had been told. Id., Tr. at 7572. He encouraged shared corridors, but did not have any idea the percentage of the line route that facilitated such sharing. Id. Karvel did not do a bibliographic search, and what information he did rely on was old, such as studies from 1972, 1964 and another in the '50's. Karvel, 7576, 7572-5. He had done no research on whether the announcement of the powerline had any impact on values, and had not reviewed any research on the matter, and had not talked to anyone in the area. Karvel, Tr. at 7592. WPS' witness did not complete a paired sale analysis or a multiple regression analysis for the record. Karvel, Tr. at 7600.

Real estate experts agree -- property values in the area of the Arrowhead powerline will decrease significantly.

**3. The public will not be the economic benefactor of the line.**

Applicants and supporters claim that the Arrowhead-Weston line will provide economic benefits in the form of greater availability of more inexpensive power, but as above, the public, whether citizens or ratepayers, will not be the economic benefactor of the Arrowhead line. Not only will the utilities and not the consumers and the public be the benefactors of the line, but given the nature of market economics, where supply flows to the highest bidder, it is also unlikely that the WUMS utilities will receive any economic benefit. Utility claims of economic benefits are illusory at best in a market economy as demonstrated by a supporting Intervenor's understanding of basic

market concepts generally, but who is not able to apply it to this specific case:

Q: Now, hypothetically can you imagine a world where there is free market wholesale competition and no transmission constraints?

A: Can I imagine that?

Q: Yes, can you imagine that?

A: Yes, I can.

Q: Now, if that exists, doesn't that mean that the electricity will be sold to the highest bidder?

A: Absent market dislocations, generally, yes, the highest bidder is the one who purchases.

Q: Okay. And then for a hypothetical, let's assume that rates in Illinois are higher than that in Wisconsin, the economical western and Canadian electricity would then be sold to Illinois and not Wisconsin, wouldn't it?

A:... I think in the short-term. I don't know that the market will allow that to exist over the long-term. But in a micro situation, that's not incorrect.

Q: And in that case, if rates are higher elsewhere than they are in Wisconsin, your constituents would not benefit from that power, correct?

A: Well, again, it appears as though you're talking about a single source of power.

Q: This is a hypothetical.

A: That I can't conceive of. There is a disconnect. I'm not understanding that concept. Full competition will get power to those who need it. There will be a way that that will be done. And prices will change elsewhere also.

Gustafson, Tr. at 5205; see also 5212. Another supporting Intervenor was as unable to address the flow of power to the highest bidder, a fact of competition:

Q: And if Wisconsin improves its transmission capability to the west, can you say for certain that that is going to increase the availability of transmission to MEUW members given that they will be competing with other entities to the south?

A: Answering that question, the primary concern of MEUW members and why

they support this line is for reliability purposes to make a redundant connection to the west so that we're not held hostage to a hail storm or a wind storm that takes out the only connection that we have to the west. **Purchases over that line would be secondary.**

Q: When was the last time a hail storm took out the only connection we have to the west, do you recall?

A: I mention that as an example. I don't know.

Q: Do you know if it has ever happened, a wind storm, a tornado?

A: California is having a heck of a problem –

Q: I'm sorry, I'm asking about our connection to the west.

A: I mentioned about transmission lines taken down by mother nature. California is having problems yesterday and today because of that.

Q: California also has problems because it doesn't have generation, is that correct?

A: That is correct. Benforado, Tr. at 4783-4.

The fact of a powerline on real property can have an impact on willingness of lenders to finance a purchase, refinance, or construction loan:

Q: ...would it surprise you to apply for let's say a loan to buy a farm in the area and bankers being concerned about stray voltage?

A: Yes. Bankers are very concerned.

Dahlberg, Tr. at 8889.

#### **4. Fiber optic revenue will flow to the applicants**

Fiber optic revenue, which could be significant, has not been adequately addressed in this proceeding. Applicants first included fiber optic in their application, and then wanted to withdraw the fiber optic aspect of the application, but when questioned, wanted to retain it as an option, and would not stipulate to dismissal of that aspect of the application. Valine, 6751-7660. By keeping the option to construct



and utilize fiber optic capability, but disowning it as part of the application, the applicants effectively limited disclosure of the economic benefits of fiber optic, and prevented Exhibits from being entered into the record because no witnesses were able to testify about it. Valine, Tr. at 6863. The revenue of any fiber optic venture will, under a contractual arrangement, go to the original applicant utilities. Landgren, Tr. at 4493.

The economic potential of fiber optic must be disclosed and addressed.

**5. The economic impact of transfer of assets to ATC is unclear.**

ATC was formed through an act of the legislature, and it is planned that ATC shall be the ultimate owner and operator of the Arrowhead line. Because the hearings for this line were in progress, by contractual arrangements, ATC will not take possession until after the construction of the line is finished. Borgard, 3229-3230. These assets are to be transferred to ATC at **net book value** upon completion of the project. Id. If that occurs, WPS stake in ATC will increase four-fold. Id.

The impact of the appointment former Governor Earl as an AATC “independent” Director has not been addressed. Issues that should be considered are investigation and disclosure of campaign contributions of any parties to this proceeding and discovery and disclosure of any potential conflicts of interest or relationships with Applicants and/or other parties.

ATC is now requesting to change its status in this proceeding from that of a party to that of an applicant. This matter is being addresses separately as a Motion, and has yet to be determined by the PSC. There is also a constitutional challenge to the manner in which ATC was formed, brought to the Attorney General of the state,

and those same issues have been raised in the Motion pending before the PSC on ATC's status.

**IV. THE HEALTH AND SAFETY CONCERNS ABOUT THE ARROWHEAD PROJECT OUTWEIGH ANY RELIABILITY AND ECONOMIC BENEFIT THAT THE LINE MAY PROVIDE.**

In other dockets the Commission has addressed, to some extent, the health and safety concerns surrounding transmission and distribution of electricity, and the Commission is charged with protection of the health and safety of the citizens of the state of Wisconsin. The Commission must now address the health and safety concerns associated with the electrical effects of the Arrowhead powerline. Wisc. Stat. §196.491(4). Rules of evidence are more relaxed in an administrative hearing a “review of the case law in Wisconsin vis-a-vie expert opinions is that a probability is enough, that 51 percent is reasonable scientific probability and reasonable scientific certainty have been interpreted to mean the same thing which means a little over 51 percent...” and in addition, Daubert is not controlling, “we don’t apply Daubert in this. This is an administrative proceeding on top of it which means relaxed rules.” Judge Geske, Tr. at 8842. There is no basis for a determination by the Commission that this line is safe or that will not damage the health of the people and animals nearby.

The most important issue of health and safety presented by the Arrowhead line is that of Electromagnetic Fields, commonly known as EMF. Evidence<sup>26</sup> has been

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<sup>26</sup> For an administrative hearing, a “review of the case law in Wisconsin vis-a-vie expert opinions is that a probability is enough, that 51 percent is reasonable scientific probability and reasonable scientific certainty have been interpreted to mean the same thing which means a little over 51 percent...” and in addition, Daubert is not

entered in the record that shows that electric fields are expected to be above that allowed in the state of Minnesota. Wisconsin has no such limitations on electric fields. Magnetic fields are expected to be much, much higher at the edge of the right of way than the level that has shown an association with increased rates of cancer in humans. The powerline also emits corona, which ionizes particulate matter, such as vehicle exhaust, and which is then subject to increased deposition externally on skin and internally in the lungs through inhalation. These issues raise serious health and safety questions that overshadow any reliability or economic benefit to the public.

**A. EMF, A PHENOMENON ASSOCIATED WITH HIGH VOLTAGE TRANSMISSION LINES, IS EXPECTED TO BE 10 TO 15 TIMES GREATER AT THE EDGE OF THE RIGHT OF WAY THAN THE LEVEL FOUND ASSOCIATED WITH INCREASED RISK OF LEUKEMIA**

Peak magnetic fields on the right-of-way will be between 135 and 248 mG, depending on the configuration of the line and the presence of parallel lines. The peak fields are computed for conductors carrying 80% of normal peak load and at their minimum height above ground... The magnetic field at the edge of the right-of-way ranges between about 40 and 60 mG, depending on the line configuration and other lines in the corridor.

Bracken, Dir. p. 10-11, Tr. at 9504-5(emphasis added)

**For the very small population (0.8%) of subjects with exposure above 4 mG, the data show a two-fold increase.**

Ex. 332, DAD 19, Ahlbom, et al., A pooled analysis of magnetic fields and

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controlling, “we don’t apply Daubert in this. This is an administrative proceeding on top of it which means relaxed rules.” Judge Geske, Tr. at 8842.

childhood leukaemia, British Jour. of Cancer, 83(5) 692-698 (2000).

**While the support from individual studies is weak, the epidemiological studies demonstrate, for some methods of measuring exposure, a fairly consistent pattern of a small, increased risk with increasing exposure that is somewhat weaker for chronic lymphocytic leukemia than for childhood leukemia...**

**...The NIEHS agrees that the associations reported for childhood leukemia and adult chronic lymphocytic leukemia cannot be dismissed easily as random or negative findings.**

**EMF-RAPID (selected), National Institutes of Health and Environmental Health Sciences (1999).**

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The Commission must determine that “[t]he proposed facility will not have undue adverse impact on ... public health and welfare...” Wisc. Stat. §196.491(4). There is no basis, however, for a finding by the Commission that EMF does not have an undue adverse impact on public health and welfare, that EMF does not endanger the public, that EMF is safe, and that EMF does not cause health problems, and that EMF does not induce cancer. Even Dr. Moulder, the applicants’ lead EMF witness in both Minnesota and Wisconsin, agrees with his previous testimony in the Minnesota Arrowhead and Chisago proceedings that EMF may cause health problems, that EMF cannot be proven safe, and that exposure to EMF may induce cancers. Moulder, Tr. at 9432, 9433, 9437. When asked whether there were “no health risks from human exposure” and whether “emerging evidence no longer allows one to categorically assert there are no risks,” he responded, “I don’t think you can ever categorically assert that there were no risks. You certainly couldn’t categorically assert that in 1989.” Moulder, Tr. at 9469-70.

EMF is a complicated topic, deemed worthy of a 26 page appendix in the FEIS.

In the FEIS, EMF is explained:

Electricity produces two types of fields; an electric field and a magnetic field. These fields are called electromagnetic fields or EMF...

Power line magnetic fields are in the Extremely Low Frequency (ELF) range of the electromagnetic spectrum... Cells can respond to exposure to these low energy fields...

Magnetic fields are created by charges (electrons) moving in a conductor, such as a wire. The number of electrons moving through a conductor at any given time is called the current (measured in amperes). As the current increases, so does the magnetic field. The magnetic field decreases as the distance from the source increases.

Electric fields are found wherever there is electricity. Electric fields are created by the presence of electric charges and measured in volts per meter (Vm). An electric field is associated with any device or wire that is connected to a source of electricity, even when a current is not flowing.

The size of the magnetic field cannot be predicted from the voltage. It is not uncommon for a 69 kV line to have a higher magnetic field than a 115 kV line. This is because the current flowing in the line, not the voltage, creates the magnetic field. The size of the magnetic field around a line is proportional to the current. This means that the magnetic field level increases as the current in the line increases. Very high voltage lines (345 kV) generally carry high current and as a result produce relatively high magnetic fields.

Ex. 172, FEIS, Appendix D, p. 1-3.

EMF research began nearly 30 years ago, and there have been hundreds of studies of subjects who included electrical workers, adults and children using appliances, and adults and children living near powerlines.<sup>27</sup> See Ex. 345, Electrical and Biological Effects of Transmission Lines: A Review, Chapter 3, Lee, Bonneville

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<sup>27</sup> Research on electromagnetic fields is very difficult, in a large part due to the many variables that could have an impact on the findings, and in part because of the difficulty of locating control groups not affected by electricity. Dahlberg, Tr. at 8870-72; 8878.

Power Administration (1996); see also Ex. 343, DAD-31, Electromagnetic Fields and the Life Environment, Marha, et al., Institute of Industrial Hygiene and Occupational Diseases, Prague, Czechoslovakia (1971); Ex. 351, DAD-48, Handbook of Biological Effects of Electromagnetic Fields (selected), eds. Polk & Postow, CRC Press (1996). W.R. Adey was a pioneer in this area, authoring a study addressing the “physical processes underlying biological interactions with natural and artificial electromagnetic fields.” Ex. 340, DAD-29, Adey, Tissue Interactions with Nonionizing Electromagnetic Fields, 61 Physiological Reviews 2, 435, 436 (1961). Moulder admitted that Adey’s work showed a relationship on a molecular level of the interaction of electric fields with the polarity of molecules and cell membrane. Tr. at 9460; see also Tr. at 8757. Cellular studies have continued, and scientists are working to determine the specific causation mechanism:

Q:... don’t you think it shows a relationship on molecular level of electric fields interacting with polarity of the molecules and membrane?

A: It shows that strong electrical fields can affect the cell membrane, yes.

Moulder, Tr. at 9470; see Chen, In these studies, Moulder agrees that:

The strength of the association is not dependent on an ascending gradient dose relationship.

Tr. at 9470. Moulder again admitted, citing Chen’s studies, that studies have shown that electrical exposure can change cells:

That study is working in cell culture with a type of leukemia cell and they show that exposure to I think it was 60 hertz fields cause change in the cells that resembled the changes produced by chemical carcinogens.

Moulder, Tr. at 9439.

The Bonneville summary of the state of research at that time, although now dated because of the many studies released since that date, was predictive:

Research summarized in this chapter suggests that EMF may be a risk factor for leukemia, brain cancer, or possibly other cancers. Meta-analyses of this research find statistically significant increased risks of about 1.20-2.00.

Ex. 345, DAD-35, Bonneville Report, p. D-5.

Magnetic fields are measured in Gauss, and because levels are often far less than a Gauss, magnetic field measurements are typically expressed in milligauss, one-thousandth of a gauss.

Id. The Arrowhead line's estimated electric and magnetic currents have been estimated by the applicants. Ex. 171, Vol. 1, Figure A26-1 through A26-22, Arrowhead to Weston, Calculated Magnetic Field Data.

Peak magnetic fields on the right-of-way will be between 135 and 248 mG, depending on the configuration of the line and the presence of parallel lines. The peak fields are computed for conductors carrying 80% of normal peak load and at their minimum height above ground... The magnetic field at the edge of the right-of-way ranges between about 40 and 60 mG, depending on the line configuration and other lines in the corridor.

Id., Bracken, Dir. p. 10-11, Tr. at 9504-5(emphasis added).

Dr. Dahlberg, witness for W.O.L.F., refers to electrical phenomenon as EM energy as a generic term to refer to any and all electric and magnetic energies, which can adversely affect the behavior, health and production of confined livestock and the health of people." Dahlberg, Dir. p. 3, Tr. at 8742. Dr. Dahlberg cites five categories of EM energy:

First is the well-known effect commonly referred to as electrocution. Electrocution occurs when a large, usually short duration electric current passes through a living organism, often causing immediate death. The second category is the perceived effects from exposure to 50 and 60 Hz

electricity, primarily from the 50 and 60 Hz magnetic fields. Of particular significance is the proximity of affected people to transmission and distribution lines. Third is the perceived effects associated with micro- and radio-wave EM energies from radar systems, microwave transmission, radio and television transmission, and cellular systems. The fourth category, called stray voltage, has been associated with effects on both humans and dairy animals, primarily within the confines of the dairy barn. The actual EM energy associated with stray voltage effects may include exposures to currents as well as to electric and/or magnetic fields. The fifth category is associated with the DC transmission lines used in a few areas of the world. Living and working in proximity to these lines has been perceived by many as causing an number of health problems.

Dahlberg, Dir. at 5-6, Tr. at 8744-5.

Applicants' witness, Moulder, prefers to use the term "power-frequency" which:

...refers to the alternating current (AC) frequencies used in electric power systems, and the term "power-frequency field" refers to the sinusoidal electric and magnetic fields produced by power lines and electric devices. The phrase "EMF" is an imprecise term that could apply to many different types of fields, and the term has a long-standing use in physics to refer to an entirely different concept, electromotive force.

Moulder, Ex. 378, Power-Frequency Fields and Human Health: Summary of Research, 1995-2000, p. 2.

EMF can also introduce currents from transmission lines into the earth:

Magnetic fields from overhead transmission lines cause 60-Hz voltage gradients in the earth along the length of the line through magnetic induction. These voltage gradients can lead to current flow in the earth, or through conductors that contact the earth at more than one point. For example, induced currents can flow in the earth from grounded overhead lightening protection wires, parallel fences, and parallel pipelines.

Ex. 380, An Assessment of Health Effects of the Electrical Environment on Dairy Farms, Erdreich and Bracken, August 13, 1993, p. 23. Bracken repeatedly admits earth currents are induced by powerlines. Bracken, August 13, 1993, p. iii, 15 (Tr. at 9354), 16 (Tr. at 9364), 17, 18, 20, 21 (Tr. at 9364), 22 (Tr. at 9364), 23, 24; see also



Bracken, Tr. at 9547-8, 9549; but c.f. Schott, Tr. at 9357, 9359, 9363.

Dr. Dahlberg testified about several ways that ground currents get in the earth:

One is if there's an imbalance between the currents in the three phases of the line, that means the current has to be in the neutral. There is no neutral wire in this transmission line so all that current has to go through the ground. That's one way.

Another way is that there's a magnetic field associated with the line. That magnetic field induces current in all conductors including the earth. The earth is a conductor. And it induces currents for some distances from the line.

There's also an electric field associated with the line which induces current into the ground. In addition, there's leakage across the insulators and the -- every tower is ground and that wire goes into the ground.

There's also a wire -- a protection wire that runs over the transmission lines. There's going to be current induced in that and that's connected to the grounding system. And so that also was able to introduce current in the ground.

Dahlberg, Tr. at 8088-9; see also Ex. 380, An Assessment of Health Effects of the Electrical Environment on Dairy Farms, Erdreich. Earth currents are a continual problem. Dahlberg, Tr. at 8877. Fifty-nine percent of electricity returns through the earth instead of on the wires.<sup>28</sup> Dahlberg, Tr. at 8881.

Health concerns related to EMF abound:

The concern about environmental power-frequency fields is largely restricted to cancer, although some public and scientific attention has also been devoted to other possible health hazards including miscarriages, birth defects, cardiovascular disease, and allergic reactions.

Moulder, Ex. 378, Power-Frequency Fields and Human Health: Summary of Research,

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<sup>28</sup> How the current travels in the earth is at issue. Bracken testifies that earth currents travel deep in the earth, but then admits "power quality problems with high frequency harmonics and transients" "is an issue for certain users of electricity," and that harmonics and transients have a skin effect of wanting to ride on the surface. Tr. at 9553-4.

1995-2000, p. 2. The Bonneville Power review, a utility sponsored compilation, was more direct:

Research summarized in this chapter suggests that EMF may be a risk factor for leukemia, brain cancer, or possibly other cancers.

Ex. 345, Electrical and Biological Effects of Transmission Lines, Bonneville Power(1996).

The language and methodology of epidemiology research is one of statistics, where studies are reviewed for statistical significance and the results are expressed in defined “codes.” Epidemiological studies address relative risk:

An RR/OR of 1.0 means no difference between exposed and unexposed populations. An RR/OR less than one means the exposed population is at lower risk than the unexposed population while an RR greater than one indicates an increased risk. An RR/OR of 1.5 would suggest the exposed population is 50 percent more likely to contract a disease than the unexposed population... An RR of less than 3 is usually considered weak. Relative risk values of 1.5 or less are generally considered too weak to support any meaningful conclusions....

An RR of 5 or more is generally considered strong... An RR of less than 3 is usually considered weak...

Because the results of a study are statistical estimates, researchers must present a range over which they are confident the estimate is reliable and the result is less likely to be caused by a random statistical variation. This is usually expressed as a 95 percent confidence interval. For example, a reported RR of 1.2 with a 95 percent confidence interval of 0.7-2.9 (reported as RR 1.2 (0.7-1.9) means that the researcher is 95 percent confident that the true value for the RR is between 0.7 and 1.9.

Ex. 172, FEIS, Appendix D, p. D-6, D-7.

Since the Bonneville report, much research has been completed that examines the relationship of EMF and cancer, non-cancer health studies and other diseases which

shows, by a utility report's admission, "that EMF may be a risk factor for leukemia, brain cancer, or possibly other cancers. Ex. 345, Bonneville Report, p. 2-31-2-37, 3-35-3-43(1996 compilation of research to date). One of the first studies to show an association between EMF and risk of childhood cancer was the "Wertheimer and Leeper" study, which found increased cancer mortality in children living near high-voltage transmission lines, and attributed the findings to magnetic fields in the 2-3 mG range. Id., p. 3-5, 3-43 (citing Wertheimer N., Leeper E., Electrical wiring configurations and childhood cancer, 109 Amer. J. of Epid. 273 (1979).

Wertheimer has continued her work, and in 1995, published another study that looked at the health effects of ground/earth currents emanating from electric transmission lines. Ex. 327, DAD-11, Wertheimer, Savits & Leeper, Childhood Cancer in Relation to Indicators of Magnetic Fields from Ground Current Sources, 16 Bioelectromagnetics 86 (1995); see also Ex. 380, An Assessment of Health Effects of the Electrical Environment on Dairy Farms, Erdreich and Bracken, August 13, 1993, p. iii, 15, 16, 17, 20, 23, 24(admits currents in the earth from electrical transmission systems); see also Bracken, Tr. at 9354, 9355, 9364. Dahlberg and Bracken are in agreement that earth currents exist and that their source is electrical lines, and that earth currents are a problem. Dalhberg, Tr. at 8807-8813; Ex. 380, An Assessment of Health Effects of the Electrical Environment on Dairy Farms, Erdreich and Bracken, August 13, 1993, p. iii, 15, 16, 17, 20, 23, 24(admits currents in the earth from electrical transmission systems); see also Bracken, Tr. at 9354, 9355, 9364.

Wertheimer's study reported:

An increased cancer risk was observed for children in homes with conductive

plumbing: The matched odds ratio was 1.72 (1.03-2.88) and increased to 3.00 (1.33-6.76) when analysis was limited to cases and controls who were residentially stable from the reference date to the study date... In contrast to measured field intensity alone, for which only modest associations with cancer have been reported, this metric shows a high and significant cancer risk [matched O.R. = 4.0 (1.6-10.0)] consistent over a range of intensity and angle cutpoints. Such elevated nonvertical fields were also associated with cancer in an independent data set, which was gathered to study adult nonlymphocytic leukemia in the Seattle area. The associations of cancer with conductive plumbing and with this exposure metric both suggest that cancer risk is increased among persons with elevated magnetic field exposure from residential ground currents.

Id., p. 86. Despite these findings, Schott, WPS electrical engineer, testified that WPS was not required by the PSC to test for earth currents, therefore they did not. Schott, Tr. at 9359. Schott also testified that he is not aware of any long-term continuous research studies on animals that have been done on the stray voltage which results from earth currents and therefore the health effects would be unknown. Schott, Tr. at 9354, 9355; Dahlberg, Tr. at 8805-6; Ex. 380, Bracken, p. 20 (ground currents from the transmission systems are recognized as potential for stray voltage). However, Dr. Peterson specifically set forth the serious health effects and problems that she found in animals that were in proximity to or associated with ground currents. See also Ex. 325, Hartsell, et al. (1994); Ex. 326, Marles, et al. (1995); Ex. 335, Hillman, et al.

Health concerns were also raised in the findings of a Draft Report prepared for the Environmental Protection Agency, which found that:

A large number of human studies are available in which the relationship between human cancer incidence or mortality and exposure to EM fields has been investigated. From these studies the strongest relative evidence that exposure to EM fields is causally related to human cancer comes from case-control studies of cancer in children. Seven of these have examined residential exposure from electric power transmission and distribution lines and two others have examined cancer in children in relation to father's occupation. These studies have consistently found modestly elevated risks (some

statistically significant) of leukemia, cancer of the nervous system and, to a lesser extent, lymphomas. These findings are associated with magnetic fields in homes where children reside which were estimated after the diagnosis with both magnetic field measurements and with surrogate indicators of magnetic fields, i.e., wiring codes. Electric fields were not found to be a critical factor thus far. In two studies in which magnetic fields measurements were made, significant elevated risks were observed in those exposed at or above 2 to 3 milligauss (mG). In contrast with adults, children probably have relatively few confounding factors other than EM fields that could explain the association because of their shorter lifespan and lack of occupational exposure. In fact, potential confounders and biases that might have affected the results were examined by one of the authors in some detail and found not to explain the results. As yet, no other agents have been identified that could explain this association.

Ex. 329, DAD-14, Evaluation of the Potential Carcinogenicity of Electromagnetic Fields, p. 1-2, (attached to Long-Suppressed Draft EPA Report: EMF's Present a Cancer Risk, Microwave News) Environmental Protection Agency Docket: EPA/600/6-90 (1990). This report has been suppressed by the EPA, which will not even release it in response to Freedom of Information Act requests. Ex. 329, DAD-14, Microwave News, January/February, 1998.<sup>29</sup>

The threshold for significant elevated risks cited above is 2-3 milligauss.

Again, the Bonneville report is dated, and recently released research advances documentation of the association of EMF and cancer:

For the 3203 children with leukaemia and 10,338 control children with estimate residential magnetic field exposures levels  $<0.4\text{T}$  [4 mG], we observed risk estimates near the no effect level, while for the 44 children with leukaemia and 62 control children with estimated residential magnetic field exposures  $\geq 0.4\text{T}$  [4 mG] the estimated summary relative risk was 2.00 (1.27-3.13, P value = 0.002). Adjustment for potential confounding variables did not appreciably change the results. For North American subjects whose residents were in the highest wire code category, the estimated summary relative risk was 1.24 (0.82-187). Thus,

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<sup>29</sup> Another emerging issue is electric sensitivity. Ex. 345, Bonneville, Ch. 2; see also Dahlberg, p. 8855-7.

we found no evidence in the combined data for the existence of the so-called wire-code paradox. In summary, the 99.2% of children residing in homes with exposure levels  $<0.4 \text{ } \mu\text{T}$  [mG] had estimates compatible with no increased risk, while the 0.08% of children with exposures  $\geq 0.4 \text{ } \mu\text{T}$  [4 mG] had a relative risk estimate of approximately 2, which is unlikely to be due to random variability...

...Across the measurement studies, the summary relative risk is estimated at 1.87 (95% CI: 1/10-3.18) in the highest exposure category, with a corresponding P value of 0.01. The two lower categories have estimates close to unity. For the calculated fields studies the summary measure for the top exposure category is 2.13 (0.93-4.88), with a P value of 0.004.

Ex. 332, DAD-19, A pooled analysis of magnetic fields and childhood leukaemia, Ahlbom, et al., 83(5) Br. J. Cancer 692 (1999)(mG equivalents added)(see above for explanation of numerical study results);see also Dahlberg, Tr. at 8880-8881. Authors of this study were Ahlbom, Day, Feychting, Roman, Skinner, Dockerty, Linet, McBride, Michaelis, Olsen, Tynes and Verkasalo. Here, the threshold cited for significant elevated risks was 4 milligauss. Of the authors of the "Pooled analysis" study, Ahlbom, Day, Linet and McBride have all previously published studies showing no significant association and cited by WPS' Moulder. This study refutes their previous work showing no significant association. See e.g., Ex. 287, Moulder, Power-Frequency Fields and Human Health: 1995-2000, p. 39 (Linet, McBride); Ex. 345, Bonneville, p. 3-37-3-45. Even Moulder admits that the confidence interval of the pooled Ahlbom study is 95%, sufficient for scientific certainty. Moulder, Tr. at 9432.

The Microwave News report summarized the pooled study:

A pooled analysis of raw data from nine different electromagnetic field (EMF) studies has found that children exposed to 4 mG or more were twice as likely to develop leukemia.

Ex. 362, DAD 53, Leading Epidemiologists See Childhood Leukemia Risk at 4 mG, Microwave News, September 2000. Microwave News reports that these findings are

similar to those of Greenland, who said, “The main point is, you don’t see anything until you get into the higher categories.” Id. “The Ahlbom and Greenland papers reflect a growing consensus on the apparent association between magnetic fields and childhood leukemia.” Id. As summarized by Dr. Dahlberg:

An extensive body of information resulting from both quantitative and qualitative research delineates health effects from exposure to power frequency magnetic and electric fields, radio and microwave frequency radiation, and electric currents including both alternating and direct currents...From my many years of studying the research literature, from my research, and my investigating health problems associated with sources of EM energies, I have concluded that EM energies can adversely affect the behavior, health, and production of confined livestock and the health of people...The action in this proposed docket will increase the electrical exposure for many people and many other living organisms...The people of Wisconsin deserve a fair appraisal of potential effects even if all of the scientists are not certain of these effects...

Dahlberg, Dir. p. 17-18, 19, Tr. at 8756-7, 8759.

The threshold levels for concern found in these studies, where increased risk of leukemia is associated with EMF, is 4 mG, which shows a significant increase in risk. When that level is compared against the levels expected for the edge of the right of way of the Arrowhead line, the expected levels are far above those with increased risk of cancer:

Peak magnetic fields on the right-of-way will be between 135 and 248 mG ...The magnetic field at the edge of the right-of-way ranges between about 40 and 60 mG, depending on the line configuration and other lines in the corridor.

Bracken, Dir. p. 10-11, Tr. at 9504-5 (emphasis added). The 135 to 248 levels in the right of way are between 33.75 and 62 times the 4 mG level threshold for increased risk of cancer, and the 40-60 mG levels at the edge of the right of way are between 10 and 15 times the 4 mG level shown to increase risk of cancer.

The EMF-RAPID study, based upon its extensive review of research, focusing on 2 mG levels, half that of the 4 mG level of increased risk, recommended a preventative approach, verified by Moulder:

Q:...Isn't it correct that the EMF-RAPID report states that NIEHS suggests that the power industry continue its current practice of siting powerlines to reduce exposures and continue to explore ways to reduce the creation of magnetic fields around transmission and distribution lines without creating new hazards?...

A:... I recall words to that effect, yes.

Moulder, Tr. at 9428-9. When asked if he agreed that EMF-RAPID's childhood leukemia and adult lymphocytic leukemia findings cannot be easily dismissed as random or negative findings, he testified that "I would agree that there are some weak associations have been shown and therefore, they cannot be dismissed." Moulder, Tr. at 9455-6.

The preventative approach recommended by EMF-RAPID is similar to the Precautionary Principle advocated by Dr. Dahlberg:

When an activity raises threats of harm to human health or the environment, precautionary measures should be taken even if some cause-and-effect relationships are not fully established scientifically.

Dahlberg, Dir. p. 20, Tr. at 8759. When asked whether "the only way to eliminate EM energies was to just stop using electricity," Dalhberg testified that "...you'll always have electrical magnetic energy but you can reduce it and if you want to make some changes in the system, it could be reduced to the point where it's tolerable. Dahlberg, Tr. at 8846. "Tolerable," according to Dahlberg, is near the threshold reported by the studies, "the number that's being used is somewhere between three and four milligauss." Id.



But despite proof that the levels at the edge of the right of way, Moulder testified that he was familiar with the estimated “power frequency fields” associated with the project, but he was not familiar with the route of the line, could not identify it on a map, and was unable to identify the areas or the homes that would receive the greatest exposure levels of EMF. Although he was ostensibly testifying that the line posed no danger to the public, as in Minnesota, Dr. Moulder testified that he was not familiar with the project proposal or the line route:

Q: Can you point out the areas along that route where you would expect people to receive or do you expect to find the greatest exposure to EMF levels?

A: No, I can't because that would depend on knowing exactly which part of the line has 340 .. 345 kV and I don't remember that offhand. You would also have to know how close people live to the line in various areas and that I do not know.

Q: Have you reviewed the application?

A: Yes, I have.

Q: Have you reviewed the table that lists houses and the distances from houses to the line?

A: I think I did four or five months ago, yes.

Q: And --

A: At the time I wrote the report.

Q: And you don't recall how far away those houses are?

A: No, I don't....To relate that to a specific dwelling you would need an estimate of what the field would be at that dwelling.

Moulder, Tr. at 9429-30; see also Ex. 171, Vol. 1, Figure A26-1 through A26-22, Arrowhead to Weston, Calculated Magnetic Field Data. No such estimates of the field levels at homes closest to the route were submitted for the record by applicants, and

there is no basis in the record for a finding that EMF will not effect local residents.

The EMF-RAPID workgroup identified EMF as a Class 2B Carcinogen, which means that it is “probably carcinogenic for humans,” in the same category as beryllium, carbon tetrachloride, and polychlorinated biphenyls (PCBs). Ex. 343, EMF-RAPID, final page of exhibit; Dahlberg, p. 8851-2, 8862-7. Dahlberg agrees that there “are an awful lot of every day substances and activities that are within category 2B...that we should not be exposed to, yes.” Dahlberg, Tr. at 8865. Dr. Moulder discounted the importance of a 2B classification for lack of causation, but when asked to name class 2B carcinogens where there has been a causation mechanism demonstrated, he responded:

I’m not aware of any class 2B carcinogens where causation has been demonstrated almost by definition...

Moulder, Tr. at 9326. None of the accepted IARC Class 1, 2A or 2B carcinogens have met the “95%” scientific certainty standard. See e.g., Dahlberg, Tr. at 8869; 8879; see also Tr. at 9422, 9426, 9428. To wait until such proof is obtained, or delay action while assembling proof, such as with lead or asbestos, would put the population at risk. Dahlberg, Tr. at 8759.

Moulder is not credible because he stresses that causation has not been proven, implying that the studies are not relevant until causation is proven, and then ultimately admits that proof of causation is not the role of epidemiological studies:

Q: Has any epidemiological study ever demonstrated causation?

A: I don’t think a single epidemiology study can ever demonstrate causation.

Moulder, Tr. at 9326. He has no choice but to admit the validity of the studies:

Q: An did you agree that childhood leukemia and adult lymphocytic leukemia

cannot be easily dismissed as random or negative findings?

A: I would agree that there are some weak associations have been shown and therefore, the cannot be dismissed.

Moulder, Tr. at 9455-6. He cannot ignore the data:

Q: What I was reading from continued to go on saying the human data are in the right species are tied to real life exposures and show some consistency that is difficult to ignore, however no consistent explanation other than exposure to ELF, EMF has been identified, do you agree with that?

A: Yes, that's a reasonable statement.

Moulder, Tr. at 9456. Moulder holds himself out as an expert, yet he is not familiar with crucial research including Konig, H.L. (1974), Bawin, S.M. (1976), Schumann, Kavet (2000), Zaffanella (2000) and the background paper by the U.S. Office of Technology Assessment for the U.S. Congress (1989). Moulder, Tr. at 9463-70.

The Commission has no basis for a finding that the EMF of the Arrowhead powerline will not have undue adverse impact on public health and welfare. The applicants have not met their burden of proof to show that the EMF of the powerline will not have an undue adverse impact o public health and welfare. There is no basis for a finding by the Commission that EMF does not have an undue adverse impact on public health and welfare, that EMF does not endanger the public, that EMF is safe, and that EMF does not cause health problems, and that EMF does not induce cancer. The scientific evidence is sufficient to trigger the Precautionary Principle and deny the permit for the Arrowhead project.

**B. EFFECTS OF CORONA POSE A RISK TO THOSE LIVING AND WORKING NEAR A HIGH-VOLTAGE POWERLINE**

The Commission has no basis for a finding that the particulate ionizing effects

of the corona of the Arrowhead powerline will not have undue adverse impact on public health and welfare.

Corona occurs in regions of high electric-field strength on conductors, insulators, and hardware when sufficient energy is imparted to cause ionization (partial breakdown) of the air...Foul weather, therefore, causes a significant increase in corona activity on AC lines and the audible noise and radio noise produced by it.<sup>30</sup>

Ex. 345, Bonneville, p. 5-1, 5-2.

The ionization effects of the corona also cause particles in the air to become ionized, which “in a variety of weather conditions under high-voltage powerlines excess deposition of pollutant aerosols occurs...” This is known as the “Henshaw Hypothesis.” Ex. 333, DAD-20, Corona ions from powerlines and increased exposure to pollutant aerosols, Fews, Henshaw, et al., 75 Int. J. Radiat. Biol. 12, p. 1523 (1999); see also Ex. 334, DAD-21, Increased exposure to pollutant aerosols under high voltage power lines, Fews, Henshaw, et al., 75 Int. J. Radiat. Biol. 12, p. 1505 (1999). In searching for the mechanism for childhood and adult leukemia associated with high voltage powerlines, the authors looked for a link with another association, traffic density and its associated exhaust pollution. Id., p. 1505. This study showed that:

Excess deposition of <sup>222</sup>Rn decay product marker aerosols on surfaces mimicking the human head has not been observed outdoors under 400, 275, and 132 kV high voltage overhead transmission lines.

Id. The conclusions were:

---

<sup>30</sup> Sound is a byproduct of corona, and “annoyance from corona noise is greater than annoyance from other noises of the same level. Corona noise needed to be 10 dB(A) lower to be judged as annoying as other environmental sounds. Ex. 345, Bonneville, p. 5-24. Noise was deemed a significant issue in Minnesota, and required mitigation, but evidence on noise was not allowed on the record in the Wisconsin proceedings.

The observations demonstrate a mode of increased exposure to pollutant aerosols under high voltage power lines by increased deposition on the body. The total (indoor + outdoor) 218PO and 214PO dose to the basal layer of facial skin is estimated to be increased by between 1.2 and 2.0 for 10% of time spent outdoors under high voltage power lines.

Id., p. 1505. The following study reached this conclusion:

The Earth's natural DC field of around ~100Vm was significantly modified near powerlines in 8 out of 14 cases. Typically, downwind of the powerlines the field direction was reversed giving values to -340Vm. In one case, the effect extended more than 500m from a 275 kV line... Such space charge will result in unipolar aerosol charging in excess of the normal bipolar steady state charge distribution of pollutant aerosols. This may lead to increased lung deposition on inhalation.

Id., p. 1523. Moulder admits to the probabilities and possibilities of the Henshaw

Hypothesis:

Q: Is it your opinion that powerline corona is not capable of attracting aerosol pollutants?

A: I think that it probably is I'm not sure whether it's proven but it is reasonable that it should be able to.

Q: Is it your opinion that aerosol pollutants are not capable of being charged by powerline corona?

A: That should be possible.

Q: Is it your opinion that charged aerosol pollutants are not capable of being inhaled and retained at an elevated level because of the charge?

A: If they're charged enough, they certainly -- that certainly should be possible in the charge is enough...

Q: If all three of those things happened, they were attracted, they were charged and they were inhaled and retained, four things, could that cause a significant health effect?

lung A: If there was enough of it, it could and in fact should cause an increase in cancer if they're the right type of particles or the wrong type of particles depending on how you look at it.

Tr. at 9443-4.

There is no basis for a determination by the Commission that the particulate ionizing effects of the corona of the Arrowhead powerline, the Henshaw Hypothesis,” will not have undue adverse impact on public health and welfare.

**IX. THE ENVIRONMENTAL CONCERNS SURROUNDING THE ARROWHEAD LINE OUTWEIGH ANY RELIABILITY AND ECONOMIC BENEFIT TO THE PUBLIC**

The FEIS for the Arrowhead project unequivocally states that:

**Arrowhead-Weston/Tripoli ranks highest in terms of susceptibility to environmental impact for nine of the eleven environmental factors reviewed.**

Ex. 172, FEIS, p. 123. And WPS’ witness admits that the project has environmental impact and that the impacts must be compared with the benefits:

As I said this morning, everyone recognizes when you build a new high voltage transmission line, you are going to have some environmental impact. And it’s really a matter of public policy in terms of how much environmental impact is appropriate or tolerable in order to get the benefits of the line.

Landgren, p. 4586, see 4437, 4571.

A partial and incomplete list of environmental impacts that require additional consideration:

- Forest fragmentation – widening or cutting corridors creates disturbance
- Aesthetics – powerline structures are taller than trees. They will be visible from recreational areas such as Timm’s Hill and the Ice Age Glacier Trail. Recreational brochures don’t show transmission lines in their photos
- Mitigation shouldn’t be necessary – it is lessening the impact of damage. Don’t do the damage in the first place.
- Environmental review was a general study and not specific – need to do site inventories
- Whooping cranes, an endangered species that was planted in Juneau County with plans for procreation, could be harmed
- 200 exotic species to be concerned about were never listed, including the wild parsnip (itch weed) which is extremely irritating to humans
- Trucks will be washed down to prevent spread of noxious weeds only in wetland

- areas, but needs to be done in all areas
  - Environmental inspectors should not be utility employees who have an inherent bias
  - Ice roads 4-5" thick cannot support a fully loaded concrete truck
  - Mercury emissions will increase with increased North Dakota coal generation
  - Fish advisories over most of state that limit consumption of fish are due to power plant emissions
  - Should not cross the St. Croix Namekagon National Wild and Scenic Riverway
- X. **INTERVENOR W.O.L.F. REFUSES TO ADDRESS COMMISSION'S QUESTION AS TO WHAT SPECIFIC ROUTES SHOULD BE USED FOR THE ARROWHEAD-WESTON 345 kV TRANSMISSION LINE, AND THE TRIPOLI-RHINELANDER 115 kV TRANSMISSION LINE, BECAUSE IT ASSUMES THE LINE SHOULD BE BUILT AND ARTIFICIALLY PITS INTERVENORS AGAINST EACH OTHER.**

Intervenor W.O.L.F. strenuously objects to inclusion of a question regarding selection of specific routes in the outline presented to Intervenor. By assuming a line should be built, the Commission attempts to pit Intervenor against each other. Power can divide communities and there will be no positive result if W.O.L.F. takes a position on this false issue.

By asking Intervenor to choose what route should be used, the Commission assumes that a powerline is the answer to a ill-stated question. The question is instead whether applicants have legitimate complaints and if legitimate, how those complaints can best be addressed. W.O.L.F. has addressed those questions above. W.O.L.F. will not recommend a route to be used.

The issue before the Commission is whether the applicants have met their burden of proof -- they have not. There is no basis for a Commission determination that the project is needed. There is no basis in fact or law for the Commission's assumption that the line should be built, that it's only a matter of deciding which route should be used. Instead, the record demonstrates that the project is not needed and

that the applicants are meeting the needs of consumers. The record demonstrates that the applicants are overstating the level of increased capacity needed to meet reserve margin. The record demonstrates that the applicants are relying on a number of impossibly remote scenarios which do not show need for the line. The record demonstrates that no cost/benefit analysis has been done, that the benefits of Plan 3j are not transferrable to the Arrowhead-Weston line, that the project does not include necessary improvements and the project requires upgrade of the Forbes-Arrowhead. The record demonstrates that system outages are symptoms of utility abuse of the transmission system and disregard of its limitations. The record demonstrates that the utilities are putting their demand for economy transactions before grid security. The record shows alternatives to line have not been considered, particularly the low-voltage option, distributed generation and cogeneration, and the benefits of conservation. The record demonstrates the line is “needed” less than one day annually, and its purpose is to provide the opportunity for increased economy transactions 364 days annually and to position their corporations on the super-highway of economy transactions and bulk power transfer in today’s changing market. The record contains no basis for a Commission assumption that the line is needed..

## **XI. CONCLUSION**

The Commission must deny the applicants request for a CPCN for the Arrowhead- Weston powerline. There is no need to serve the public, and applicants have not demonstrated that the line provides any reliability benefit that could not be achieved through far more economic means. The line, as designed and proposed by applicants will not even provide the reliability benefits claimed because upgrades not



included in the application are necessary. The applicants have misrepresented the need for the line in their submissions on the record.

The purpose of this line is for market transactions to the benefit of the applicants and other utilities. The line is not in the public interest in light of the alternatives available, including the low-voltage alternative, distributed generation, cogeneration, standby generation, and Demand Side Management. Because the applicants have asked that their fiber optic application be withdrawn, they should not be permitted for fiber optic unless the docket is reopened for entry of evidence and testimony.

OVERLAND LAW OFFICE

Dated: \_\_\_\_\_

\_\_\_\_\_

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**Northern MAPP/Northwestern Ontario Disturbance  
June 25, 1998**

**\*\*\* FINAL REPORT \*\*\***

**Power System Disturbance Report**

**Compiled by:**

Mid-Continent Area Power Pool (MAPP)

**MAPP Committees:**

Iowa Operating Review Working Group (IORWG)  
Nebraska Operating Review Working Group (NORWG)  
Northern MAPP Operating Review Working Group (NMORWG)

Ontario Hydro

**Approved by:**

MAPP Operating Review Subcommittee (ORS) on September 2, 1998

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## Executive Summary

The cause of the disturbance on June 25, 1998, was a trip of the NSP King-Eau Claire 345kV line at 02:18 CDT along with the prior outage of the Prairie Island-Byron 345kV, which had tripped earlier at 01:34 CDT and could not be reclosed due to a high phase angle across the open breaker. The NSP Operators were focusing on closing the Prairie Island-Byron 345kV line at the time of the subsequent King-Eau Claire 345kV line trip.

The system was in an insecure state following the Prairie Island-Byron 345kV line trip, and not able to withstand the next contingency. The TCEX flow was 1004 MW, and had not been reduced by the NSP System Operators to achieve the safe Operating Guide stability limit of 700 MW prior to the subsequent King-Eau Claire 345kV line trip. Following the King-Eau Claire 345kV trip, the remaining underlying transmission lines out of the Twin Cities area were significantly overloaded and began tripping, and the cascading tripping continued until the entire northern MAPP region was separated from the Eastern Interconnection.

The impact of the disturbance was widespread, affecting the entire MAPP region and the Northwestern Ontario Hydro (OH) system. Northern MAPP separated from the Eastern Interconnection forming several islands, and resulting in the eventual blackout of the Northwestern OH system. In the MAPP region, more than 60 transmission lines tripped, over 4,000 MW of generation was lost, and more than 39,000 customers were affected by the loss of over 300 MW of load. In the Northwestern OH system, all of the tie lines tripped, about 270 MW of generation was lost, and more than 113,000 customers were affected by the loss of 650 MW of load.

No major damage to equipment was reported as a result of the disturbance. The system restoration was accomplished well by the System Operators, with the systems returning to normal within 19 hours after the disturbance began.

The MAPP Operating Standards were violated during this incident. The system was not re-adjusted immediately to a secure operating condition prior to the next contingency. NERC Operating Policies were also violated during the disturbance.

The primary recommendations of this report are:

1. The system must be operated within approved Operating Guide limits.
2. Following a contingency, the system must be returned to a reliable state within the readjustment period allowed in the MAPP Standards. Operating Guides must be reviewed to ensure procedures exist to restore system reliability in the allowable time periods.

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4. Phase angle restrictions that can prevent reclosing of major interconnections during system emergencies should be reviewed and approved by the MAPP Operating Review Subcommittee (ORS). MAPP should seriously consider bypassing synchrocheck relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.

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**ABBREVIATIONS**

|         |                                                         |
|---------|---------------------------------------------------------|
| AEP     | American Electric Power                                 |
| AGC     | Automatic Generation Control                            |
| ALT     | Alliant Utilities                                       |
| BEPC    | Basin Electric Power Cooperative                        |
| CBPC    | Corn Belt Power Cooperative                             |
| CCS     | Coal Creek Station                                      |
| CP      | Cooperative Power                                       |
| CU DC   | Cooperative Power/United Power Association DC line      |
| DPC     | Dairyland Power Cooperative                             |
| EM      | MAPP Emergency Replacement Procedure                    |
| FERC    | Federal Energy Regulatory Commission                    |
| GGG     | Gerald Gentleman Station                                |
| IES     | Alliant Utilities-IES Utilities, Inc.                   |
| IORWG   | Iowa Operating Review Working Group                     |
| IPW     | Alliant Utilities-Interstate Power Company              |
| KCPL    | Kansas City Power & Light                               |
| LES     | Lincoln Electric System                                 |
| LLR     | Line Loading Relief Procedure                           |
| MAIN    | Mid-American Interconnected Network                     |
| MAPP    | Mid-Continent Area Power Pool                           |
| MCN     | MAPP Communications Network                             |
| MDU     | Montana-Dakota Utilities                                |
| MEC     | MidAmerican Energy Company                              |
| MH      | Manitoba Hydro                                          |
| MHEX    | Manitoba Hydro Export (See Appendix #4 for definition.) |
| MP      | Minnesota Power                                         |
| MPC     | Minnkota Power Cooperative                              |
| MPW     | Muscatine Power and Water                               |
| NDEX    | North Dakota Export (See Appendix #4 for definition.)   |
| NMORWG  | Northern MAPP Operating Review Working Group            |
| NORWG   | Nebraska Operating Review Working Group                 |
| NPPD    | Nebraska Public Power District                          |
| NSP     | Northern States Power Company                           |
| NW OH   | Northwestern Ontario Hydro System                       |
| NWPS    | Northwestern Public Service Company                     |
| OASIS   | Open Access Same Time Information System                |
| OH      | Ontario Hydro                                           |
| OPPD    | Omaha Public Power District                             |
| OTP     | Otter Tail Power Company                                |
| RTU     | Remote Terminal Unit                                    |
| SPC     | SaskPower                                               |
| SPP     | Southwest Power Pool                                    |
| SQBT DC | Square Butte DC line                                    |
| TCEX    | Twin Cities Export (See Appendix #4 for definition.)    |
| WAPA    | Western Area Power Administration                       |

## 1. INTRODUCTION

### 1.1 Description of the Disturbance:

In the early morning of June 25th the MAPP system was operating with heavy transfers east to MAIN and south to SPP. In particular, the sum of the loading on the three 345kV interconnections going east and south from the Twin Cities of Minneapolis and St. Paul, Minnesota were approximately 1578 MW which is near the established transfer limit for the Twin Cities Export (TCEX). At 01:34 CDT a thunderstorm initiated a single line to ground fault on the Prairie Island to Byron 345kV line, a segment of the interconnection from the Twin Cities south to Iowa. The line was carrying 636 MW at the time. While the fault was only temporary, a large standing phase angle across the open line breaker prevented the Northern States Power (NSP) System Operators from manually reclosing the line.

NSP System Operators called for small reductions in the Twin Cities export, but were unable to close the breaker and return the line to service. While this effort was in progress the King-Eau Claire 345kV line was tripped by a single line to ground fault at 02:18 CDT. This is a major interconnection from the Twin Cities to MAIN and is typically the most heavily loaded of the three Twin Cities interconnections. At the time of the trip it was loaded at about 1048 MW, and the TCEX flow was 1004 MW. Loss of this line with the Prairie Island-Byron 345kV line still open represented a subsequent contingency at the export level that existed, and was beyond the capability of the system at that time.

Soon after loss of the second 345kV interconnection critical underlying sub-transmission interconnections began to trip due to the overloads caused by the outages of the two 345kV Twin Cities export ties. At 02:21 CDT cascade tripping of the remaining ties between the northern MAPP region and the rest of the eastern interconnection occurred. The separated area consisted of large portions of Minnesota, North Dakota, South Dakota, Montana, and Wisconsin in the U.S. and the Canadian provinces of Manitoba and Saskatchewan. The separation event produced large voltage and frequency excursions, and a number of generating units tripped off line as a result.

The loss of the two 345kV Twin Cities export ties and underlying 115/161kV system, caused the flows on the two interconnections between MAPP and the northwestern Ontario Hydro system to increase substantially. Before the disturbance, both of these tie lines were supplying power to Ontario. These ties both tripped, and their loss initiated a disturbance that led to the tripping of the 230kV ties linking the northwestern Ontario Hydro system to the east. Cascade tripping led to the creation of a northwest Ontario island that was very deficient in generation. Shortly thereafter, most of the load (650 MW) was lost in the region other than a 20 MW island that formed around the Manitou Falls plant.

In addition to providing input to this report, Ontario Hydro will issue a separate report addressing their NW System collapse and restoration in more detail.

The complete list of people who contributed to the development of this report is included in Appendix #1.

### **1.3 Cause and Impact of Disturbance:**

The cause of the disturbance was a trip of the NSP King-Eau Claire 345kV line at 02:18 CDT along with the prior outage of the Prairie Island-Byron 345kV line. The Twin Cities Export (TCEX) at the time of the King-Eau Claire 345kV line trip was approximately 1004 MW. The NSP Prairie Island-Byron 345kV line had tripped earlier at 01:34 CDT and could not be reclosed due to a high phase angle across the open breaker. The NSP Operators were focusing on closing the Prairie Island-Byron 345kV line at the time of the subsequent King-Eau Claire 345kV line trip.

The system was in an insecure state following the Prairie Island-Byron 345kV line trip, and not able to withstand the next contingency. The TCEX flow was not reduced by the NSP System Operators to achieve the safe Operating Guide stability limit of 700 MW prior to the subsequent King-Eau Claire 345kV line trip. Following the King-Eau Claire 345kV trip, the remaining underlying transmission lines out of the Twin Cities area were significantly overloaded and began tripping, and the cascading tripping continued until the entire northern MAPP region was separated from the Eastern Interconnection.

The impact of the disturbance was widespread, affecting the entire MAPP region and the Northwestern Ontario Hydro (OH) system. Northern MAPP separated from the Eastern Interconnection forming several islands, and resulting in the eventual blackout of the Northwestern OH system. The affected regions are shown in Figure #1. A significant amount of generation and load was lost during the disturbance. Significant voltage and frequency excursions, heavy transmission loading and power surges also occurred during the disturbance. No major damage to equipment was reported as a result of the disturbance.

#### **1.3.1 Duration of Disturbance, Return to Normal:**

The disturbance began on Thursday, June 25, 1998, at approximately 02:18 Central Daylight Time (CDT) following the trip of the NSP King-Eau Claire 345kV line.

The duration of the disturbance and subsequent system restoration until the system was returned to normal operation was approximately 4 hours 27 minutes in Northwestern Ontario, and approximately 19 hours in the MAPP region. All of the transmission, except those lines damaged by the storm, were returned to service by 05:49 CDT in the MAPP region and by 06:00 CDT in Northwestern

Frequency in the northern MAPP island increased to about 61 Hz due to the excess generation in the island. The western portion of the island in particular had a large unbalance in load and generation. At about 02:25 CDT, a major DC transmission line linking the western and eastern areas of the island tripped. This overloaded the parallel AC ties, and a cascade of line tripping separated the eastern and western portions of the island. The Manitoba and Saskatchewan systems remained connected to the eastern island, which consisted of most of Minnesota and a small portion of northwestern Wisconsin. The western island consisted of the North Dakota, northern South Dakota, and western Minnesota systems.

After this separation frequency in the eastern island (which included the Twin Cities) settled very close to 60 Hz, and automatic reclosing of a 115kV line in northwestern Wisconsin successfully reconnected the eastern island to the Eastern Interconnection about 3 minutes and 50 seconds after the initial island was formed. This reconnection occurred about 12 seconds after the eastern and western portions of the initial island separated.

Frequency of the western island increased above 63 Hz, and several units tripped on overfrequency. Frequency stabilized between 61 and 62 Hz. Operators reduced generation, and the island was reconnected to the Eastern Interconnection at 03:03 CDT, 41 minutes after the initial separation.

In the U.S., the loss of load was confined primarily to customers near the island boundaries that were tripped during the islanding sequence. Most of these outages were a direct result of the lines tripping or caused by the resulting voltage and frequency oscillations. Approximately 313 MW of load was lost. Service was restored to all customers by 06:45 CDT that morning, although some industrial customers did not achieve full load until the next day. In Ontario, about 650 MW of load was lost. System restoration there began at 03:12 CDT and was essentially complete by 06:45 CDT.

A total of approximately 4,171 MW of generation was lost during the event. This generation was returned to service at various times, but was all available within 12 hours of the event. No major equipment damage was reported.

## **1.2 Systems/Individuals Who Prepared Report:**

This disturbance report was compiled by the Mid-Continent Area Power Pool (MAPP) staff, the following formal MAPP Committees, and representatives from Ontario Hydro (OH):

- Iowa Operating Review Working Group (IORWG)
- Nebraska Operating Review Working Group (NORWG)
- Northern MAPP Operating Review Working Group (NMORWG)

Ontario. One Dairyland Power Cooperative (DPC) transmission line, damaged by the storm, was returned to service on 6/27/98.

The Ontario Hydro system was restored to normal at about 6:45 CDT with exception of some of the industrial loads. This system restoration started at 3:12 CDT.

The table below shows the times that each of the individual systems began losing transmission, generation, and load, and the subsequent times that each was returned to normal. All times shown are CDT on 06/25/98, unless otherwise noted.

**Table 1-Outage Durations (Reported by Systems)**

| COMPANY | TRANSMISSION |                       | GENERATION |       |       |                       |
|---------|--------------|-----------------------|------------|-------|-------|-----------------------|
|         | BEGIN        | END                   | BEGIN      | END   | BEGIN | END                   |
| BEPC    | 02:22        | 04:13                 | 02:26      | 10:01 | N/A   | N/A                   |
| CP      | N/A          | N/A                   | N/A        | N/A   | 02:21 | 14:00                 |
| DPC     | 02:01        | 06/27/98 <sup>1</sup> | N/A        | N/A   | 02:18 | 03:43                 |
| IPW     | 02:19        | 03:53                 | 02:22      | 04:38 | 02:19 | 03:44                 |
| MDU     | 02:22        | 03:08                 | 02:26      | 13:54 | 02:22 | 03:33                 |
| MEC     | 02:22        | 04:14                 | 02:22      | 08:41 | N/A   | N/A                   |
| MH      | 02:21        | 03:34                 | 02:22      | 02:51 | N/A   | N/A                   |
| MP      | 02:21        | 05:17                 | N/A        | 03:03 | 02:22 | 06/26/98 <sup>2</sup> |
| MPC     | 02:27        | 04:14                 | 02:26      | 13:54 | N/A   | N/A                   |
| NPPD    | N/A          | N/A                   | N/A        | N/A   | 02:22 | 05:20                 |
| NSP     | 02:18        | 04:22                 | 02:21      | 11:15 | 02:18 | 03:00                 |
| OH      | 03:12        | 06:00                 | 03:12      | 09:35 | 03:12 | 06:45                 |
| OTP     | 02:21        | 05:49                 | 02:21      | 09:49 | 02:21 | 05:49                 |
| SPC     | N/A          | N/A                   | 02:22      | 03:16 | N/A   | N/A                   |
| UPA     | 02:25        | 04:22                 | 02:25      | 04:45 | N/A   | N/A                   |
| WAPA    | 02:21        | 03:35                 | 02:22      | 03:57 | N/A   | N/A                   |

("N/A" - Not applicable because no outages were reported)

During the disturbance, several MAPP Members and the MAPP Security Center suspended the Standards of Conduct under FERC Orders 888/889 due to the emergency conditions.

The table below shows the systems that suspended compliance with the FERC Orders 888/889 during the disturbance. The times that the MAPP Members

<sup>1</sup> DPC Alma-Rock Elm 161kV line, which lost 5 structures due to storm, was restored on 6/27/98.

<sup>2</sup> MP's Lake Superior Paper customer was back to 100% load at about 05:00 on 6/26/98.

notified the MAPP Security Center of changes or expected changes in the status of compliance with the FERC Orders are shown in [ ]'s.

**Table 2-FERC 888/889 Suspension Durations (Reported by Systems)**

| <b>Company</b> | <b>Time Standards of Conduct<br/>Suspended (CDT) [MCN<br/>Broadcast]</b> | <b>Time Standards of Conduct<br/>Reinstated (CDT) [MCN<br/>Broadcast]</b> |
|----------------|--------------------------------------------------------------------------|---------------------------------------------------------------------------|
| NSP            | 02:23 [02:23]                                                            | 05:00 [04:32]                                                             |
| WAPA           | 02:21 [02:32]                                                            | 04:36 [04:36]                                                             |
| MAPP           | 02:34 [02:34]                                                            | 21:00 [21:00]                                                             |
| ALT            | 02:30 [Not Reported]                                                     | 05:00 [04:56]                                                             |
| NSP            | 11:00 [10:18]                                                            | 18:00 [17:20]                                                             |

NSP suspended compliance with FERC Orders 888/889 twice during the disturbance. The first was for approximately 2-1/2 hours due to the emergency conditions during the system breakup. The second was later on 6/25/98 for approximately 7 hours due to emergency conditions in NSP's service territory due to loss of generation resulting from the event and a forecasted 1000 MW generation deficit.

WAPA (Upper Great Plains Region) suspended compliance with FERC Orders 888/889 for approximately 2 hours due to the emergency conditions during the system breakup.

Alliant suspended compliance with FERC Orders 888/889 during the disturbance for approximately 2-1/2 hours due to the emergency conditions during the system breakup.

The MAPP Security Center also suspended compliance with FERC Orders 888/889 for approximately 18-1/2 hours due to emergency conditions in the MAPP region during the system breakup and during the subsequent system restoration.

NSP, WAPA, and Alliant posted notice of the emergency suspensions of the Standards of Conduct on the OASIS within the required 24 hours after the emergency.

There is no specific time indication when the MAPP system returned to condition "green". The system condition in the MAPP Security Center remained "yellow" at 21:00 CDT, because the DPC Alma-Rock Elm 161kV line was still out of service with 5 structures down. Even in "yellow" condition, the MAPP Security Center Operator (SCO) on duty considered the MAPP system essentially back to normal at 21:00 CDT, 18 hours and 42 minutes after disturbance started. The Alma-Rock Elm 161kV line was restored to service 2 days later on 6/27/98. System

condition "green" was not achieved following this disturbance due to subsequent storm related outages the following day on 6/26/98.

### **1.3.2 Magnitude of Load Lost, Number of Customers Affected:**

In the MAPP region, the disturbance resulted in the loss of approximately 313 MW of load affecting approximately 39,000 customers.

The Northwestern OH system lost approximately 650 MW of load affecting 113,770 municipal and retail customers and 23 direct industrial customers.

The total load lost as a result of the disturbance was approximately 913 MW.

### **1.3.3 Transmission Losses, Islanding:**

The sequence of events (Appendix #5) shows the major transmission lines tripped during the disturbance resulting in the formation of islands. Due to the cascading effect after the loss of Prairie Island-Byron 345kV line and King-Eau Claire 345kV line, numerous AC transmission lines tripped producing separations and islands throughout the MAPP and Ontario Hydro regions as shown in Figure #1.

Figure #2 shows the major transmission lines that tripped in the MAPP area and identifies the separations and islands formed in MAPP during the disturbance. In the figure, the black dots identify the lines that tripped during the initial separation between northern and southern MAPP, starting between Minnesota and Wisconsin, forming the Minnesota/Manitoba/North Dakota/Saskatchewan island. They also show the lines into MAPP that tripped separating the Northwestern Ontario Hydro system from MAPP. The red dots identify the lines that tripped during the subsequent separation between North Dakota and Minnesota forming the North Dakota island.

In the MAPP AC transmission system eight (8) 345kV lines, thirteen (13) 230kV lines, eight (8) 161kV lines, fourteen (14) 115kV lines, and at least nineteen (19) 69kV lines were lost. The Ontario Hydro Northwestern system was also severely affected by the disturbance. After losing the ties with MH and MP at 02:21 CDT, the NW Ontario Hydro system collapsed approximately 2 minutes later. The affected substations in NW OH are shown in the one-line diagram in Figure #3.

The disturbance also affected the DC lines in the MAPP region. Pole 1 of the CU DC line was manually tripped in an attempt to reduce the CU DC line power flow. This action increased the AC voltage at the Coal Creek Station and 28 seconds later CU pole 2 tripped on an overvoltage protection. Both poles were lost from 02:25 to 03:45 CDT. The Square Butte DC pole 2 also tripped from an over-frequency protection and was out from 02:25 to 03:48 CDT. The CU DC

line tripping caused a separation between North Dakota and Minnesota forming the North Dakota island. Once North Dakota was separated from the larger island, the frequency in the Minnesota area quickly dropped to near 60 Hz (as shown in Figure #11) allowing a rapid automatic reconnection of the Minnesota/Manitoba/Saskatchewan island to the Eastern Interconnection

During the disturbance, the system separations formed the following islands: (See Figure #1).

- Separation between Minnesota and the Western Wisconsin system at 02:21:31 CDT.
- Separation of Northwestern Ontario Hydro from Manitoba and Minnesota at about 02:21:55 CDT and total collapse of the Northwestern OH system at 02:22:04 CDT when the East-West ties tripped.
- Formation of the Minnesota/Manitoba/North Dakota/Saskatchewan island at 02:22:09 CDT
- Formation of the North Dakota island at 02:25:47 CDT.

Minnesota, Manitoba, Saskatchewan and Western Wisconsin were tied back together at 02:25:59 CDT when the Ironwood-Park Falls 115kV line automatically reclosed about 12 seconds after the formation of the North Dakota island.

The North Dakota island was reconnected to the Eastern Interconnection at about 03:03:39 CDT when the Bismarck-Glenham 230kV line was manually closed.

The frequency in each of the islands that formed, compared to the frequency in the southern MAPP system that remained tied to the Eastern Interconnection, is shown in Figures #4 and #5.

### **1.3.4 Significant Frequency and/or Voltage Excursions:**

Large frequency excursions took place when the initial Minnesota/Manitoba-Saskatchewan/North Dakota island was formed. The maximum frequency excursion, observed by the Dynamic System Monitor (DSM) at the Arrowhead 230kV bus, was 61.11 Hz and the minimum 59.48 Hz. MP also reported a maximum frequency of 61.2 Hz.

When this island formed, the southern MAPP system that remained tied to the Eastern Interconnection also experienced significant frequency excursions. Frequency reached values from 60.04 Hz down to 59.91 Hz in the DPC area. IPW reported similar values (minimum 59.925 Hz and maximum of 60.015 Hz). In Nebraska, NPPD reported excursions from 59.5 Hz to 60.066 Hz. In Iowa, MEC recorded frequency excursions from 59.74 Hz to 60.04 Hz.



Following the separation of North Dakota from the initial island, the maximum frequency excursion recorded was 62.2 Hz. Following several generating unit trips, the North Dakota island frequency oscillated around approximately 61.3 Hz for about 30 minutes. An undetermined action occurred at about 02:53 CDT, and the North Dakota island frequency began to ramp down to 60.9 Hz over the next 6 minutes. Another change occurred at about 02:59 CDT, at which time the frequency began ramping down at a faster rate to 60.1 Hz at about 03:03 CDT, just prior to the reconnection of the North Dakota island to the Eastern Interconnection.

In the Northwestern Ontario Hydro system, the frequency went as low as 55 Hz. This initiated under-frequency load shedding protection schemes. However the system voltage continued to decay and the system collapsed.

Significant voltage excursions were recorded throughout the system during the disturbance.

Outside of the islands that formed, voltage excursions down to 0.87 p.u. were recorded at the Barron 161kV bus (northwestern Wisconsin). Alliant-IPW reported voltage excursions between 0.838 p.u. to 1.144 p.u.

The pre-disturbance operation values at Arrowhead 230kV bus (near Duluth Minnesota) were close to 138.8kV (phase to ground). During the disturbance, the voltage reached values as high as 142kV, and as low as 132kV. The voltage excursions at the King 345kV bus (just northeast of the Twin Cities) reached values from 335.45kV up to 377kV (the operational values pre-disturbance were about 350kV).

In the North Dakota island, voltage increased substantially after the separation from Minnesota. The Jamestown 115kV bus (central North Dakota) voltage was close to 118kV before the disturbance. Following the separation, the maximum voltage excursion was 128kV, and the minimum 113kV.

Significant voltage oscillations were recorded throughout the MAPP system during the approximately 5 minutes that the North Dakota system was asynchronous with Minnesota and still connected by one 115kV tie. The voltages at buses far from the tie line that the systems were slipping across can be seen in Figures #15 and #16 which show the King 345kV bus voltage in Minnesota and the Center 230kV bus voltage in central North Dakota. As seen in Figure #13, the voltages in North Dakota were oscillating by up to 8kV on central North Dakota 230kV buses.

## 2. CONCLUSIONS

### 2.1 Operating Conditions at time of Disturbance

#### 2.1.1 MAPP/Northwestern OH Systems were within Operating Guide limits prior to initial outage

Prior to the initial outage of the Prairie Island-Byron 345kV line, the MAPP and Northwestern Ontario Hydro (OH) systems were operating within Operating Guide limits. However, the MAPP to MAIN interface was heavily loaded. The TCEX flow<sup>3</sup> was at its stability limit (with TCEX generation sensitivity adjustments applied) at 01:15 CDT. The Eau Claire-Arpin 345kV line flow was also at its allowable flow limit, and initial NERC TLR schedule collections had been requested earlier at 23:24 CDT on 6/24/98 to prepare for possible curtailments.

A severe thunderstorm was moving across the Twin Cities (Minnesota) area towards the east into Wisconsin prior to the disturbance.

#### 2.1.2 Prairie Island-Byron 345kV line trip set up insecure operating condition prior to disturbance

The NSP Prairie Island-Byron 345kV line tripped at 01:34 CDT following a phase A to ground fault.

The high TCEX flow conditions during the early morning hours of 6/25/98 coupled with the trip of the Prairie Island-Byron 345kV line at 01:34 CDT, resulted in a violation of an Operating Guide limit or NERC Operating Security Limit<sup>4</sup> as defined by the latest NERC Operating Policy 2 (effective 7/1/98). Following the trip of the Prairie Island-Byron 345kV line, the system was operating in an insecure state because the TCEX flows were higher than the TCEX limit, and was not protected against the next contingency. There are no automatic readjustment<sup>5</sup> actions in place for any of the three 345kV lines comprising the TCEX interface.

#### 2.1.3 NSP Operators focused on restoration of Prairie Island-Byron 345kV line

Following the trip of the Prairie Island-Byron 345kV line at 01:34 CDT, NSP Operators reported that they were focusing on restoring the line as quickly as possible. The actions taken by the NSP Operators in this timeframe are outlined in the sequence of events. The line was energized successfully from one end, indicating that the line was okay. If the line could have been closed, the system

<sup>3</sup> Twin Cities Export (TCEX) is the sum of flows on the NSP lines out of the Minneapolis/St Paul (Twin Cities) area: Eau Claire-Arpin 345kV line, the Byron-Adams 345kV line, and the Wilmarth-Lakefield 345kV line. (See Appendix #4)

<sup>4</sup> NERC Operating Manual, Policy 2, Operating Security Limit Definition: "Operating Security Limits define the acceptable operating boundaries."

<sup>5</sup> MAPP Reliability Handbook, MAPP Operating Standards, Section 9.4.1 "Definitions".

would have been restored to a secure condition. However, the line could not be closed because there was an approximate 41-42 degree phase angle across the open line, and the protective lockout at Byron Substation prevented closing of the line for angles > 40 degrees. NSP Operators requested MAPP LLR schedule curtailments, in relatively small amounts, which were targeted at reducing the phase angle by 1-2 degrees. However, this small angle reduction was not achieved prior to the next major contingency of the King-Eau Claire 345kV line trip.

The NSP system load and generation during the 01:34 to 02:18 CDT timeframe, was relatively constant. Most of NSP's load that was lost as a result of the storm was lost before the Prairie Island-Byron 345kV line tripped. Sherco units #1, #2, and #3 were left on AGC during the attempts to lower Prairie Island generation and reclose the Prairie Island-Byron 345kV line. Sherco generation increased about 150 MW over the same time frame that Prairie Island generation was decreased by about 60 MW as a result of the AGC action.

NSP has since indicated that the phase angle limit for the manual re-close at Byron on the Prairie Island-Byron 345kV line can likely be increased to 50-55 degrees, from the existing limit of 40 degrees. If this change would have been in-place on June 25th the Prairie Island-Byron 345kV line could have been manually re-closed before the storm hit the Eau Claire area and the next major contingency occurred.

#### **2.1.4 Twin Cities Export (TCEX) Prior Outage Operating Guides exceeded**

Following the initial outage of the Prairie Island-Byron 345kV line, the TCEX flow was still approximately 1000 MW at 02:15 CDT (42 minutes after the line trip), which is above the Operating Guide limit. The MAPP approved Operating Guide for the Prairie Island-Byron 345kV outage limits the TCEX to 700 MW to protect system stability. The Operating Guide also shows that TCEX can be limited further by post-contingent steady state transmission loading and voltage limits, under some conditions. The post-contingent steady state transmission loading and voltage limits were monitored by the NSP Operators using on-line analysis and dynamic line ratings. Based on the operating conditions at the time, the NSP Operators determined that no excessive post-contingent overloads existed.

② The TCEX flow was approximately 200 MW above the adjusted stability limit, even after the sensitivity adjustments to the TCEX limit based on Sherco generation levels and local Twin Cities metro area generation patterns were applied. This can be clearly seen in Figure #17, which shows the TCEX flows during the day on June 25<sup>th</sup>, and the TCEX limit as calculated by the NSP Operators. The NSP Operator focus was on reducing the phase angle to allow reclosing of the Prairie Island-Byron 345kV line, which had been successfully

energized from both ends, and not on reducing flows to reduce TCEX to the prior outage limit.

### **2.1.5 TCEX Sensitivity adjustment not demonstrated for Prior Outages**

The sensitivity adjustment to the TCEX stability limit, based on Sherco generation levels and local Twin Cities metro area generation patterns, had not been demonstrated for prior outage conditions or approved by the appropriate MAPP Committees for use in the TCEX prior outage Operating Guides.

### **2.1.6 TCEX flow not reduced in time to sufficiently protect for next contingency**

During high TCEX flow conditions, such as those that were present prior to the disturbance, the TCEX flows will be above Operating Guide limits immediately following a trip of one of the 345kV lines comprising the TCEX interface until the system can be readjusted to protect for the next contingency. The MAPP Design Standards and MAPP Operating Standards<sup>6</sup> require the control area operator to readjust the system immediately to restore the reliability of the system. The MAPP Design Standards allowable readjustment period is the 10 minutes immediately following the contingency<sup>7</sup>. The MAPP Operating Standards definition of the readjustment period is somewhat broader regarding the time periods allowed to restore the facility loadings<sup>8</sup> to acceptable levels. This MAPP requirement is more stringent than the requirement in the NERC Operating Standards<sup>9</sup>, effective 7/1/98, which require the control area operator to readjust the system to within Operating Security Limits as soon as possible, but not longer than 30 minutes following the initial contingency.

In this case, no significant system readjustments to protect for the next major contingency had been implemented within 44 minutes after the initial 345kV line trip. The primary reason was the NSP Operator's expectation that the Prairie Island-Byron 345kV line could be returned to service once the phase angle could be reduced sufficiently. The King-Eau Claire 345kV line tripped approximately 44 minutes after the initial outage of the Prairie Island-Byron 345kV line, before the system conditions had been readjusted sufficiently to allow the system to survive this subsequent line trip. If the TCEX flow would have been reduced to

<sup>6</sup> MAPP Operating Standards & MAPP Design Standards (Section 9, MAPP Reliability Handbook): Readjustment – "Manual or conventional automatic action taken immediately following a disturbance to restore the Reliability of the system under conditions then existing. Permissible Readjustments for operating studies are listed in the Appendix."

<sup>7</sup> MAPP Design Standards (Section 9, MAPP Reliability Handbook), Appendix II, Permissible Readjustments: "The Readjustment period is the 10 minutes immediately following a contingency in which actions can be performed to address the contingency."

<sup>8</sup> MAPP Operating Standards (Section 9, MAPP Reliability Handbook), Appendix, Permissible Readjustments: "The Readjustment period is the time immediately following a contingency in which actions can be performed to keep facilities within emergency loading limits and emergency voltage limits. The length of the readjustment period will be 10 minutes to restore voltage levels to acceptable voltage levels. The readjustment period to keep loading within emergency limits is normally 10 minutes, however, this time period may be extended to the length of time the member has agreed the overloaded facility can exceed its normal rating when originally defining the emergency loading limits for the facility."

<sup>9</sup> NERC Operating Manual, Policy 2, Standard 2 (January 5, 1998)

the Operating Guide limit of 700 MW prior to the King-Eau Claire 345kV line trip, the disturbance may have been prevented.

### **2.1.7 MAPP Security Center Operator (SCO) not sufficiently aware of severity of system conditions prior to disturbance**

The MAPP SCO was aware of the Prairie Island-Byron 345kV outage, and was working with the NSP Operator prior to the disturbance to attempt to reduce the TCEX to allow reclosure of the line.

NSP has indicated that the severity of the current system conditions, and the fact that the system conditions were beyond stability limits, was not communicated effectively to the MAPP SCO. The MAPP Security Center (SC) did not have the adjusted TCEX limit available, as calculated and used by the NSP Operators, and therefore could not determine precisely if the TCEX was above the Operating Guide limit, or when it was adjusted back within the Operating Guide limit.

However, the MAPP SCO should have been aware of the TCEX Operating Guide limit of 700 MW for the Prairie Island-Byron 345kV prior outage. Also, based on the high TCEX value at the time, the MAPP SCO should have been aware of the urgency of reducing TCEX for that condition because system instability was probable for a subsequent contingency.

## **2.2 Procedures utilized by NSP Operators for reducing Twin Cities Export (TCEX)**

### **2.2.1 MAPP Line Loading Relief (LLR) Procedure requests by NSP Operators not large enough to reduce TCEX sufficiently to achieve Operating Guide limits or reduce phase angle sufficiently**

With the Prairie Island-Byron 345kV line prior outage, the TCEX value was approximately 300 MW above the Operating Guide limit of 700 MW at 02:15 CDT (191 MW above the adjusted TCEX limit of 813 MW-which has not been demonstrated as outlined in section 2.1.5). The NSP Operators requested 50 MW of relief on the Eau Claire-Arpin 345kV line at 01:51 CDT in an attempt to reduce the standing phase angle on the open line. The 50 MW request is the standard increment typically requested by NSP for TCEX curtailments. Approximately 246 MW of schedule curtailments were subsequently requested by the MAPP SCO, and implemented by the Member systems. The NSP Operators later requested an additional 100 MW of relief on the Prairie Island-Byron 345kV line (which was still open) at 02:10 CDT. No schedule curtailments were requested by the MAPP SCO for the 100 MW LLR request prior to the subsequent trip of King-Eau Claire 345kV line at 02:18 CDT.

The total relief obtained on the TCEX interface through the MAPP LLR procedure prior to 02:18 CDT when the disturbance occurred was 50 MW, which was insufficient to reduce the phase angle on the open Prairie Island-Byron 345kV line to allow it to be reclosed or to reduce the TCEX flow to the prior outage Operating Guide limit of 700 MW.

**2.2.2 MAPP Line Loading Relief (LLR) Procedure, in its current state, cannot be used effectively for emergency conditions where the system is in an insecure state**

The MAPP LLR procedure cannot be relied upon to implement export reductions to achieve a secure operating condition within the readjustment period allowed in the MAPP Design or Operating Standards, or even within the maximum 30 minute readjustment period allowed in the NERC Operating Standards. The LLR process requires several manual steps, which are time consuming, and the execution time of the LLR program itself varies and can be lengthy. In addition, implementation of the procedure for schedule curtailment requests requires additional time, and a significant amount of communications between the MAPP SCO, MAPP Member Operators, Marketers slows down the implementation of the requested schedule curtailments. It can be difficult to achieve requested schedule curtailments quickly.

In the case of the first LLR request made by NSP for 50 MW at 01:51 CDT, the request was made approximately 16 minutes after the Prairie Island-Byron 345kV line tripped. The MAPP SCO responded to the request within 3 minutes, and requested the MAPP systems to implement schedule curtailments as soon as possible, or by 02:00 CDT at the latest. This introduced another 6 minutes of delay. Factoring in a minimum 5 minute schedule change ramp, the total time to implement the first 50 MW of relief was approximately 30 minutes. The MAPP SCO has indicated that the timing of this particular LLR request was ideal, and that other LLR requests may take significantly longer. The MAPP SCO has also indicated that MAPP Members routinely call and question the requested schedule curtailments, which may further delay implementation of the schedule curtailments.

The MAPP LLR procedure is an effective tool used by the MAPP Members to prevent overloading facilities before the system reaches an insecure state, and can be used in those "emergency" type situations where it can provide required relief within the allowable time constraints. Any Member of the MAPP Regional Transmission Committee (RTC) that owns transmission facilities in the RTC region may request MAPP to initiate the LLR procedure if it determines that one of its facilities is presently overloaded or may overload (i.e., exceed either its normal or emergency rating).

The goal of the MAPP LLR procedure is to unload transmission elements in a manner that does not jeopardize the reliability of the bulk transmission system and is fair to all transmission owners and transmission users. The LLR procedure identifies transactions, on a priority basis, which are impacting a facility which is at or near its safe operating limit, and identifies schedule curtailments to achieve the requested relief to reduce the loading of the facility to normal levels.

### **2.2.3 Other Permissible Readjustments must be used to restore system reliability within the allowable time criteria**

The MAPP LLR procedure cannot be used effectively to readjust the system back to a secure operating condition following contingencies, because it cannot be implemented quickly enough to restore the reliability of the system. Other system readjustments, as allowed for in the MAPP Operating Standards<sup>10</sup>, should have been implemented following the trip of the Prairie Island-Byron 345kV line. These permissible readjustments include: generation rejection, generation reductions, reduction of economy exports to the extent possible within the readjustment period, adjustment of Load Tap Changing (LTC) transformers, phase shifters, or HVDC flows.

The NSP Operators implemented generation reduction at the NSP Prairie Island plant, but the reduction achieved was insufficient to reduce the TCEX within the Operating Guide limit prior to the next contingency (-63 MW from 01:13 to 02:17 CDT). This reduction was offset by generation increases in the control area due to AGC response.

### **2.2.4 MAPP Line Loading Relief (LLR) Procedure failed for request for relief on the open Prairie Island-Byron 345kV line**

The second NSP LLR request for 100 MW of relief on the Prairie Island-Byron 345kV line (which was still open) was ineffective. The powerflow model used by the LLR process includes current outages in the MAPP system, and already had the Prairie Island-Byron 345kV line modeled out of service. The program, which determines the schedule curtailments, did not warn the MAPP SCO that the line (for which relief had been requested) was already out in the model, and therefore no schedules would have a power flow distribution factor (DF) across the line, and no schedules were identified for curtailment. The LLR schedule curtailment request, which was broadcast to the MAPP Member Operators, requested no schedule curtailments due to this shortcoming in the LLR program.

However, even if the second LLR request had been processed properly, there would have been no time for MAPP Member Operators to implement any schedule curtailments prior to the time the next major contingency occurred.

<sup>10</sup> MAPP Operating Standards, Permissible Readjustments.

### **2.2.5 Operating Guides not available for reduction of high phase angle across open Prairie Island-Byron 345kV line**

The NSP Operators did not have formal procedures or Operating Guides available to identify specific actions to effectively reduce the phase angle on the open Prairie Island-Byron 345kV line. The NSP Operators were attempting to reduce the large phase angle with LLR requests and local generation reductions at Prairie Island (a 63 MW reduction between 01:13 CDT and 02:17 CDT). These actions were not effective in reducing the phase angle by the 1-2 degrees needed to allow the line to be reclosed.

The currently approved TCEX Operating Guide limits allow flows that exceed the post-contingent phase angle reclose limits on the Prairie Island-Byron 345kV line, and the King-Eau Claire-Arpin 345kV line. Therefore, whenever these lines trip at high TCEX conditions system readjustments will be required to allow reclosure.

## **2.3 Line tripping/Islanding which occurred during disturbance**

### **2.3.1 The formation of the islands occurred as expected from historic studies, but islands did not have good load/generation balance, and the North Dakota island was not cleanly formed**

The initial MAPP Minnesota/Manitoba/North Dakota/Saskatchewan island which formed during the disturbance occurred as expected. The transmission lines which tripped, were in the general vicinity of the region expected to open for an out-of-step condition between northern and southern MAPP. The Northwestern OH system islanding, due to the power surges from MAPP, would also be expected for this disturbance.

The subsequent separation of North Dakota from the eastern portion of the MAPP Minnesota/Manitoba/North Dakota/Saskatchewan island was initiated by loss of the CU HVDC line from a protection operation. The trip of the DC line resulted in a sudden increase in power on the AC system. The tripping of one Coal Creek Station unit immediately after the pole tripped was not enough to mitigate the DC line loss. The power surge caused tripping of the east-west ties between the North Dakota area and Minnesota, which separated the two systems.

The North Dakota island did not cleanly form, and the North Dakota system slipped against the Minnesota area at approximately 1.5 Hz, until the remaining Grant County-Douglas County 115kV tie line between the two areas tripped due to a fault. The slipping occurred for approximately 5 minutes (from 02:26 CDT to 02:31 CDT) across this asynchronous connection, and was observable in the voltages throughout the MAPP system. This remaining tie line, and the other line



sections further west and east of this line, did not trip due to out-of-step blocking on the distance relays. The Grant County-Douglas County 115kV line has been identified as the line which should be tripped during an out-of-step condition from historic studies, but was not enabled to trip for this condition.

There was no reported equipment damage to the terminals that tripped during any of the islanding. As noted in Section 5.2.3, there was damage to an out of service wave trap at the Douglas County substation, but the cause may not be related to this disturbance.

The islanding which occurred was due to normal distance protection tripping at the locus of the out-of-step condition between the regions. The islanding was not forced, and there was no coordinated out-of-step protective scheme in place to open the system at pre-determined locations. There is out-of-step blocking on a number of transmission lines between North and South Dakota to prevent multiple lines and lines with inadequately rated terminal facilities from tripping during an out-of-step swing.

Based on the lightly loaded early morning system conditions at the time of the disturbance, the northern MAPP area had a significant amount of excess generation on-line, which was being exported into southern MAPP and beyond MAPP. Therefore, when the disturbance occurred, the northern MAPP islands had a significant amount of excess generation on-line compared to the load in the islands, as evidenced by the extremely high frequency in those islands.

The Northwestern Ontario system, prior to the disturbance, was importing about 370 MW across the Manitoba, Minnesota, and eastern OH tie lines to support the area load. The NW Ontario island was generation deficient. As a result it suffered an excessive drop in the voltage and frequency prior to the total area collapse.

7 ( The generation unit tripping in the high frequency northern MAPP islands was primarily due to over-frequency protection, or due to governor action based on the exceedingly high frequency. Fortunately, the sequence of unit tripping, and apparent band of protective settings on the units in northern MAPP, prevented an excessive amount of generation from tripping and avoided a possible blackout in these islands. No formal studies have been performed to evaluate the coordination of the generation protection in the northern MAPP areas.

There was a significant decrease in MH HVDC power during the timeframe from the beginning of the disturbance, through initial island formation, until before the split of the initial Minnesota/Manitoba/North Dakota/Saskatchewan island into two parts. This reduction was approximately 1200 MW, which certainly contributed to limiting the over-frequency in the initial island. The reduction in DC power included automatic DC reductions following the Kenora-Whiteshell 230kV #1 line (K21W) trip and from the Forbes DCAR relay, and further local DC

reduction due to trip of Bipole 2 Valve groups 31 and 42 by over-frequency protection.

Immediately following the islanding of North Dakota, a large amplitude low frequency oscillation occurred in the North Dakota island. The dynamic system monitor at the Square Butte Center converter station (ND island) recorded an average value of 61.47 Hz with an oscillation frequency of 0.15 Hz for this event. The peak value of the oscillation reached 61.9 Hz. The oscillation was sustained and lasted for 30 seconds. At this time, both the cause and mitigating event are unknown. (See details in Figure #16)

### **2.3.2 The protective line tripping was correct during the disturbance; however, some of the line tripping/non-tripping was undesirable**

The line tripping which occurred during the disturbance was correct. No relay mis-operations occurred.

However, some of the line tripping which occurred during the disturbance was undesirable. For example, the Raun-Ft Calhoun 345kV line in eastern Nebraska and the Raun-Lakefield 345kV line in northwestern Iowa tripped near the same time as the Wilmarth-Lakefield 345kV line tripped on the out-of-step condition. These two line trips in Iowa and Nebraska were undesirable, and appear to have tripped on the out-of-step swing along with the Wilmarth-Lakefield 345kV line. There is no out-of-step blocking on these southern 345kV lines. The Neal unit tripping (1012 MW total), which occurred in the southern MAPP system that remained connected to the Eastern Interconnection, may have been avoided if these additional 345kV line trips had not occurred.

Also, as described in 2.3.1 above, the non-tripping of the Grant County-Douglas County 115kV line for the out-of-step condition between North Dakota and Minnesota was undesirable, and resulted in approximately 5 minutes of slipping between the two asynchronous regions.

The operation of the Forbes DCAR relay, which initiated a 340 MW MH DC reduction, was "as designed but not as intended". The design did not anticipate operation of the relay for the unusual condition that occurred. Operation for similar local conditions at Forbes, but for different system circumstances, would likely be undesirable.

### **2.3.3 The tripping of the HVDC lines between North Dakota and Minnesota was undesirable**

One or both poles of the two HVDC bipole lines between North Dakota and Minnesota were lost during the disturbance.

Both poles of the CU DC line were lost. CU DC Pole 1 was tripped manually by the UPA Operator at 02:25:14 CDT due to high loading and oscillations observed. The UPA Operator saw an increase in the bipole loading (due to the supplemental control response to the high island frequency), but did not fully understand why this occurred at the time. Continuing alarms associated with the disturbance at the Coal Creek RTU (at the rectifier end in North Dakota) also prevented any control actions there, so the supplemental damping controls could not be disabled. Prior loading of both Poles was 540 MW (where normal pole loading is 500 MW). CU DC Pole 2 then tripped properly on voltage stress protection at 02:25:42 CDT. The tripping of the bipole caused the separation of North Dakota from the Minnesota/Manitoba/Saskatchewan area due to the power surge on the parallel AC transmission lines between North Dakota and Minnesota. As seen in Figure #24, the tie lines between North Dakota and Minnesota were not significantly loaded prior to the trip of the CU DC line. Only one of the two Coal Creek Station units was tripped for the bipole trip, due to the unit tripping armed prior to the disturbance. The impact of the DC tripping on the Minnesota frequency is shown in Figure #11.

The Square Butte DC Pole 2 tripped on overfrequency protection at 02:25:44 CDT, when the North Dakota island frequency reached 62.2 Hz. This trip did not contribute to the North Dakota separation as it occurred after the islanding and was due to the overfrequency condition caused by the separation. The prior loading of the pole was 125 MW. Since the remaining pole ramped immediately to 250MW, which was the initial bipolar loading, the North Dakota island load-generation balance was not affected by the trip. There were no problems encountered with the Square Butte supplemental damping controls as they were disabled at the time of the disturbance.

#### **2.3.4 Automatic Generation Controls (AGC) were disabled during islanding**

The affected Control Area Operators correctly disabled AGC on a temporary basis during the islanding.

For the WAPA (Upper Great Plains Region) Control Area, which was split across the island boundaries, AGC was suspended at 02:10 CDT by automatic action based on the frequency deviation. WAPA Operators attempted to resume AGC at 02:23 CDT on Tie Line Bias, but this was unsuccessful. Control was switched to constant frequency at 02:59 CDT and back to Tie Line Bias at 03:06 CDT following the restoration of the North Dakota system to the Eastern Interconnection. The Oahe plant was placed back on normal AGC control at 03:17 CDT.

The Otter Tail Power Company (OTP) Control Area was within the North Dakota island and lost all three units capable of AGC by 02:26 CDT. The regulation service dynamic schedule with Manitoba Hydro was turned off at 02:30:11 CDT

because the OTP control area was separated from the MH control area at 02:25:42 CDT and remained off until 02:50:47 CDT. However, the tie line between the control areas was not returned to service until 03:25 CDT when the Letellier-Drayton 230kV line was energized. Thus, the OTP control area lost their AGC capability during the islanding. Also, the regulation service dynamic schedule was restored prior to the North Dakota island being resynchronized with the Eastern Interconnection.

For the United Power Association (UPA) Control Area, AGC tripped off-line at about 02:22 CDT due to sudden frequency deviation. AGC was returned to normal later in the morning when the system was restored.

For the Northern States Power Company (NSP) Control Area, Sherco units #1, #2, and #3 were on AGC prior to the disturbance. After Sherco #3 tripped at 02:25 CDT, the NSP Plant Operators switched Sherco units #1 and #2 into manual control mode, effectively disabling the AGC.

The Manitoba Hydro (MH) System Control Centre (SCC) tripped off AGC at 02:26 CDT due to the disturbance, and returned AGC to normal at 02:41 CDT.

### **2.3.5 The MAPP Security Center Operator (SCO) and MAPP Member Operators were not sufficiently aware of the system conditions or scope of the islanding**

There was insufficient transmission line status and frequency metering available at the MAPP Security Center (SC) for the MAPP SCO to determine the status of the MAPP system during the disturbance. The single frequency meter available at the MAPP SC failed to indicate the proper local Twin Cities frequency during the disturbance. The MAPP SCO did not have adequate information to advise Member Operators regarding the system islanding. This lack of a full picture of the MAPP system conditions also prevented the MAPP SCO from being able to advise Members Operators regarding whether they should attempt to supply MAPP Emergency Energy Replacement (EM) schedules which were requested by Members that lost generation while the system was still separated. The WAPA MCN broadcast at 02:32 CDT appears to have been the first indication to many Member Operators that the system was islanded.

The Member Operators have indicated they were busy addressing issues in their local systems. There was very little communication between the MAPP Member Operators, and few replies to requests for information by Member Operators, over the MAPP Communications Network (MCN) during the disturbance.

### **2.3.6 The MAPP MCN functioned well during disturbance, but was not utilized effectively**

The MAPP Security Center Operator (SCO) and MAPP Member Operators have indicated that the MAPP Communications Network (MCN) functioned well during the disturbance, especially based on the large volume of data (primarily related to MAPP EM calls).

However, the MCN was not utilized by MAPP Member Operators as effectively as it could have been. Several MAPP Member Operators requested information from all the other Operators to help determine the conditions of the system, but did not receive replies. The large volume of information on the MCN (primarily EM Requests) may have made it difficult to review all the messages.

### **2.3.7 Response of Generating Units to High Island Frequency**

Very little data is available on generating unit performance while operating islanded. Looking at the frequency chart in Figure #5 for the Minnesota/-Manitoba/North Dakota/Saskatchewan island that formed at 02:21 CDT, it can be seen that, after an initial overshoot, frequency went to about 60.75 Hz. At that point frequency started to increase and over the next 2 ½ minutes there was a steady ramp to about 61 Hz. The trip of the Sherco 3 unit caused the frequency to stabilize at about 60.8 Hz.

After forming at 02:25 CDT, the North Dakota island operated for about 40 minutes before being resynchronized to the Eastern Interconnection. This island had a greater relative unbalance between generation and load, and stabilized at a frequency of about 61.3 Hz, higher than the initial island. Based on what data is available and the island frequency charts, it appears most generating plant turbine governors properly reduced output in response to the conditions that resulted when the island formed with excess generation. As shown in Figure #5, frequency was very stable in the North Dakota island for the thirty-minute period from initial formation until Operators began reducing frequency. This indicates that the units that survived the initial disturbances were quick to stabilize at an island frequency approximately two percent higher than normal. One unit that reported questionable performance was Young 2, which initially reduced but then rapidly returned to its pre-disturbance generating level.

The systems reported no specific Operator actions taken to reduce the extremely high frequency of about 61.3 Hz in the North Dakota island during the first 30 minutes after the island was formed. This sustained high frequency caused the units in the island to operate in an overspeed condition for an extended period of time. Operation in these conditions can result in damage or loss of life to steam unit turbines. No specific damage was reported by the systems. However, several systems are still evaluating the impacts of the high frequency operation and possible loss of life to their steam turbine units.

## **2.4 System Restoration**

#### **2.4.1 The system restoration was delayed due to lack of knowledge of system conditions, but overall was accomplished well by the Operators**

MAPP Member Operators have indicated that they delayed restoration of certain tie lines and generation units based on a lack of sufficient information about the current MAPP system conditions. Improved communications between Operators in the islands would have facilitated quicker restoration of the system.

However, the overall system restoration both in the MAPP area and the NW Ontario area was accomplished with very few problems based on the severity of the disturbance and the number of transmission and generation facilities that tripped.

#### **2.4.2 The automatic reclosing on the lines in Wisconsin/Minnesota assisted the restoration**

The Ironwood-Park Falls 115kV line reclosed at 02:25:59 CDT, approximately 12 seconds after the North Dakota area separated from the Minnesota, Manitoba, and Saskatchewan area. This line had tripped approximately 4-1/2 minutes earlier and the automatic recloser closed the line once it was synchronized. This automatic line closure reconnected the Minnesota, Manitoba, and Saskatchewan island to the Eastern Interconnection. The remaining open lines between Minnesota and the Eastern Interconnection then quickly reclosed automatically. This automatic reclosing significantly shortened the duration of the Minnesota, Manitoba, and Saskatchewan island separation.

#### **2.4.3 MAPP Security Center Operator (SCO) Request for Time Error Correction during disturbance**

The MAPP SCO requested a Time Correction at 02:38 CDT to attempt to arrest the frequency decline observed on the system. The time error (TE) at the time was -4.65 seconds, so the request was acceptable in that respect. The time error was implemented in the Eastern Interconnection at 03:00 CDT, and terminated at 04:00 CDT. The frequency of the Eastern Interconnection improved after the time correction was implemented, and the North Dakota island was able to be restored at 03:03 CDT.

The MAPP SCO has indicated that he did check with NERC to verify there were no system problems outside of MAPP prior to calling for a Time Correction.

The frequency of the Eastern Interconnection was low (approximately 59.95 Hz) during the disturbance due to the loss of a significant amount of generation in MAPP and the separation of northern MAPP. The control areas that were deficit

of generation due to unit tripping or loss of schedules from northern MAPP did not implement load shedding to restore the system frequency.

#### **2.4.4 OH experienced high voltages during restoration of NW Ontario system**

Ontario Hydro experienced high voltages on the NW Ontario transmission system as it was restoring the system from black out conditions. To control the voltage it was necessary to coordinate load and transmission restoration.

#### **2.4.5 SCADA sync scope capability was effectively used to reconnect the North Dakota island**

The North Dakota island was reconnected to the Eastern Interconnection at 03:03:39 CDT when WAPA closed the Bismarck-Glenham 230kV line using their automatic Synchro-Check System. This system automatically compares the voltage magnitude, voltage difference, phase angle, and phase angle rate of change across an open breaker prior to closing. If all of these values are within limits, breaker closure is accomplished. If the limits are exceeded, the WAPA Dispatcher is provided with a dynamic display of the incoming and running voltages and phase angle, via the SCADA system. Manual voltage and generation adjustments can then be performed until the values are within limits. This capability allowed the WAPA Dispatcher to restore the line remotely via SCADA.

### **2.5 SCADA/Metering/Communications operation during disturbance**

#### **2.5.1 Several MAPP Members and Ontario Hydro had SCADA, Metering, and/or RTU problems during the disturbance**

Several MAPP Members experienced SCADA problems during and following the disturbance. Otter Tail Power Company (OTP) indicated that their system lost data such as alarms and messages. The United Power Association (UPA) System Operator experienced difficulty in completing control actions at a critical substation when the disturbance caused several points to continuously cycle in and out of alarm. Dairyland Power Cooperative (DPC) indicated that their Apple River RTU communications failed during the disturbance. Omaha Public Power District's (OPPD) EMS system, due to prioritization of tasks during the heavy alarm/event loading, failed to record frequency data from 02:22 to 02:23:30 CDT. MEC lost SCADA data due to the large number of alarms that occurred. Ontario Hydro also indicated that their system lost some data.

The disturbance caused a significant amount of data to be processed by the SCADA systems. WAPA indicated that their SCADA system recorded

approximately 10,000 events, alarms, status changes, and telemetered limit excursions during the disturbance.

Due to the very high frequency in the islands ( $> 61$  Hz), it was discovered that the OTP, UPA, and MAPP Security Center frequency meters/charts clipped and did not record the maximum frequency deviations. OTP's frequency meter clamped at 60.132 Hz due to a transducer limitation.

NSP reported that the Byron-Prairie Island 345kV line MW flow meter failed at the time of the Prairie Island-Byron 345kV line trip. As a result of this failure, the observed TCEX value was being manually determined from about 02:45 CDT on June 25th until June 27th at 19:17 CDT when the Byron-Adams 345kV line tripped due to storm damage to a number of structures. Once NSP Operators recognized the meter was not functioning properly at about 09:00 CDT on June 25th, the Operators manually entered the Byron-Adams 345 kV line flow as determined by the state estimator into the EMS system. The Operators also periodically checked the entered value with the state-estimated value. If the entered value was excessively off, the new state-estimated value was manually entered into the EMS system. The manually entered value was used to calculate TCEX.

The Byron RTU appears to have been operating properly. (Note: NSP has since reported that the meter has been subsequently repaired during the subsequent Byron-Adams 345kV line outage.)

### **2.5.2 Disturbance recorders performed adequately during disturbance, but several failed, and additional recorders are required**

The disturbance recorders performed adequately during the disturbance, providing sufficient information to evaluate the system response. However, a number of units failed to record the disturbance, and there are areas in MAPP where additional monitoring would be useful.

NSP has four dynamic event recorders on the system positioned at the following substations: Coal Creek, Prairie, Forbes, and King. Of the four recorders only the King recorder contained usable data. The Coal Creek, Prairie, and Forbes units experienced communications problems and the data was unavailable for retrieval. The King recorder captured the Wilmarth-Lakefield 345kV line trip as well as the frequency deviations in the area.

Minnesota Power has dynamic disturbance recorders at the Arrowhead, Center and Littlefork substations which all triggered at various times during the disturbance. Most of the significant portions of the disturbance were recorded. Contiguous recording at each of these locations would have been beneficial for post-disturbance analysis.



Ontario Hydro has indicated that they plan to install additional disturbance recorders in their system to better monitor the system performance during similar system disturbances in future.

### **2.5.3 The SCADA and disturbance recorder data time stamping varies in accuracy and is difficult to correlate**

The SCADA data available from the MAPP Member systems varied in time stamping from the nearest minute, to 4 second RTU scan rates, to GPS time synchronized. Substation equipment, including fault recorders, sequence of event recorders, and microprocessor relays, in MAPP often provide times to millisecond resolution. However, even if available, such data is not useful for system disturbance analysis unless the clocks in such equipment are synchronized to a time standard throughout the system so that events have a common time base. For the Sequence of Events compiled for this report, the timing of many events was based on less accurate sources such as SCADA logs. In cases when it was significant, reported times were adjusted so that events could be shown where they most likely occurred relative to other events.

The Minnesota Power dynamic system monitors which have accurate frequency transducers and GPS time synchronization were invaluable in analyzing this disturbance and identifying the correct sequence of events in many instances.

## **2.6 MAPP Emergency Energy Replacement Procedure (EM)**

### **2.6.1 Requests for MAPP EM exceeded the reserves in MAPP**

During the disturbance, there were eight concurrent requests for MAPP EM schedules due to the significant amount of generation lost. The total amount of energy replacement requested was 2215 MW, and exceeded the total required MAPP reserves of 1280 MW.

The volume of the EM requests, and the large number of schedule requests to the MAPP Member Operators was practically unmanageable. MAPP has indicated that it would have been beneficial if the MAPP SCO could have suspended the EM procedure when the magnitude of the EM requests became too large.

### **2.6.2 Requests for MAPP EM were made during the disturbance, and requested for units lost in the islands that had excessive generation on-line**

As outlined in Section 5.10, four of the EM requests were from Members which lost generation within the North Dakota island, while it was still separated from the rest of MAPP and the Eastern Interconnection. Even with these generation

losses the North Dakota island frequency at the time was greater than 61 Hz. The southern MAPP Members could not supply requested EM schedules across the separation until after 03:03 CDT.

The remaining four EM requests were from Members which lost generation in the southern/eastern MAPP areas that were still connected, or had been reconnected, to the Eastern Interconnection. Because of the separation, the MAPP Members within the North Dakota island could not deliver requested EM schedules until after 03:03 CDT.

The automatic MAPP EM procedure cannot be effectively implemented when the system is separated and the status of the system is unknown. However, the EM program was able to handle the large number of concurrent requests easily, and no problems occurred.

When the MAPP SCO determined for sure that the system separations in MAPP were restored, an MCN message was broadcast to all Members at 03:20 requesting them to respond to the EM requests in progress.

### **2.6.3 Several MAPP Members were not able to immediately supply EM schedules to requesting Members**

Several Operators contacted the MAPP Security Center Operator (SCO) to request information on the islanding, which was still unclear at the time the EM requests were broadcast. The WAPA Operators, seeing excessive frequencies already in the area, notified MAPP that they would not be able to supply reserves immediately. The NSP Operators also notified MAPP that they would not be able to supply reserves.

The MAPP Members that did not comply with the requested EM schedules due to the high frequency were justified in doing so. Generation increases should not be implemented in a high frequency island.

Several additional MAPP Members did not supply EM requests immediately due to generation losses, uncertainty about the system conditions, etc.

All of the MAPP Members were supplying required reserves by 04:00 CDT. There were several additional EM requests later in the day, due to the generation lost during the disturbance. All MAPP Members responded to these later requests.

### 3. RECOMMENDATIONS

#### 3.1 Operating Conditions at time of Disturbance

##### 3.1.1 Readjusting system back within Operating Guide limits must be given priority

The system must be operated within the MAPP approved Operating Guide limits. Following a system contingency, the system exports must be reduced, or other necessary adjustments made immediately to return the system within the Operating Guide limits. These re-adjustments should be done as soon as possible, and must be completed within the readjustment period allowed in the MAPP Operating Standards.

Re-establishing the system conditions within the Operating Guide limits must be given priority once the system conditions stabilize and critical emergencies are addressed.

When the Operating Guide limits are re-established and the system can again securely withstand the next contingency, then other system restorations should be considered.

##### 3.1.2 MAPP Security Center Operator (SCO) must assess security of transmission system

The MAPP Security Center Operator (SCO) must be aware of the presence of an Operating Security Limit Violation where the system conditions are outside of approved MAPP Operating Guides, and ensure actions are taken to return the system conditions within Operating Guide limits in the allowable time limits.

The MAPP Security Center (SC) must have applicable Operating Guides readily available for reference by the SCO, and have the necessary system information available to utilize the Operating Guides. An Operating Guide management system should be implemented. The MAPP SC should review the Operating Guides with the MAPP ORS, and appropriate ORS Working Groups, to ensure that the MAPP SC has up to date copies of all necessary Operating Guides, and that the Security Center Operators are familiar with these Guides.

The MAPP SC must obtain, or internally calculate, the adjusted TCEX limit, as calculated and used by the NSP Operators, so the SCO can determine precisely if the TCEX value is above Operating Guide limits at any time.

The MAPP Member Operators should notify MAPP immediately of an emergency condition where Operating Limits are exceeded, and apprise the MAPP SCO of the severity of the system conditions.

The MAPP SC should implement a dynamic security assessment tool to assess current system conditions and determine that adequate stability margins in northern MAPP and other applicable areas in MAPP exist at all times.

### **3.1.3 NSP must demonstrate the TCEX adjustment sensitivity for Prior Outage conditions**

NSP must complete the necessary studies to demonstrate whether the TCEX limit can be increased during prior outage conditions based on Sherco generation levels, and the local Twin Cities metro area generation pattern. The prior outage Operating Guides should be updated to reflect this sensitivity.

The studies and updated Operating Guides must be submitted to the MAPP NMORWG and ORS for approval prior to their use.

### **3.1.4 The MAPP Operating Standards and Design Standards should be reviewed**

The MAPP Operating Review Subcommittee (ORS) should review the Operating Standards definition for the Readjustment Period to ensure that it clearly specifies the allowable time period to restore the reliability of the system. The MAPP Design Standards allow permissible readjustments to restore the reliability of the system within 10 minutes.

The MAPP ORS and MAPP Design Review Subcommittee (DRS) should also jointly review the allowable time period to restore the reliability of the system against the new NERC Operating Policy 2 (Effective 7/1/98) which allows up to 30 minutes.<sup>11</sup>

### **3.1.5 The MAPP Operating Requirements should be reviewed**

The appropriate MAPP Committees should review and update the MAPP Operating Requirements.

## **3.2 Procedures utilized to return to a secure state**

### **3.2.1 NSP Operators should immediately reduce TCEX sufficiently to achieve Operating Guide limits**

<sup>11</sup> NERC Operating Manual, Policy 2, Standard 2 (January 5, 1998): "Following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes." This NERC Standard requires that the system be able to again securely withstand the next first contingency within 30 minutes at the latest after a contingency occurs. The NERC definition of OPERATING SECURITY LIMITS is: "OPERATING SECURITY LIMITS define the acceptable operating boundaries."

NSP should modify their internal Operating Guide implementation procedures (and associated Operating Guides) to indicate that the amount of TCEX reduction which should be requested (or implemented) is the larger of the typical 50 MW increment OR the absolute amount of negative "Net Export Margin". The "Net Export Margin" is defined as the TCEX limit less the Actual TCEX value.

Whenever the TCEX flow is above the Operating Guide limit, the export should be reduced as quickly as possible by the amount that the export is above the limit regardless of the procedures used.

**3.2.2 MAPP Line Loading Relief (LLR) Procedure, in its current state, should not be relied upon for relief during emergency conditions where the system is in an insecure state**

Operating Guides which must be implemented under emergency conditions (e.g. following a line trip) should be reviewed and updated as soon as possible to outline procedures to quickly reduce export or loading conditions without utilizing the current MAPP LLR procedure. The current MAPP LLR procedure should not be relied upon for relief during emergency conditions, as it cannot be implemented effectively and within the required timeframes in many cases.

Operating Guides that address emergency conditions, such as line trips, should identify permissible system readjustments, outlined in the MAPP Operating Standards, that can achieve the necessary system changes within the allowable readjustment period. These permissible readjustments include: generation rejection, generation reductions, reduction of economy exports to the extent possible within the readjustment period, adjustment of Load Tap Changing (LTC) transformers, phase shifters, or HVDC flows.

MAPP members should take whatever steps are necessary to return to a secure operating state. Local action (reducing generation or cutting all allowable tariff schedules) should be taken immediately whenever Operating Guidelines are being violated. The violation of operating guidelines should be considered as an emergency state (stability limit exceeded) thus requiring local actions, including curtailing all contributing transmission service commitments as allowed by the MAPP Operating Standards. Calling for Line Loading Relief is not an appropriate response to the violation of Operating Guidelines, where the system is in an insecure state, and should be used only to prevent entering such a condition. Each control area must pre-determine the control action required to coordinate its efforts with the MAPP Security Center to return to a secure operating state immediately.

The Operating Guides that rely on MAPP LLR as the primary procedure for reducing line loading or export levels, should identify other procedures to ensure the necessary relief can be achieved in the event that LLR cannot be effectively utilized.

The MAPP LLR Working Group (LLRWG) should review the current LLR procedure, and recommend/implement improvements to allow its use under emergency conditions, if the MAPP Members desire to utilize it in the future as a system readjustment procedure for emergency condition Operating Guides.

The MAPP Members should implement requested LLR schedule curtailments as soon as possible, and within the timeframe requested by the MAPP SCO. Members and other parties should not delay implementing schedule curtailments by contacting the MAPP SCO before making the schedule cuts, unless there are obvious errors in the requested schedule curtailments. The MAPP LLRWG should modify and clarify the LLR procedure implementation to allow the MAPP SCO to request immediate schedule curtailments for emergency conditions.

**3.2.3 MAPP Line Loading Relief (LLR) Procedure software should be improved to prevent inadvertent schedule curtailment requests on an open transmission line/facility**

The MAPP Center, in coordination with the MAPP LLRWG, should implement improvements in the LLR software to warn the SCO if the facility for which LLR is being evaluated is already open in the LLR powerflow model. The LLR software should not execute in this case and should not post requests for schedule curtailments, which identify no schedules to be curtailed. (Note: The MAPP Center staff has implemented this recommended software correction.)

MAPP Member Operators and other parties requesting MAPP LLR should not request LLR on a facility that is out of service (e.g. a transmission line that is open and cannot be reclosed due to large phase angle across the open line). If MAPP LLR is requested, a different facility (that will provide the required relief on the desired facility) should be utilized in the LLR request.

The MAPP LLRWG should review the appropriateness of utilizing LLR to reduce the phase angle on open transmission facilities.

**3.2.4 Formal Operating Guides should be developed for reduction of high phase angle across open Prairie Island-Byron 345kV line, and other major transmission lines in MAPP**

NSP and other MAPP Members with transmission lines that can develop high phase angles across the open line, preventing reclosure, should develop formal Operating Guides to identify effective and rapid procedures to reduce the phase angle.

In the case of the Twin Cities export lines, actions such as MH DC reductions and phase shifter adjustments in the area should be evaluated.

These phase angle reduction Guides and supporting studies should be submitted to the MAPP ORS and the appropriate ORS Working Group(s) for review and approval.

The MAPP Members should consider developing and observing "Storm Condition" Operating Limits during periods of severe storms. These limits could be based on the circuit automatic or manual permissible reclosure angles in the affected area.

### **3.2.5 Phase Angle Limit Calculations**

In addition, NSP and other MAPP Members should review the phase angle limit settings on major transmission lines that can develop high phase angles across the open line, and ensure that the settings are not overly conservative. In the case where generating unit shaft torque is the limiting factor, detailed studies of the specific shaft system may be warranted. The MAPP systems should review the policies related to transient torque limits applied during critical system emergencies. Specifically, NSP should increase the manual re-close setting at the Byron Substation for the Prairie Island-Byron 345kV line, if possible. MAPP should seriously consider bypassing synchrocheck relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.

### **3.3 Line tripping/Islanding which occurred during disturbance**

#### **3.3.1 The load/generation imbalance in the islands should be evaluated**

The MAPP NMORWG should review the islanding which occurred in MAPP during the disturbance. Specifically, NMORWG should evaluate the locations that the islands formed, and the imbalance between the generation and load isolated within each island. NMORWG should identify further recommendations regarding the need for controlled islanding, or whether Operating Guide changes are required to address the significant generation/load unbalance within the islands.

In addition, the NMORWG should review the coordination of generation over-frequency protection in the northern MAPP area.

#### **3.3.2 The undesirable protective line tripping/non-tripping which occurred during the disturbance should be reviewed and corrected**

MidAmerican Electric Company (MEC) and Alliant-IPW should review the protection settings, coordination, and out-of-step blocking philosophy on the Raun-Ft Calhoun 345kV line in eastern Nebraska and the Raun-Lakefield 345kV line in northwestern Iowa. The protection should be coordinated with the Wilmarth-Lakefield 345kV line to prevent unnecessary tripping during an out-of-step condition in the Twin Cities.

OTP and NSP should review the application of out-of-step blocking on the Grant County-Douglas County 115kV line, and the other lines in the immediate area, to determine the appropriate location to allow tripping for out-of-step conditions between North Dakota and Minnesota. This effort should be coordinated with the NMORWG overall review of the islanding (in Recommendation 3.3.1).

MH and MP should review the Forbes DCAR relay settings and revise as necessary to prevent undesired MH DC reductions for the conditions that occurred during this disturbance.

### **3.3.3 The MAPP Security Center Operator (SCO) must have a better overall picture of the MAPP system conditions and scope of islanding**

The MAPP Security Center (SC) must have real time, or near-real time frequency metering from several geographic locations around the MAPP system, so the MAPP SCO can determine whether any island conditions exist, and the rough scope of the islanding. (Note: Additional frequency meters will be available in the new MAPP building fulfilling this recommendation in part. In the interim, the MAPP SC should replace the existing frequency meter, which is defective, as soon as possible.)

The MAPP SC also needs to incorporate an alarming function and clearly display the status changes of critical transmission facilities in the MAPP area, so the SCO can quickly determine the actual status of the overall MAPP system.

The MAPP SC staff should also internally review the adequacy of the information that is available to the SCO and determine whether it is sufficient. The MAPP SCO must be able to properly assess the MAPP transmission security at all times and effectively coordinate emergency operations in the MAPP region, as required in the NERC Operating Requirements.

The MAPP Member Operators must provide system status information to the MAPP SC, as required by the MAPP Operating Requirements. At a minimum, the Member Operators must provide indication over the MCN when their system is in an emergency condition, and when it is restored to a normal condition.



### **3.3.4 The tripping of the HVDC lines between North Dakota and Minnesota when North Dakota islands should be prevented during future disturbances**

The over-frequency protection strategy at the Square Butte terminal of the Square Butte DC line should be reviewed to determine if new settings could be applied to prevent similar tripping during similar conditions.

UPA should develop an improved procedure and Operator training for operation of the CU DC line when the North Dakota AC system is islanded to prevent tripping of the CU DC line during similar conditions.

UPA should also review the coordination between the local North Dakota frequency contribution to the delta frequency (North Dakota/Minnesota) based damping control on the CU HVDC line.

### **3.3.5 Automatic Generation Controls (AGC) should be disabled during islanding**

Once the MAPP Members recognize that the network has separated into islands, such that generators under AGC control are electrically separated from the area where the control area ACE is calculated, AGC should be temporarily turned off as outlined in the MAPP Operating Requirements (Section 19.A.5).

The control areas in each island should operate in the Flat Frequency mode, controlling only units within the island that contains the AGC frequency source, and make other adjustments, as required, to immediately restore the frequency to normal as required by the NERC Operating Policies and to minimize steam unit turbine loss of life during sustained operation in an overspeed condition.

Control areas involved in dynamic schedules for regulation service should turn off the dynamic schedule when the associated transmission is open. Control area operators should evaluate whether continued use of AGC could endanger system reliability when the frequency deviation exceeds 200 mHz. AGC may be suspended if reliability is endangered.

## **3.4 System Restoration**

### **3.4.1 The MAPP Member Operators need critical information earlier from the MAPP Security Center and other Member Operators**

The MAPP Member Operators need to be able to get critical information from the MAPP Security Center Operator (SCO) and other Member Operators earlier during a disturbance, to assist them in responding to the emergency.

The MAPP Security Center (SC) staff should further review the use of the MAPP Communications Network (MCN) during the disturbance, identify reasons that the MCN was not utilized as effectively as it could have been, and formulate additional recommendations to improve the use and benefits of the MCN for future disturbances or emergency conditions.

#### **3.4.2 Automatic reclosing**

The MAPP Members should assess the feasibility of operating critical interfaces within permissible "high speed" reclosure angle during the "high risk" conditions such as during Summer thunderstorms.

#### **3.4.3 MAPP Security Center Operator (SCO) Request for Time Error Correction during disturbance**

Time Error Correction should not be used as an emergency tool to correct regional frequency problems. Control area Operators should take other MAPP and NERC recommended actions to address low frequency conditions.

#### **3.4.4 OH experienced high voltages during restoration of NW Ontario system**

Ontario Hydro should review their system restoration plan for Northwestern Ontario to ensure acceptable system voltages during the restoration.

#### **3.4.5 Phase Angle data should be available via SCADA**

The MAPP Member systems should consider making phase angle data available to their Operators, via the SCADA systems, for critical transmission lines.

### **3.5 SCADA/Metering/Communications operation during disturbance**

#### **3.5.1 SCADA, Metering, and/or RTU problems observed during the disturbance should be corrected**

The following MAPP Members should review the problems which occurred with their SCADA/EMS systems and report on actions taken to correct the problems: MidAmerican Energy Company (MEC), Omaha Public Power District (OPPD), Otter Tail Power Company (OTP), and United Power Association (UPA).

Ontario Hydro should review the SCADA problems they experienced during the disturbance, and make necessary corrections.

The systems should review the capability of their SCADA/EMS to log critical analog data (e.g. generating unit MW, MVAR, and kV) during a system disturbance.

Otter Tail Power Company (OTP) should replace their defective frequency transducers, and add more frequency displays in their Control Center measuring the frequency in various locations in the OTP system to provide a means to recognize islanding in the OTP system.

United Power Association (UPA) should replace the defective frequency transducer in the UPA Control Center. UPA should also correct the problems with the Coal Creek RTU.

The MAPP Security Center should replace the defective frequency meter in the Security Center as also outlined in Recommendation 3.3.3 above.

NSP should review the Byron Substation RTU performance and correct any problems. DPC should review the Apple River RTU communications and correct any problems.

### **3.5.2 Disturbance Recorders**

The systems that own disturbance recorders should review the performance of their equipment during the disturbance, and correct any operational problems that occurred. The systems should also review and adjust the triggering algorithms on these devices, if necessary, to assure complete recordings and reliable triggering for future events.

The MAPP Members should work together to identify additional locations for disturbance recorders, and install a more complete network of monitoring systems. The procedures for requesting triggering of the recorders throughout the MAPP system should be developed. The MAPP Security Center should have a procedure for triggering the MAPP Members' disturbance recorders when a significant disturbance occurs.

### **3.5.3 Need better time stamping for SCADA and Disturbance Recorder data**

The systems should consider better time resolution for operation of critical breakers. This can be achieved through use of sequence of events recorders, fault recorders, or SCADA RTU's with sequence of events capability. Time synchronization using GPS receivers or similar hardware should be provided.

### **3.6 MAPP Emergency Energy Replacement Procedure (EM)**

#### **3.6.1 MAPP Security Center Operator (SCO) must have additional information and ability to manage EM calls during disturbances**

As previously outlined in Recommendation 3.3.3, the MAPP SCO needs additional system information in order to manage coordinated procedures such as the EM procedure between the MAPP Members. The MAPP SCO must be able to provide feedback on the overall system conditions, and recommend to the Members how they should respond to automatic coordinated procedures during disturbances.

The MAPP SCO needs the ability to properly manage the EM procedure during disturbances. This should include authorization to suspend its automatic execution, if necessary, in the event that system conditions prevent it from being implemented properly, or if the EM schedule requests will negatively impact the system during emergency conditions. The MAPP Security Center, and appropriate MAPP Committees, should review this recommendation and the EM procedure performance during the June 25<sup>th</sup> disturbance, and formulate any additional recommendations. Specifically, this group should determine whether the automatic EM procedure should automatically be suspended if the amount of EM requested within a certain timeframe is too large (for example, greater than the MAPP Operating Reserve Requirement).

#### **3.6.2 MAPP Member systems must comply with EM obligations, and review system conditions prior to submitting EM requests**

MAPP Members must immediately respond to requests to provide reserves, unless the system conditions prevent the Member from responding to EM requests. In the event that a Member cannot immediately respond to an EM request, the Member should notify the MAPP Security Center Operator (SCO) as soon as possible.

The MAPP Member Operators should also review system conditions prior to requesting EM schedule requests for a unit loss. In the case where the system is separated, and islands are present, the Operators should determine whether the EM request will negatively impact the system conditions, and whether the other MAPP Members will even be able to supply the request. The MAPP Security Center, and appropriate MAPP Committees, should review the 2 minute initiation requirement of the MAPP EM procedure, specifically regarding whether this requirement allows the Operators to properly review the system conditions during an emergency prior to making the EM request for a generating unit loss.

### **3.7 NERC Operating Policy/MAPP Operating Standards Violations**

### **3.7.1 Systems should review NERC Operating Policies violated during disturbance and take corrective action**

Based upon the NERC Operating Policies that were violated during the disturbance, as outlined in this report, the MAPP Member systems should review these Policy violations and take corrective action. Specifically, NERC Operating Policies 1, 2, and 5 should be reviewed.

### **3.7.2 Systems should review MAPP Operating Standards and Operating Requirements violated during disturbance and take corrective action**

The MAPP Member systems should review the MAPP Operating Standards and MAPP Operating Requirements to ensure compliance. Corrective actions should be taken to address the violations outlined in this report.

## **3.8 Other Recommendations**

### **3.8.1 Otter Tail Power Company Control Center Backup Power**

The OTP Control Center lost power during the disturbance. The UPS picked-up, but the back-up generator failed to pick-up the control center. It appears that system voltage oscillations caused the back-up generator control scheme to function incorrectly. OTP should review the back-up generator wiring and test the unit.

The OTP Control Center area was dimly lit when the emergency lighting was on. OTP should add additional emergency lighting fixtures in the Control Center to provide adequate lighting conditions.

### **3.8.2 MAPP Member systems should review generator response during high frequency islanding**

The MAPP Member systems should review the response of all generators in the islands, especially in the extremely high frequency North Dakota island, and determine if the generator response was acceptable.

Based on the reported response of the Young 2 unit, its boiler and turbine controls should be reviewed to determine if they are properly set and coordinated.

#### **4. PRIOR OUTAGE CONDITIONS**

##### **4.1 Generation Off-line and Out-of-Service:**

None of the unit outages affected the reliability or transfer capabilities in MAPP or Northwestern Ontario systems. The total net generating capability off-line, in the islands that formed during the disturbance and in the MAPP systems that remained tied to the Eastern Interconnection, is shown below.

- Minnesota/Manitoba/Saskatchewan Island: 3,811 MW
- North Dakota Island: 281 MW
- NW Ontario Hydro Island: 980 MW
- Southern/Eastern MAPP: 2,024 MW

A summary of the individual generating units, which were off-line prior to the disturbance, is included in Appendix #3.

##### **4.2 Generation On-line:**

Generation in the MAPP region and the Northwestern Ontario area was normal prior to the Disturbance. The total net output (at about 02:17 CDT) of all the generating units, in the islands formed during the disturbance and in the MAPP systems that remained tied to the Eastern Interconnection, is shown below.

- Minnesota/Manitoba/Saskatchewan Island: 11,852 MW
- North Dakota Island: 2,810 MW
- NW Ontario Hydro Island: 270 MW
- Southern/Eastern MAPP: 7,641 MW

A summary of the individual on-line generating units net MW output prior to the disturbance is included in Appendix #3.

##### **4.3 Transmission out of Service:**

In the early morning of 6/25/98, no major transmission facilities were out of service for maintenance or other purposes that would impact reliability or regional transfer capabilities. The transmission facilities that were out of service were as follows:

###### Minnesota

Lake Marion-West Faribault 115kV

Carver County-Glendale-Scott County 115kV

Elm Creek-West Coon Rapids 115kV

###### North Dakota/South Dakota

Bristol-Summit 115kV  
Brookings-White 115kV  
Oahe-Eagle Butte 115kV

Nebraska

Tekamah-Raun 161kV  
Stockville-Red Willow 115kV  
Kearney-Lowell 115kV

Iowa

Avoca-Atlantic 161kV  
Neal-Monona 161kV  
Fox-Lake 161/69kV transformer #1  
Fox Lake-Serburn 69kV  
Marshalltown-Eldora 115kV  
Wellsburg 115/69kV transformer

Manitoba/NW Ontario

Whiteshell-Kenora 230kV #2 (K22W)

However, just prior to the disturbance, one of the major 345kV lines out of the Twin Cities tripped, and a 161kV line was damaged, due to the severe storm going through the Twin Cities and western Wisconsin areas. These were as follows:

Prairie Island-Byron 345kV (Tripped @ 01:34 CDT)  
Alma-Rock Elm 161kV (Tripped @ 02:01 CDT)

**4.4 Interchange Summary, Significant Pre-disturbance Flows:**

The export conditions and other significant flows at approximately 02:15 CDT, prior to the disturbance (but after the earlier trip of the Prairie Island-Byron 345kV line at 01:34 CDT), were as follows:

Northern MAPP

North Dakota Export (NDEX) = 1297 MW  
Twin Cities Export (TCEX) = 1004 MW<sup>12</sup>  
Manitoba Hydro Export (MHEX) = 1253 MW (From MH to USA)

CU DC Bipole Loading = 810 MW (From ND to MN)  
(Coal Creek Station Generation = 840 MW, Amount on AC = 20 MW<sup>13</sup>)

Square Butte DC Bipole Loading = 295 MW (From ND to MN)  
(Young #2 Generation = 409 MW; Amount on AC = 115 MW<sup>14</sup>)

<sup>12</sup> Above Operating Guide Limit due to prior outage of Prairie Island-Byron 345kV line at 01:34 CDT.

<sup>13</sup> The 10MW difference is due to losses and DC auxiliary load.

Miles City DC Loading = 110 MW West-to-East (From WSCC to MAPP)

Tioga-Boundary Dam 230kV (B10T) Flow = 24 MW (From USA to SPC)

Byron-Adams 345kV Flow = 51 MW

Wilmarth-Lakefield 345kV Flow = 178 MW

Eau Claire-Arpin 345kV Flow = 775 MW

King-Eau Claire 345kV Flow = 1048 MW

Dorsey-Forbes 500kV (D602F) Flow = 909 MW (From MH to USA)

Letellier-Drayton 230kV (L20D) Flow = 171 MW (From MH to USA)

Richer-Moranville 230kV Flow = 173 MW (From MH to USA)

Saskatchewan:

Saskatchewan-Manitoba Import = 232 MW (From MH to SPC)

Saskatchewan-BEPC Import = 24 MW (From BEPC to SPC)

Saskatchewan-Alberta Import = 75 MW (From Alberta to SPC)

Northwestern Ontario

Whiteshell-Kenora 230kV (K21W) Flow = 120 MW (From MH to OH)

Wawa-Marathon 230kV #1 and #2 Flow = 157 MW (From East to NW System)

International Falls-Fort Frances 115kV (F3M) Flow = 96 MW (From MP to OH)

(NW Ontario System was importing approximately 370 MW.)

Southern MAPP

GGs East Flow<sup>15</sup> = 1510 MW (From west to east)

Cooper South Interface Flow<sup>16</sup> = 1073 MW (From MAPP to SPP)

Red Willow-Mingo 345kV Flow = 510 MW (From MAPP to SPP)

Sidney (Virginia Smith) DC Loading = 25 MW (From WSCC to MAPP)

Stegall DC Loading = 105 MW (From WSCC to MAPP)

The generation and significant line flows in the NSP control area prior to the Prairie Island-Byron 345kV line trip at 01:34 CDT, and prior to the King-Eau Claire 345kV line trip at 02:18 CDT are shown in Appendix #3 (Sections 3 and 4).

**4.5 Voltages at Key Substations:**

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<sup>14</sup> The 1MW difference is due to losses and DC auxiliary load.

<sup>15</sup> GGS East Flow is sum of real power on the following lines: Gentleman-Sweetwater 345kV #1 and #2 lines, Gentleman-Red Willow 345kV line, and Gentleman-North Platte 230kV #1, #2, and #3 lines.

<sup>16</sup> Cooper South Interface flow is sum of real power on the Cooper-St Joe 345kV line and the Cooper-Fairport-St Joe 345kV line.



Before the trip of Prairie Island-Byron 345kV line at 01:34 CDT, system voltages were within normal operating limits in both the MAPP system and the Northwestern Ontario Hydro system. The table below shows normal voltage values in southern Minnesota at 01:00 CDT.

**Table 3 – Voltages (kV) in southern Minnesota at 01:00 CDT**

| Time (CDT) | Byron 345kV bus | Byron 161kV bus | Maple Leaf 161kV bus | Rochester 161kV bus | Rochester 161kV bus |
|------------|-----------------|-----------------|----------------------|---------------------|---------------------|
| 01:00      | 345.3           | 162             | 163.1                | 162.6               | 161.6               |

Voltages in the NSP control area were normal prior to the King-Eau Claire 345kV line trip at 02:18 CDT, and were restored to normal levels immediately after the disturbance. The table below shows the voltages at several critical NSP buses, prior to and during the disturbance. As can be seen from the table, the voltages on the stressed east interconnections from the Twin Cities area towards MAIN were still acceptable at 02:00 CDT following the trip of the Prairie Island-Byron 345kV line at 01:34 CDT.

**Table 4 – NSP Control Area Voltages (kV) Prior To and After Disturbance**

| Time (CDT) | King 345kV | Eau Claire 345kV | Eau Claire 161kV | Prairie Island 345kV | Byron 345kV | Wilmarth 345kV |
|------------|------------|------------------|------------------|----------------------|-------------|----------------|
| 01:00      | 349        | 341              | 164              | 353                  | 350         | 350            |
| 02:00      | 350        | 334              | 165              | 355                  | 341         | 343            |
| 03:00      | 357        | 364              | 165              | 355                  | 359         | 354            |
| 04:00      | 355        | 360              | 164              | 352                  | 358         | 355            |

The voltages in the Alliant-IPW system, south of the Twin Cities, were also normal after the initial trip of the Prairie Island-Byron 345kV line, as shown in the table below:

**Table 5 – Alliant-IPW Voltages (kV) After Prairie Island-Byron 345kV trip**

| Time (CDT) | Lakefield 345kV | Fox Lake 161kV | Heron Lake 161kV | Winnebago 161kV | Adams 161kV | Rock Creek 161kV |
|------------|-----------------|----------------|------------------|-----------------|-------------|------------------|
| 01:38      | 346             | 160            | 165              | 158             | 164         | 162              |

DPC's voltages on the 161kV system were normal after the initial trip of the Prairie Island-Byron 345 kV line, as follows:

**Table 6 – DPC Area Voltages (kV) After Prairie Island-Byron 345kV trip**

| Time (CDT) | Alma 161 Bus A (kV) | Genoa 161 North Bus (kV) |
|------------|---------------------|--------------------------|
| 01:35      | 161.22              | 163.1                    |

Figure #12 shows the voltage at the King 345kV bus (just north east of the Twin Cities), coincident with the trip of the Prairie Island-Byron 345kV line at 01:34 CDT. As can be seen, the King voltage prior to the line trip was around 355kV. When the line tripped, the voltage spiked down to approximately 338kV (98% of nominal). However, the voltage stabilized after that at around 352kV (102% of nominal), which is the normal operating voltage, and remained at this level until several minutes later when the King-Eau Claire 345kV line tripped.

#### **4.6 Abnormal System Conditions:**

The Twin Cities Export (TCEX) was above Operating Guide limits with the Prairie Island-Byron 345kV line out of service prior to the second contingency, trip of the King-Eau Claire 345kV line.

No abnormal system conditions were present which adversely impacted system restoration.

## 5. DESCRIPTION OF THE DISTURBANCE

### 5.1 Initiating Disturbance - Description and Cause

In the morning of June 25<sup>th</sup>, a severe thunderstorm, heading east, crossed the Twin Cities area (Minnesota). Due to this thunderstorm, at 01:34 CDT, a fault was detected by the relays on the Prairie Island-Byron 345kV line, causing the line to trip. A large phase angle existed across the open line. The NSP Operators attempted to reduce the phase angle difference in order to restore the line.

At 01:51 CDT, the NSP Operators contacted the MAPP Security Center Operator (SCO), and requested 50 MW of relief on the King-Eau Claire 345kV line using the MAPP Line Loading Relief (LLR) procedure. The MAPP SCO processed the LLR and requested curtailments across 02:00 CDT or ASAP.

The phase angle did not sufficiently decrease. At 02:11 CDT, NSP requested 100 MW of relief on the Prairie Island-Byron 345kV line, already open, in an attempt to further reduce the phase angle difference. The MAPP SCO issued this second LLR to be effective across 02:30 CDT.

Before the second LLR was posted on the MAPP Communication Network (MCN), at 02:18 CDT, the relays on NSP's King-Eau Claire 345kV line detected a phase to ground fault and tripped the line.

Just prior to the King-Eau Claire 345kV trip, at 02:15 CDT, the Twin Cities Export (TCEX) was 1004 MW, the North Dakota Export (NDEX) was 1297 MW, and the Manitoba Hydro Export (MHEX) was 1253 MW. The approved Operating Guides define a maximum value of 700 MW for TCEX during the outage of the Prairie Island-Byron 345kV line considering the flow conditions in the Northern MAPP region.

Following the tripping of King-Eau Claire 345kV line, the Eau Claire-Arpin 345kV cross-tripped. The western Wisconsin 115kV and underlying system overloaded. At 02:21:31 CDT, after the Ironwood-Park Falls 115kV line tripped, the Twin Cities system was separated from western Wisconsin.

The separation took 3 minutes and 10 seconds. In this period the tie-line flows between OH-MH and OH-MP increased beyond scheduled values. OH Operators made an attempt to ramp the schedules back to the original values, but were unsuccessful. Voltage oscillations in the area of OH-MAPP ties along with heavy local load stressed these interfaces. At 02:21:55 CDT, OH separated from the MAPP system after the tripping of the Manitoba-Ontario tie (Kenora-Whiteshell 230kV line) by overcurrent protection followed by the tripping of the Minnesota - Ontario tie (Fort Frances-International Falls 115kV line) by out-of-step protection. Within 1/10 of a second after Ontario Hydro separated from

MAPP, the OH East-West ties (Marathon-Wawa 230kV lines) tripped separating the NW OH System from the Eastern OH System. Following the loss of all import ties, and because there was insufficient local generation on-line, the NW OH System collapsed and was blacked out.

At 02:21:56 CDT, the Wilmarth-Lakefield 345kV tripped due to distance relay action due to out-of-step conditions, opening the last of the TCEX interface 345kV lines.

The cascading line tripping continued until the entire northern MAPP region was separated from the southern MAPP region. The initial MAPP island formed at 02:22:09 CDT consisted of the Minnesota, Manitoba, North Dakota, and Saskatchewan areas. The frequency in the island ramped to 61.1 Hz and stabilized for about 2 ½ minutes, dropping to 60.8 Hz when Sherco #3 tripped.

At 02:25:14 CDT, the UPA Operator manually tripped the CU DC Pole 1. About 28 seconds later CU DC Pole 2 tripped, starting the formation of the North Dakota island. The Letellier-Drayton 230kV and Boundary Dam-Tioga 230kV lines tripped at this time by out-of-step protection separating North Dakota from Canada. The remaining lines between North Dakota and Minnesota tripped quickly at about 02:25:47 CDT, except for the Grant County-Douglas County 115kV line which remained closed for about 5 minutes after the North Dakota and Minnesota areas lost synchronism. The Minnesota, Manitoba, and Saskatchewan areas remained connected as an island.

The restoration process in the Minnesota, Manitoba, and Saskatchewan area started at 02:25:59 CDT when the Ironwood-Park Falls 115kV line automatically reclosed. The Minnesota-Manitoba-Saskatchewan island was then tied back with the Eastern Interconnection. The remaining lines that tripped in Minnesota and Wisconsin were quickly closed.

The North Dakota island was not reconnected to the Eastern Interconnection until 03:03:39 CDT when Bismarck-Glenham 230kV line was manually closed via SCADA. The remaining lines which tripped forming the North Dakota island were then quickly restored by System Operators.

## **5.2 Transmission Outages-Reasons:**

During the disturbance more than 60 lines tripped due to overloading and out-of-step conditions. The complete list of lines that tripped during the disturbance appears in Appendix #2.

The key line trips that triggered the cascading effects were:

- Prairie Island - Byron 345kV: A fault was recorded and tripping was proper. Restoration was delayed due to a greater than 40 degree voltage angle across the open line.
- King - Eau Claire 345kV: A phase to ground fault was recorded and no improper relay operations have been detected.
- Wilmarth-Lakefield Jct. 345kV: The line tripped at Wilmarth via zone two primary and secondary phase distance relays. IPW reported out-of-step targets and timers. This combination of targets is consistent with a trip for an out-of-step condition.

All transmission line protective relay actions operated correctly in Ontario Hydro.

### 5.2.1 CU DC Tripping During the Disturbance

At 02:21 CDT, UPA System Operators saw oscillating line flows and voltages in the North Dakota coal fields. They also saw that power on the CU DC line was higher than ordered and appeared to be oscillating. The high DC line power was contributing to a large unbalance between Coal Creek Station (CCS) plant output, which had dropped, and the DC line. This was producing a large unscheduled flow into Coal Creek on the AC ties. Operators attempted to reduce this unscheduled flow by manually reducing the DC power using SCADA. This could not be accomplished as there were intermittent DC high power alarms that prevented any control actions by the Coal Creek RTU.

At 02:15 CDT, the Coal Creek Station net generation was 840 MW (520 MW on CCS 1 and 320 MW on CCS 2) with the CU DC schedule set at 810 MW. There was 20 MW<sup>17</sup> flowing into the AC system at Coal Creek. At 02:25 CDT, 7 minutes after the disturbance started, CCS generation was 540 MW net (385/155 MW) and the CU DC loading was 1090 MW. There was a flow of about 530 MW into the Coal Creek bus from the North Dakota AC system. Since monopole operation would provide adequate power transmission for the Coal Creek Station generation at this time, the operator decided to trip one pole to force a reduction in the DC power schedule. This control action could be done using the SCADA RTU at the inverter terminal. At 2:25:14 CDT, pole 1 of the CU DC line was manually tripped.

The trip of pole 1 better balanced the plant and HVDC line power, reducing the unscheduled flow into the Coal Creek DC terminal from the AC system from 530 MW to 90 MW. This produced a sudden increase in the parallel AC system loading as shown, for example, in Figure #24. However, it appears there was an increase in the AC voltage at the Coal Creek bus. This was in part due to the reduction in reactive power requirements of the DC. There were also continuing voltage oscillations at Coal Creek on the 230kV AC bus after the pole tripped. The high voltage at Coal Creek resulted in a protection operation on pole 2, the

<sup>17</sup> The 10MW difference is due to losses and DC auxiliary load

remaining pole, and it tripped at 02:25:42 CDT. The pole tripped on voltage stress protection.

The loss of both poles initiated a trip of Coal Creek Station Unit 2, which was armed to trip for loss of the bipole. The unit tripped about 7 ½ cycles after the pole 2 trip. A runback signal was also sent to CCS Unit 1, which would have runback from 370 MW to about 300 MW in one minute. The decision to arm one unit for loss of the bipole was based on the pre-disturbance conditions of CCS generation at 840 MW and NDEX export at about 1300 MW. Since CCS generation actually decreased as a result of the islanding, the Operator continued the arming of only one unit during this period.

The reason the DC line power had increased during this event was that the CU DC line has a frequency controller that is active when the frequency deviation at Coal Creek exceeds 0.1 Hz. The purpose of this controller is to stabilize Coal Creek bus frequency when the DC line and the Coal Creek units are operating radially (i.e isolated from the North Dakota AC system). For the bus frequency above 60 Hz, this control is allowed to increase DC power up to 400 MW above the power order. The controller has a gain of 300 MW/Hz. For the increase in rectifier-end frequency to about 61 Hz, the frequency control increased the DC power to about 1090 MW at 02:25 CDT. The CU frequency differential damping control was also active, but this control is sensitive to changes in frequency, and it would not react to the steady-state increase in frequency that occurred.

### **5.2.2 Square Butte DC Tripping During the Disturbance**

The Square Butte DC Pole 2 tripped on overfrequency protection at 02:25:44 CDT, when the North Dakota island frequency reached 62.2 Hz. This protection was designed to trip the HVDC system on overfrequency in the event that the Center converter station (rectifier) and the Young 2 generator would become isolated from the local ac system. This was an appropriate protection response.

Although the HVDC system should continue to operate reliably during off-nominal frequency conditions, there are concerns regarding the performance of the harmonic filters tuned to 60 Hz based harmonic frequencies. Inadequate filtering could lead to voltage distortion, which could cause operational problems.

### **5.2.3 North Dakota Island, Post-Separation Oscillation, Slipping**

Immediately following the islanding of North Dakota, a large amplitude low frequency oscillation occurred in the North Dakota island. The dynamic system monitor at the Square Butte Center converter station (ND island) recorded an average value of 61.47 Hz and a frequency of 0.15 Hz for this event. The peak value of the oscillation reached 61.9 Hz. The oscillation was sustained and lasted for 30 seconds. At this time, both the cause and the mitigating event are unknown. (See details in Figure #16)

The North Dakota island did not cleanly separate from Minnesota because one 115kV line remained connected between the two asynchronous systems. The slipping between the two areas (at approximately 1.5 Hz) was observable in the voltages throughout the MAPP system from about 02:26 CDT until 02:31 CDT. These voltage oscillations can be most clearly seen in Figure #16, which shows the line-to-neutral voltage at the Center 230kV bus in central North Dakota. The voltage oscillation can also be clearly seen at the King 345kV bus on the eastside of the Twin Cities in Figure #15. Oscillations can be seen as far north as Saskatchewan in Figures #21 and #22. Figure #13 shows the same voltage excursions (at a reduced resolution) at the Bismarck 230kV bus in central North Dakota.

The Douglas County-Grant County 115 kV line (Figure #2) in western Minnesota was the last tie line to trip in the formation of the North Dakota island, but did not trip for the out-of-step condition. This line has zone 2 out-of-step blocking at the Grant County end. The Douglas County end relaying has zone 1 and zone 2 out-of-step blocking. The line sections further to the west and east of this line, also have out-of-step blocking, so no line protection in the area was able to open this last interconnection.

The Douglas County -Grant County 115kV line did finally trip approximately 5 minutes after the initial formation of the North Dakota Island due to a fault at the Douglas County end. When crews arrived at the Douglas County substation they found a damaged out of service wave trap and observed the wave trap leads were flapping in the wind. Apparently the flapping leads of the wave trap at Douglas County caused a fault which opened the line, or what ever damaged the wave trap also caused the fault. The exact cause is unknown.

### 5.3 Loss of Generation-Description and Reasons

During the disturbance, a total of 4,171 MW of generation was disconnected in the MAPP and Northwestern OH systems. Almost all of this generation was tripped in a period of approximately 4 minutes.

The generation that tripped off-line during the disturbance, in chronological order, is shown below. Additional information on the generation trips can be found in the sequence of events.

**Table 7 – Generation that tripped during the Disturbance**

| Units Tripped | Net MW Tripped | Time Tripped (CDT) | Time Back On-line (CDT) | Reason for Trip |
|---------------|----------------|--------------------|-------------------------|-----------------|
|               |                |                    |                         |                 |

| Units Tripped                | Net MW Tripped | Time Tripped (CDT) | Time Back On-line (CDT) | Reason for Trip                  |
|------------------------------|----------------|--------------------|-------------------------|----------------------------------|
| Jenpeg #3-4                  | 60             | 02:21:50           | 02:51                   | Over-frequency                   |
| Ft Randall Units #1-6 & 8    | 42             | 02:21:57           | 03:57                   | Over-excitation                  |
| Winton #2                    | 2.0            | 02:21:58           | 03:03                   | Over-speed                       |
| Neal #4                      | 490            | 02:21:58           | 08:41                   | Generator Distance Relay         |
| Cedar Falls Streeter unit #7 | 8              | 02:22:01           | 09:27                   | Loss of field protection         |
| Knife Falls #1,2 and 3       | 1.9            | 02:22:02           | 03:01                   | Over-speed                       |
| Hoot Lake #3                 | 18             | 02:22:10           | 04:45                   | Low load                         |
| Fox Lake #3                  | 18             | 02:22:13           | 04:38                   | Over-excitation                  |
| Poplar River #2              | 291            | 02:22:13           | 03:15                   | Over-frequency                   |
| Riverside #7                 | 66             | 02:22:35           | 06:28                   | Unknown                          |
| Neal #3                      | 430            | 02:22:35           | 04:37                   | High Volt/Hz                     |
| Neal #2                      | 92             | 02:23:02           | 06:56                   | High Volt/Hz                     |
| Bayfront #4,#5 and #6        | 31             | 02:24:21           | 03:30                   | Over-frequency                   |
| Sherco #3                    | 738            | 02:24:58           | 11:35                   | Low drum level                   |
| Bigstone                     | 342            | 02:25              | 11:30                   | Boiler problem                   |
| Coal Creek #2                | 320            | 02:25:12           | 04:45                   | Loss of bipole                   |
| Blanchard #1,2 and 3         | 17.7           | 02:25:50           | 03:11                   | Over-speed                       |
| Antelope Valley Station #2   | 370            | 02:25:55           | 10:01                   | Over-frequency                   |
| Coyote                       | 367            | 02:26:17           | 13:54                   | Boiler Load Rejection            |
| Hoot Lake #2                 | 32             | 02:26:20           | 04:36                   | Fuel Problem                     |
| Highbridge #6                | 149            | 02:26:51           | 04:37                   | Manual trip (Overfire Condition) |
| Grand Island Cherry #3       | 15             | 02:37              | 09:55                   | Fuel trip in boiler              |
| <b>Total MAPP</b>            | <b>3900.6</b>  |                    |                         |                                  |
|                              |                |                    |                         |                                  |
| <b>Thunder Bay #3</b>        | <b>153</b>     | <b>02:22:04</b>    | <b>09:35</b>            | <b>System Collapse</b>           |
| <b>Other OH Hydro</b>        | <b>113</b>     | <b>02:22:04</b>    | <b>09:35</b>            | <b>System Collapse</b>           |
|                              |                |                    |                         |                                  |
| <b>Total NW OH</b>           | <b>270</b>     |                    |                         |                                  |
|                              |                |                    |                         |                                  |
| <b>Total</b>                 | <b>4170.6</b>  |                    |                         |                                  |

The Manitoba Hydro (MH) DC reductions and other protective actions on the MH bipoles reduced the bipole line flows by approximately 1200 MW during the disturbance. The 1200 MW decrease in DC power included a 265 MW DC reduction for trip of Manitoba - Ontario tie (Whiteshell-Kenora 230kV #1, K21W), a 340 MW DC reduction for operation of Forbes DCAR relay, a 250 MW decrease due to over-frequency tripping of bipole 2 valve groups 31 and 42, and a 300 MW decrease due to operation of the DC damping control. These DC



reductions removed another 1080 MW<sup>18</sup> of generation resource from the MAPP system in addition to the generation losses shown above. During the separations and islanding, this reduction was beneficial as it preserved the ties between MH and Minnesota and reduced the overfrequency in the island.

Except for over-frequency tripping of HVDC valve groups, the MH DC power decreases were the result of control actions and resulted in a very brief loss of generation capability to MAPP. The four DC valve groups were returned to service by 02:41 CDT. Export schedules were restored to the U.S. utilities in Minnesota and North Dakota by 03:22 CDT. Export schedules to Wisconsin were further delayed by transmission outages outside the Manitoba System.

The majority of the generation losses during the disturbance were due to the overfrequency conditions in the northern MAPP islands. The generation tripping in southern MAPP was primarily due to over-excitation caused by these units significantly increasing reactive power output as the northern MAPP system was separating from southern MAPP and a significant amount of power surged through the area. The MEC's Neal units in western Iowa clearly show the impact of the power surges as seen in Figure #18. The generation losses in Ontario were due to the complete collapse of the system.

A significant amount of additional generation in the MAPP region was almost lost during the disturbance.

Large power swings at the Gerald Gentleman Station (1107 MW net) in central Nebraska were observed by the NPPD Generation Control Operator. The Generation Control Operator instructed the unit operators to take the units "in hand" to keep them from tripping. NPPD's Cooper Nuclear Station personnel reported being within 0.2 volts of tripping the unit (761 MW net) due to loss of auxiliary equipment.

### **5.3.1 Generation Unit Response in North Dakota island**

The North Dakota island formed about 02:25:47 CDT. The ND island frequency increased to over 62 Hz, and then stabilized during the duration of the island at about 61.3 Hz.

The affected Control Area Operators correctly disabled AGC on a temporary basis during the islanding, due to the high frequency, and the uncertainty concerning the system separations.

For the WAPA (Upper Great Plains Region) Control Area, which was split across the island boundaries, AGC was suspended at 02:10 CDT by automatic action

<sup>18</sup> The 265MW DC reduction for the Kenora-Whiteshell 230kV line trip only represents a loss of generation to the MAPP system of about 145MW because the pre-disturbance flow on the tie line was 120MW from MH to Ontario. The actual reduction exceeded the initial tie line loading because of the large inadvertent flow on the line following the loss of the two Twin Cities 345kV lines.

based on the frequency deviation. WAPA Operators attempted to resume AGC at 02:23 CDT on Tie Line Bias, but this was unsuccessful. Control was switched to constant frequency at 02:59 CDT and back to Tie Line Bias at 03:06 CDT (following the restoration of the North Dakota system to the Eastern Interconnection). The Oahe plant was placed back on normal AGC control at 03:17 CDT.

The Otter Tail Power Company (OTP) Control Area was within the North Dakota island and lost all three units capable of AGC by 02:26 CDT. The regulation service dynamic schedule with Manitoba Hydro was turned off at 02:30:11 CDT because the OTP control area was separated from the MH control area at 02:25:42 CDT and remained off until 02:50:47 CDT. However, the tie line between the control areas was not returned to service until 03:25 CDT when the Letellier-Drayton 230kV line was energized. Thus, the OTP control area lost their AGC capability during the disturbance and subsequent islanding. Also, the regulation service dynamic schedule was restored prior to the North Dakota being resynchronized with the Eastern Interconnection.

For the United Power Association (UPA) Control Area, AGC tripped off-line at about 02:22 CDT due to sudden frequency deviation. AGC was returned to normal later in the morning when the system was restored.

For the Northern States Power Company (NSP) Control Area, Sherco units #1, #2, and #3 were on AGC prior to the disturbance. After Sherco #3 tripped at 02:25 CDT, the NSP Plant Operators switched Sherco units #1 and #2 into manual control mode, effectively disabling the AGC.

The Manitoba Hydro (MH) System Control Centre (SCC) tripped off AGC at 02:26 CDT due to the disturbance, and returned AGC to normal at 02:41 CDT.

Reductions and significant fluctuations in the net output of generating units were experienced in the North Dakota island. The following unit responses were reported.

- At the Coal Creek Station (CCS), at 02:15 CDT, CCS 1 was at 520 MW net output and 320 MW net on CCS 2. At about 02:25 CDT, a reduction in generation followed the frequency increase to 61 Hz: CCS 1 was at 385 MW net and CCS 2 at 155 MW net.
- Young 1 remained constant at 210 MW, with rapid 10 to 50 MW fluctuations due to governor actions.
- Young 2 began to governor-induced ramp down from 415 MW net at 02:23 CDT to 335 MW at 02:30 CDT. Once the governor was satisfied, the turbine began ramping back up to 410 MW net at 03:03 CDT. After that, per dispatch request, the unit began to ramp down to 270 MW at 03:45 CDT.

#### **5.4 Voltage and/or Frequency excursions**

The system voltages and frequency recovered well after the Prairie-Byron 345kV line tripped. A spike in the frequency, reaching 60.2 Hz, was observed at the Arrowhead bus, however the frequency returned to normal rapidly. The frequency stabilized at near normal values after the subsequent trip of King-Eau Claire 345kV line. Figure #6 shows the system frequency after the Prairie Island-Byron 345kV line trip. Figure #7 shows the system frequency after the subsequent King-Eau Claire 345kV line trip.

Significant frequency excursions began to take place during the ensuing system separation and in the islands that formed. The following are some observations about the frequency excursions and oscillations in the Northern MAPP area:

- When the second contingency (King-Eau Claire 345kV line trip) occurred a frequency spike to 60.17 Hz at Arrowhead (see Figure #7) but was damped rapidly and stabilized to 60 Hz.
- During the Twin cities-Northwest Wisconsin separation, oscillations, with average value of 60 Hz and maximum amplitude of 0.16 Hz, were observed at Arrowhead (see Figure #8).
- The frequency in the Minnesota/Manitoba/North Dakota/Saskatchewan island increased up to 61.11 Hz (see Figure #9). After that it stabilized, with some minor oscillations, at a value close to 60.8 Hz.
- When North Dakota separated from the northern MAPP island, the frequency in the Minnesota/Manitoba/Saskatchewan island dropped to 59.95 Hz and finally recovered when the island was reconnected to the Eastern Interconnection.
- The frequency in the North Dakota island increased to 62.2 Hz (See Figure #5) and then settled at an average value of about 61.3 Hz for approximately 30 minutes.

In the southern and eastern MAPP regions frequency dropped after Minnesota/Manitoba/North Dakota/Saskatchewan island formed. In the east, DPC reported frequency excursions from 59.91 Hz up to 60.04 Hz. In the south, NPPD reported excursions from 59.50 Hz to 60.066 Hz and MEC reported excursions from 59.4 Hz to 60.04 Hz. IPW reported excursions from 59.925 Hz to 60.015 Hz

Prior to 02:18 CDT, the voltages in the MAPP region were normal and within operational limits. Once the cascade line tripping and system separations began, significant voltage changes and swings were observed throughout the MAPP system.

In the DPC system, severe transient voltage oscillations occurred. At Adams 161kV bus 2, voltage ranged from 150.1kV at 02:21 CDT to 170.6kV at 02:25 CDT. Figure #23 shows the voltage swings at Alma 161kV bus A. The Barron 161kV bus voltage varied from 140.9kV (87%) at 02:21 CDT to 165.2kV at 02:25

CDT. The Winnco 69kV bus voltage varied from 62.6kV (91%) at 02:21 CDT to 75.8kV (110%) at 02:22 CDT. The Winnco 161kV bus voltage reached 191kV (119%).

The WAPA area also experienced voltage oscillations. Prior to the tripping of King-Eau Claire 345kV, the Bismarck 230kV bus was about 240kV. After the trip of King-Eau Claire 345kV line, the Bismarck 230kV bus voltage dropped to about 232kV. The Bismarck voltage then jumped to about 247kV during the Minnesota/Manitoba/North Dakota/Saskatchewan island formation, and then dropped quickly to about 237kV. When the North Dakota island formed, the Bismarck 230kV bus voltage jumped to about 252kV. During approximately 5 minutes when North Dakota slipped against Minnesota, the voltage began oscillating between 241kV and 251kV. Figure #13 shows the voltage fluctuations on the Bismarck 230kV bus. Most of the WAPA North Dakota system experienced a similar pattern of voltage fluctuations during this timeframe.

Similar voltage oscillations were experienced on the Tioga side of Boundary Dam phase shifter (SPC, Canada). Before the King-Eau Claire 345kV line trip, voltages were within operational limits at 230kV. During the system separation coinciding with the formation of the Minnesota/Manitoba/Saskatchewan/North Dakota island, the Boundary Dam bus voltage dropped to around 200kV. Following the trip of the Tioga-Boundary Dam 230kV line in the subsequent formation of the North Dakota island, the Boundary Dam 230kV bus voltage increased up to 274kV and the 5-minute oscillation during the system slipping can also be seen in Figures #21 and #22.

Voltage swings at the King 345kV bus following the Wilmarth-Lakefield 345kV line trip are shown in Figure #14. The King 345kV voltage jumped from 350kV to 375kV in milliseconds. The voltage oscillations during the system slipping can also be seen at the King 345kV bus. Figure #15 shows the voltage oscillation with an amplitude of about 4.5kV with an average value of approximately 363kV.

The response of the Watertown Static Var System (SVS) in eastern South Dakota during the North Dakota/Minnesota slipping can be seen in Figure #19. The SVS reduced the voltage oscillations in the area.

The voltage at the Gentleman 345kV Bus (in central Nebraska) changed significantly from 343kV to 374kV during the disturbance.

Significant real and reactive power swings were observed throughout southern MAPP. The reactive output at the Cooper Nuclear Station in southeastern Nebraska changed from supplying 142Mvar to supplying 369Mvar, and then back to absorbing 39Mvar within a period of 20 seconds. The Cooper real power output changed from 761 MW to 866 MW and down again to 666 MW during the disturbance. Swings of 200 to 300Mvar were seen at the Gentleman plant in central Nebraska. The Cooper South interface flows (sum of the Cooper-

Fairport and Cooper-St. Joe 345kV lines) changed from 1073 MW up to 1370 MW, and then down to 297 MW during the disturbance.

### 5.5 Load Losses-Magnitude/Duration and Reasons:

The following tables show the amount of load lost and the number of customers affected during the disturbance in the MAPP region and in the OH system.

**Table 8 - MAPP Member Load Losses**

| Company           | Load Lost (MW) | Total MW-Minutes     | # Customers Affected |
|-------------------|----------------|----------------------|----------------------|
| CP                | 18             | 9,709 MW-min         | N/A                  |
| DPC               | 12             | 504 MW-min           | 2,370                |
| IPW               | 20             | 1,597 MW-min         | 6,270                |
| MDU               | 10             | 845 MW-min           | 7,300                |
| MP                | 120            | 23,040 MW-min *      | 6                    |
| NPPD              | 65             | 4,010 MW-min *       | 3                    |
| NSP               | 31.2           | 1,228 MW-min         | 16,000               |
| OTP               | 36.6           | 4,006 MW-min         | 7,154                |
| <b>Total MAPP</b> | <b>312.8</b>   | <b>44,939 MW-min</b> | <b>39,103</b>        |

\* Industrial Customers

**Table 9 - Ontario Hydro Load Losses**

| Company | Load Lost (MW) | Total MW-Minutes | # Customers Affected           |
|---------|----------------|------------------|--------------------------------|
| OH      | 650            | 90,400 MW-min    | 113,770 retail & 23 industrial |

The main reason for the loss of load was under-voltage load shedding. However, in some cases, the tripping of the transmission lines feeding the load caused the loss. The duration of the loss of load, due to the disturbance, in the MAPP region, varied between 1 minute and 3 hours.

In the Ontario Hydro system, the loss of load was due to a total collapse of their Northwestern system. The duration of the load lost varied from 1 to 4.5 hours.

### 5.6 Underfrequency load shedding performance:

No automatic underfrequency load shedding occurred during the disturbance in the MAPP region.

Based on minimum frequency excursion of approximately 59.4 Hz in the southern MAPP system, which remained connected to the Eastern Interconnection, no automatic underfrequency load shedding was expected. The MAPP underfrequency load shedding program<sup>19</sup> correctly did not operate, as it requires the first stage of automatic load shedding at 59.3 Hz. The islands that formed had a significant amount of surplus generation, with the frequency well above 60 Hz, and therefore no load was shed in the islands on underfrequency.

After the frequency decline in the southern MAPP was arrested, no manual load shedding was implemented.

Ontario Hydro underfrequency load shedding operated, but the undergenerated NW OH island collapsed much faster than the load shedding could take place.

### **5.7 Special Protection Scheme performance:**

The Special Protection Schemes (SPS) associated with the Manitoba Hydro DC reductions that occurred during the disturbance all operated properly. The two MH DC reductions during the disturbance were as follows:

- Following the Kenora-Whiteshell 230kV line (K21W) trip, a 265 MW MH DC reduction was correctly initiated at 02:21:54:880 CDT.
- In response to system swings, the Forbes DCAR (Delta Current Admittance Relay) operated, and a 340 MW MH DC reduction was correctly initiated at 02:21:57.486 CDT. The 340 MW of DC reduction was beneficial for the over generating islanding condition. However, the operation of the Forbes DCAR relay was "as designed but not as intended". The design did not anticipate operation of the relay for the unusual conditions which occurred. Operation for similar local conditions at Forbes, but for different system circumstances, would likely be undesirable.

The operations of the SPS were adequate and as expected. However, the SPS operation was not expected for the DC reduction initiated by the Forbes DCAR relay.

### **5.8 Communications/SCADA system performance:**

Several MAPP Members had SCADA problems during the disturbance. Otter Tail Power Company (OTP) indicated that their system lost data such as alarms and messages. The United Power Association (UPA) System Operator experienced difficulty in completing control actions at a critical substation when the disturbance caused several points to continuously cycle in and out of alarm. Dairyland Power Cooperative (DPC) indicated that their Apple River RTU

<sup>19</sup> MAPP Operating Handbook, Section IV

communications failed during the disturbance. Omaha Public Power District's (OPPD) EMS system, due to prioritization of tasks during the heavy alarm/event loading, failed to record frequency data from 02:22 to 02:23:30 CDT. MEC lost SCADA data due to the large number of alarms that occurred. Ontario Hydro also indicated that their system lost some data.

The MAPP Communications Network (MCN) operated properly during the disturbance.

#### **5.9 System Restoration-Description/Significant Issues:**

Given the magnitude of the disturbance, the restoration process in the transmission system was achieved quickly. In the MAPP region, the restoration process started at about 02:26 CDT, with the reconnection of the Minnesota/Manitoba/Saskatchewan island to the Eastern Interconnection. The process finished at 04:47 CDT (2 hours and 29 minutes after the King-Eau Claire 345kV line trip) when the ties between Minnesota Power and the NW OH system were closed. The Alma-Rock Elm 161kV line was not restored until June 27<sup>th</sup> due to damage to 5 structures caused by the severe thunderstorm.

Restoration in NW OH system started with OH closing its ties to the eastern OH system at 03:12 CDT. At 05:46 CDT, the 230kV system was restored and at 06:00 CDT potential was restored to all customer loads.

The automatic re-closure of the Ironwood-Park Falls 115kV line (Western Wisconsin), which occurred at 02:25:59 CDT, initiated the restoration process in the eastern portion of the MAPP region. The automatic re-closure of this line tied back the Minnesota/Manitoba/Saskatchewan island to the Eastern Interconnection. This happened while the North Dakota island was already slipping against the Eastern Interconnection.

Restoration of the NSP transmission system started with lines that connect the Twin Cities with eastern Wisconsin. At 02:26:22 CDT, the King-Eau Claire 345kV line was back in service and seven minutes later the Prairie-Island 345kV line was restored. However, the 345kV tie with MAIN was not restored until 03:03 CDT, when the Eau Claire-Arpin 345kV line was returned to service. The last TCEX interface line, the Wilmarth-Lakefield 345kV line, was restored at 03:19 CDT. The NSP transmission system was back to normal (almost 1 hour after the King-Eau Claire 345kV line trip).

The reconnection between the North Dakota island and the Eastern Interconnection began with the manual restoration of the Bismarck-Glenham 230kV line. The remaining ties were quickly closed.

The CU HVDC was out of service from 02:25 CDT until 03:45 CDT when the Pole 1 was de-blocked. Nine minutes later, Pole 2 was de-blocked. The SQBT

DC Pole 2 was restarted at 03:48 CDT, after being out of service since 02:25:44 CDT.

No major problems occurred in the restoration process for the transmission system.

All of the MAPP systems reported normal operations by 21:00 CDT. The Northwestern Ontario system was restored to normal conditions by 06:45 CDT.

#### **5.9.1 Generation Restoration:**

The majority of the generating units that tripped were restored with no problems.

MAPP Members reported problems bringing three units back on-line after the disturbance:

- Big Stone plant (425 MW net capability) tripped off line at 02:25 CDT. The unit was brought on-line at 09:06. The plant tripped off-line at 09:18 due to a boiler problem unrelated to the disturbance. The Big Stone plant was back on-line at 09:49 and remained on-line.
- Coyote plant (400 MW net capability) tripped off-line at 02:26 CDT. The unit was brought on line at 05:11. MDU held Coyote off-line until they were sure there was sufficient power on the network to start Coyote up. The plant tripped off-line at 06:48 due to a problem with fans. The unit was on and off-line several times due to problems associated with turbine controls, which were unrelated to the disturbance. The Coyote plant was back on-line at 13:54 and remained on-line.
- Sherco #3 unit (871 MW capability) tripped off-line at 02:24:51 due to a low drum level. The unit was brought on line at 11:35. Sherco #3 had a boiler relief valve that stuck open. The valve had to be replaced before the unit could be brought back on-line.

Due to the delay in the restoration of the Sherco #3 unit (871 MW) and the continuing maintenance outage of the King unit (567 MW), NSP declared an "energy alert" for later in the day on June 25<sup>th</sup>. NSP was forecasting a 1000 MW generation deficit due to the expected hot weather and these unit outages. NSP made a public appeal to their retail, commercial, and industrial customers to reduce power usage. This public appeal was expected to last until 20:00 CDT on June 25<sup>th</sup>. With the return of the Sherco #3 unit sooner than expected, the power reductions realized from "interruptible" customers, and NSP's ability to obtain larger energy purchases than expected, NSP was able to lift the "energy alert" and cancel the public appeal at 16:30 CDT. The public appeal was successful.



### 5.10 MAPP Emergency Replacement Procedure (EM) Calls

During the disturbance, several MAPP Members invoked the MAPP Emergency Replacement Procedure (EM)<sup>20</sup>, due to the loss of generating units. The EM program is the mechanism that MAPP Members have to establish the individual amount of reserve contributions after the loss of a specific generator.

During the disturbance, eight EM calls were made in a period of 11 minutes as shown in the following table. Specific details of the EM requests are included in the Sequence of Events.

**Table 10 – Summary Of MAPP Emergency Replacement Requests**

| EM Call      | Time (CDT) | Company  | Generation Unit Lost | Requested MW   |
|--------------|------------|----------|----------------------|----------------|
| 1            | 02:28      | MEC-ALT  | Neal 3               | 450            |
| 2            | 02:31      | SMP      | Sherco 3             | 230            |
| 3            | 02:32      | OTP      | Big Stone *          | 219            |
| 4            | 02:34      | OTP      | Coyote *             | 140            |
| 5            | 02:34      | UPA-GSE  | Coal Creek 2 *       | 630            |
| 6            | 02:36      | NWPS     | Big Stone *          | 95             |
| 7            | 02:37      | NWPS     | Coyote *             | 40             |
| 8            | 02:39      | MEC-NWPS | Neal 4               | 411            |
| <b>TOTAL</b> |            |          |                      | <b>2215 MW</b> |

\* Units isolated in North Dakota island at time of EM Request

The total amount of generation requested at 02:39 CDT was 2215 MW. At that time, the assigned generation reserve for the entire MAPP region was 1280 MW. Due to the transmission system islands during that period (from 02:25:47 to 03:03:39 CDT), the North Dakota island had a significant amount of excess generation on-line even after the units above tripped. The frequency settled at close to 61.3 Hz. The Members in the island requested EM schedules to cover their generation losses, even though the frequency at the time was very high. Due to the separation, the MAPP Members in the North Dakota island were unable to deliver EM schedules to the Members outside the island, and vice versa.

Due the uncertainty concerning the system conditions, several MAPP Members did not immediately comply with the requests for EM schedules. The EM schedule requests were being broadcast right in the middle of the disturbance, which made it difficult to respond to them, as the system Operators were focusing on responding to the emergency conditions.

The WAPA and NSP Operators notified the MAPP Security Center Operator (SCO) during phone conversations during the disturbance, that they were not

<sup>20</sup> MAPP Operating Handbook, Section IV

immediately responding to the EM schedule requests. The WAPA Operators indicated that they were in an island situation and were unsure at that time of the location and extent of the islanding. Based on the extremely high frequency in the control area, and not being able to determine for sure if schedules could actually be delivered to the requesting parties, the WAPA Operators delayed responding to the all EM requests until 03:23 CDT. The NSP Operators were also unsure of the overall system condition, and were concerned that increasing generation, and thus increasing transfers, could cause additional lines to trip. The NSP Operators delayed responding to the EM requests, because of concern about making the system conditions worse, until 04:00 CDT.

UPA also did not respond to the early EM calls because of the disturbance and the loss of Coal Creek Station 2, but began delivering EM schedules starting at 03:48 CDT.

Once the transmission system was restored sufficiently, and the islanded areas reconnected, all of the MAPP Members were compliant with delivering their required EM schedules.

#### **5.11 MAPP SCO Request for Time Error Correction**

During the disturbance, a Time Error Correction was requested by the MAPP SCO. At 02:30 CDT, the operators from KCPL reported to the MAPP SCO a frequency value of 59.95 Hz. The KCPL operator suggested that a Time Error Correction could help boost the frequency.

Four minutes later at 02:34 CDT, the MAPP SCO operator called the NERC Hot Line to report the emergency situation in the MAPP region, and informed them about the possibility of MAPP requesting a Time Error Correction.

At 02:40 CDT, the MAPP SCO sent a Time Error Correction request to American Electric Power (AEP). Five minutes later at 02:45 CDT, the AEP operator informed the MAPP Center that the time error was -4.65 seconds and the target frequency across 03:00 CDT would be 60:02 Hz (Time Error Correction Identification "H").

At 02:49 CDT, the MAPP SCO sent a MCN message to all MAPP Members instituting the Time Error Correction. The North Dakota system was still separated with the frequency in the island at approximately 61.3 Hz at the time the time error was requested.

Several MAPP Member control areas did not implement the requested Time Error Correction (TEC), due to the disturbance. WAPA, whose control area was separated at the time of the request, indicated that they did not respond to the TEC. When the TEC was requested, the WAPA control area was off AGC. UPA has indicated that at the time of the TEC request that they were still recovering

from the disturbance and the loss of the CU DC line and Coal Creek Station #2, and therefore did not participate.

The times at which Members in the MAPP region initiated the Time Error Correction varied. For example, NPPD initiated the Time Error Correction at 02:49 CDT and removed it at 03:41 CDT. OTP responded to the request, initiating the correction at 03:01 CDT and removing it at 04:10 CDT.

Around 03:00 CDT, the low frequency in the MAPP system tied to the Eastern Interconnection began to immediately increase as shown in Figure #20, and was soon at the targeted value of 60.02 Hz. At 03:03:39 CDT, the North Dakota island was reconnected to the Eastern Interconnection restoring significant generation to the MAPP region.

Minutes later at about 03:13 CDT, the frequency of the interconnected system reached approximately 60.035 Hz. At 03:41 CDT, the MAPP SCO called AEP to request that the Time Error Correction be terminated. AEP issued the Time Error Correction termination for across 04:00 CDT. The MAPP SCO broadcast an MCN message to all MAPP Members requesting that the Time Error Correction be terminated at 04:00 CDT.

## **6. SEQUENCE OF EVENTS**

A chronological listing of all of the relevant transmission and generation outages, and islanding which occurred during the disturbance is included as Appendix #5. The sequence of events also lists the export conditions, relevant communications between the MAPP member system and the MAPP Security Center Operator, MAPP EM Procedure calls, and other relevant events that occurred during the disturbance.

**Appendix #1**

**List of parties contributing to the Disturbance Report**

MAPP Staff

Mike Brytowsky  
LaWayne Buelow  
Johan Galleberg  
Carlos Gonzalez-Perez  
Tim Liffbrig  
Barry McMahon  
Ben Porath  
Zachary Gerbozy

IORWG Members and contributors:

Ken Goldsmith, Alliant Utilities-IES (IES)  
Jarred Miland, Alliant Utilities-Interstate Power (IPW)  
Dick Pursley, Alliant Utilities-Interstate Power (IPW)  
Richard Hegna, Corn Belt Power Cooperative (CBPC)  
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Ken Moss, MidAmerican Energy (MEC)  
Larry VanWyhe, MidAmerican Energy (MEC)  
Richard Huebner, Muscatine Power and Water (MPW)

NORWG Members and contributors:

Barry Francis, Basin Electric Power Cooperative (BEPC)  
Al Meyer, Hastings Utilities (HU)  
Laurie Gregg, Lincoln Electric System (LES)  
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Ron Gunderson, Nebraska Public Power District (NPPD)  
Brian Brownlow, Nebraska Public Power District (NPPD)  
John Mayhan, Omaha Public Power District (OPPD)  
David Kulisek, Omaha Public Power District (OPPD)  
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NMORWG Members and contributors:

Mike Risan, Basin Electric Power Cooperative (BEPC)  
Mike Steckelberg, Cooperative Power (CP)  
Terry Torgerson, Dairyland Power Cooperative (DPC)  
Bob Roddy, Dairyland Power Cooperative (DPC)  
Wayne Haidle, Montana-Dakota Utilities (MDU)  
Robert Coish, Manitoba Hydro (MH)  
Allan Silk, Manitoba Hydro (MH)  
George Sweezy, Minnesota Power (MP)

**Appendix #1 (Continued)**

**List of parties contributing to the Disturbance Report**

NMORWG Members and contributors (continued):

Dudley Maki, Minnesota Power (MP)  
Dennis Swanson, Minnkota Power Cooperative, Inc. (MPC)  
Tim Bartel, Minnkota Power Cooperative, Inc. (MPC)  
Dean Schiro, Northern States Power Co. (NSP)  
Darwin Porter, Northern States Power Co. (NSP)  
Greg Pieper, Northern States Power Co. (NSP)  
Mike McMullen, Northern States Power Co. (NSP)  
Terry Volkmann, Northern States Power Co. (NSP)  
Dale Jepsen, Northwestern Public Service Company (NWPS)  
Larry Larson, Otter Tail Power Company (OTP)  
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Earl Cass, Western Area Power Administration (WAPA)  
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Other MAPP:

Jeff Ihrke, Southern Minnesota Municipal Power Agency (SMMPA)

Ontario Hydro

Mike Radan  
Kenneth Chan  
Chak M. Louie

## Appendix #2

### Transmission facilities (69kV and above) that tripped during Disturbance

#### DPC:

Alma-Rock Elm 161kV (5 structures down due to storm damage)  
Apple River-Crystal Cave/Pine Lake (Open-ended at Apple River)  
Twin Lakes-Winnco 69kV (Open-ended at Twin Lakes)  
Apple River 69kV Bus and associated 69kV lines  
Barron-Pine Lake 69kV (Open-ended at Barron)

#### Alliant-IPW:

Lakefield-Fox Lake-Winnebago-Hayward 161kV  
Lakefield 345/161 transformer  
Rutland-Fox Lake 69kV  
Albert Lea Westside-Walters 69kV  
Fox Lake-Dunnel 69kV (radial)  
Winnco-Thompson 69kV  
Fox Lake-Sherburn 69kV  
Winnco-Forest City 69kV  
Montgomery-New Prague 69kV

#### MDU:

Tioga 230/115kV transformer (Open-ended on 230kV side)

#### MEC:

Lakefield-Raun 345kV

#### MH:

Kenora-Whiteshell 230kV (K21W)  
Letelier-Drayton 230kV

#### MP:

Stinson-Minong 161kV (Open-ended at Stinson)  
International Falls-Fort Francis Phase Shifter (F3M) 115kV  
Audubon-Hubbard 230kV  
Rush Lake Tap-Wing River 230kV  
Square Butte HVDC Pole #2

**Appendix #2 (Continued)**

**Transmission facilities (69kV and above) that tripped during Disturbance**

NSP:

Prairie Island-Byron 345kV  
King-Eau Claire 345kV  
Eau Claire-Arpin 345kV  
Wilmarth-Lakefield Jct. 345kV  
Afton-Red Rock 115kV  
Red Rock-Crystal Cave 115kV  
Pine Lake-Wissota 115kV  
Pine Lake-Apple River/Crystal Cave 161kV  
South Faribault-West Owatonna 161kV  
Ironwood-Park Falls 115kV  
Wilmarth-Winnebago 161kV  
Pathfinder-Split Rock 115kV  
Panther-Granite Falls 230kV  
Minnesota Valley-Franklin 115kV  
Willmar-Kerkhoven/Minnesota Valley Jct. 115kV  
T-Corners - Wien 115kV  
Cannon Falls - Northfield 69kV  
Cannon Falls - Zumbrota 69kV  
Cannon Falls - Spring Creek 69kV  
Pine Lake - Rock Elm 69kV  
Red Wing - Alma 69kV  
Stone Lake - Bayfront 69kV  
MN Valley - Bird Island 69kV  
Willmar - Granite Falls 69kV  
Douglas County - Westport 69kV  
Douglas County - Osakis 69kV

NWPS:

Huron-Redfield 115kV  
Huron West Park-Mitchell 115kV

OH:

All 230kV, 115kV and below in the NW OH system (west of Wawa)

OPPD:

Raun-Fort Calhoun 345kV



**Appendix #2 (Continued)**

**Transmission facilities (69kV and above) that tripped during Disturbance**

OTP:

Grant-Douglas County-Alexandria 115kV  
Toronto-Burr 115kV (Open at Toronto)

UPA:

Prairie-Ramsey 230kV  
McHenry-Ramsey 230kV  
Granite Falls-Willmar 230kV  
CU HVDC Pole #1 and CU HVDC Pole #2

WAPA:

Bismarck-Glenham-Sully Buttes 230kV line  
Fort Thompson terminal of the Leland Olds 345kV line  
White-Split Rock 345kV line  
Fort Thompson-Huron No.1 230kV line  
Fort Thompson-Huron No.2 230kV line  
Huron terminal of the Storla 115kV line  
Brookings terminal of the Flandreau 115kV line  
Hettinger-Maurine 230kV line  
Tioga-Boundary Dam 230kV line

**Appendix #3****Conditions Prior to the Disturbance****1. Generation off-line/out of service:****1.1 Minnesota/Manitoba/Saskatchewan Island Area**

| <b>Company</b> | <b>Generation Units<br/>Off-line/Out of Service</b> | <b>Capability (MW)</b> |
|----------------|-----------------------------------------------------|------------------------|
| MH             | Brandon                                             | 93.6                   |
| MH             | Grand Rapids                                        | 236                    |
| MP             | Hibbard 3                                           | 36.8                   |
| MP             | Hibbard 4                                           | 15                     |
| NSP            | Angus Anson 2                                       | 116                    |
| NSP            | Angus Anson 3                                       | 116                    |
| NSP            | Big Falls 2 - 3                                     | 5.1                    |
| NSP            | Black Dog 1                                         | 75                     |
| NSP            | Black Dog 3                                         | 109                    |
| NSP            | Blue Lake 1 - 4                                     | 203                    |
| NSP            | Chippewa Falls 2 - 6                                | 16.8                   |
| NSP            | Cornell 2 - 4                                       | 19.5                   |
| NSP            | Dells 1 - 7                                         | 8.5                    |
| NSP            | French Island 1 - 4                                 | 171                    |
| NSP            | Granite City 1 - 4                                  | 61                     |
| NSP            | Holcombe 1 - 3                                      | 35.5                   |
| NSP            | Inver Hills 1 - 6                                   | 343                    |
| NSP            | Jim Falls 1, 2, & 4                                 | 57.4                   |
| NSP            | Key City 1 - 4                                      | 65                     |
| NSP            | King 1                                              | 567                    |
| NSP            | Menomonie 1 - 2                                     | 5.3                    |
| NSP            | Minnesota Valley 3                                  | 47                     |
| NSP            | Pathfinder 1                                        | 61                     |
| NSP            | St Croix Falls 6 - 8                                | 9                      |
| NSP            | West Faribault 2 - 3                                | 32                     |
| NSP            | Wheaton 1 - 6                                       | 342                    |
| NSP            | Wilmarth 1 - 2                                      | 22                     |
| NSP            | Wissota 2 - 6                                       | 31.2                   |
| SPC            | Total Generation Off-Line                           | 836                    |
| UPA            | Cambridge CT                                        | 25                     |
| UPA            | Maple Lake CT                                       | 25                     |
| UPA            | Rock Lake CT                                        | 25                     |
| <b>TOTAL</b>   |                                                     | <b>3810.7</b>          |

**Appendix #3 (Continued)****Conditions Prior to the Disturbance****1. Generation off-line/out of service: (Continued)****1.2 North Dakota Island Area**

| <b>Company</b> | <b>Generation Units<br/>Off-line/Out of Service</b> | <b>Capability (MW)</b> |
|----------------|-----------------------------------------------------|------------------------|
| BEPC           | Leland Olds 1 (Unavailable)                         | 210                    |
| OTP            | Hoot Lake 1                                         | 7.6                    |
| OTP            | Jamestown 1 – 2                                     | 41.9                   |
| OTP            | Lake Preston                                        | 21.8                   |
| <b>TOTAL</b>   |                                                     | <b>281.3</b>           |

**1.3 In Northwestern Ontario Area**

| <b>Company</b> | <b>Generation Units<br/>Off-line/Out of Service</b> | <b>Capability (MW)</b> |
|----------------|-----------------------------------------------------|------------------------|
| OH             | Atikokan                                            | 230                    |
| OH             | Hydraulic (Total)                                   | 505                    |
| OH             | Thunder Bay 2                                       | 155                    |
| OH             | West Coast (NUG)                                    | 90                     |
| <b>TOTAL</b>   |                                                     | <b>980</b>             |

**1.4 Southern/Eastern MAPP Area (Nebraska/Iowa/Wisconsin)**

| <b>Company</b> | <b>Generation Units<br/>Off-line/Out of Service</b> | <b>Capability (MW)</b> |
|----------------|-----------------------------------------------------|------------------------|
| DPC            | Flambeau 1 – 2                                      | 14.3                   |
| IPW            | Fox Lake 1, 2, & 4                                  | 45.3                   |
| IPW            | Kapp 1                                              | 18                     |
| IPW            | Lansing 1 – 2                                       | 26.2                   |
| IPW            | Lime Creek 1 – 2                                    | 70                     |
| LES            | 8 <sup>th</sup> & J                                 | 32                     |
| LES            | Rokeby 1 – 2                                        | 136                    |
| MEC            | Louisa                                              | 700                    |
| NPPD           | Columbus 1                                          | 40                     |
| NPPD           | Kingsley 1                                          | 38                     |
| NPPD           | Sheldon 2                                           | 120                    |
| WAPA           | Big Bend 1, 3, 5, 6, & 8                            | 335                    |
| WAPA           | Oahe 3, 5, 6, & 7                                   | 449                    |
| <b>TOTAL</b>   |                                                     | <b>2023.8</b>          |

**Appendix #3 (Continued)****Conditions Prior to the Disturbance****2. Generation on-line (At approximately 02:17 CDT):****2.1 Minnesota/Manitoba/Saskatchewan Island Area**

| <b>Company</b> | <b>Generation Units<br/>On-Line</b> | <b>Net Output (MW)</b> |
|----------------|-------------------------------------|------------------------|
| MH             | Sum of Northern Collector           | 3030                   |
| MH             | Southern Generation                 | 1094                   |
| MP             | Total generation in Island          | 943                    |
| MP             | Young 2 (On SGBT DC)                | 250                    |
| NSP            | Bay Front 4 – 6                     | 31                     |
| NSP            | Big Falls 1                         | 2                      |
| NSP            | Black Dog 2                         | 76                     |
| NSP            | Black Dog 4                         | 144                    |
| NSP            | Cedar Falls 1 – 3                   | 6                      |
| NSP            | Chippewa Falls 1                    | 3                      |
| NSP            | Cornell 1                           | 1                      |
| NSP            | Flambeau 1                          | 1.5                    |
| NSP            | Hennepin Island 1 – 5               | 12                     |
| NSP            | High Bridge 5                       | 78                     |
| NSP            | High Bridge 6                       | 149                    |
| NSP            | Monticello 1                        | 546                    |
| NSP            | Prairie Island 1                    | 502                    |
| NSP            | Prairie Island 2                    | 459                    |
| NSP            | Red Wing 1 – 2                      | 16                     |
| NSP            | Riverside 7                         | 66                     |
| NSP            | Riverside 8                         | 222                    |
| NSP            | Sherco 1                            | 547                    |
| NSP            | Sherco 2                            | 552                    |
| NSP            | Sherco 3                            | 738                    |
| NSP            | St Croix Falls 1 – 5                | 12                     |
| NSP            | Wissota 1                           | 4                      |
| SPC            | Total generation in Island          | 1524                   |
| UPA            | Coal Creek (On CU DC)               | 810                    |
| UPA            | Elk River                           | 33                     |
| <b>TOTAL</b>   |                                     | <b>11851.5</b>         |

**Appendix #3 (Continued)****Conditions Prior to the Disturbance****2. Generation on-line (At approximately 02:17 CDT): (Continued)****2.2 North Dakota Island Area**

| <b>Company</b> | <b>Generation Units On-Line</b> | <b>Net Output (MW)</b> |
|----------------|---------------------------------|------------------------|
| BEPC           | Antelope Valley 1               | 423                    |
| BEPC           | Antelope Valley 2               | 430                    |
| BEPC           | Leland Olds 2                   | 272                    |
| MDU            | Heskett 1                       | 7                      |
| MDU            | Heskett 2                       | 35                     |
| MP             | Young 1                         | 214                    |
| MP             | Young 2 (Into AC)               | 150                    |
| OTP            | Big Stone                       | 408                    |
| OTP            | Coyote                          | 375                    |
| OTP            | Hoot Lake 2                     | 28                     |
| OTP            | Hoot Lake 3                     | 18                     |
| UPA            | Coal Creek (Into AC)            | 30                     |
| UPA            | Stanton                         | 147                    |
| WAPA           | Ft. Peck 4 (3&5 Cond)           | 45                     |
| WAPA           | Garrison 1-5 (2&4 Cond)         | 228                    |
| <b>TOTAL</b>   |                                 | <b>2810</b>            |

**2.3 Northwestern Ontario Island Area**

| <b>Company</b> | <b>Generation Units On-line</b> | <b>Net Output (MW)</b> |
|----------------|---------------------------------|------------------------|
| OH             | Alexander                       | 18                     |
| OH             | Augusabon                       | 0                      |
| OH             | Cameron                         | 16                     |
| OH             | Manitou                         | 13                     |
| OH             | Silver Falls                    | 0                      |
| OH             | Thunder Bay #3                  | 153                    |
| OH             | White Dog                       | 0                      |
| OH             | Kakabeka                        | 0                      |
| OH             | Ear Falls                       | 7                      |
| NUG            | Total NUGs                      | 63                     |
| <b>TOTAL</b>   |                                 | <b>270</b>             |

**Appendix #3 (Continued)****Conditions Prior to the Disturbance****2. Generation on-line (At approximately 02:17 CDT): (Continued)****2.4 In Southern/Eastern MAPP Area (Nebraska/Iowa/Wisconsin)**

| <b>Company</b> | <b>Generation Units<br/>On-Line</b> | <b>Net Output (MW)</b> |
|----------------|-------------------------------------|------------------------|
| BEPC           | Laramie River 1                     | 549                    |
| DPC            | Alma 1 – 5                          | 79.7                   |
| DPC            | Flambeau 3                          | 1.5                    |
| DPC            | Genoa 3                             | 248.0                  |
| DPC            | JPM                                 | 238.3                  |
| IES            | Burlington                          | 96                     |
| IES            | DAEC                                | 507                    |
| IES            | Fair Station 2                      | 38                     |
| IES            | Ottumwa                             | 615                    |
| IES            | Prairie Creek 3 – 4                 | 121                    |
| IES            | Red Cedar                           | 20                     |
| IES            | Sutherland 1 – 3                    | 115                    |
| IPW            | Dubuque 3 – 4                       | 36                     |
| IPW            | Fox Lake 3                          | 18                     |
| IPW            | Kapp 2                              | 183                    |
| IPW            | Lansing 3 – 4                       | 211                    |
| MEC            | Council Bluffs 1 – 3                | 651                    |
| MEC            | Neal 1                              | 105.4                  |
| MEC            | Neal 2                              | 91.7                   |
| MEC            | Neal 3                              | 430                    |
| MEC            | Neal 4                              | 490                    |
| MEC            | Riverside 3, 5                      | 39.3                   |
| MEC            | Waste Mng. 1 & 2                    | 5                      |
| NPPD           | Canaday                             | 81                     |
| NPPD           | Columbus 2 – 3                      | 21                     |
| NPPD           | Cooper                              | 761                    |
| NPPD           | Gentleman 1 – 2                     | 1107                   |
| NPPD           | Jeffrey                             | 16                     |
| NPPD           | Johnson 1                           | 8                      |
| NPPD           | Johnson 2                           | 14                     |
| NPPD           | North Platte 1 – 2                  | 23                     |
| NPPD           | Sheldon 1                           | 72                     |
| OPPD           | Ft. Calhoun                         | 475                    |
| WAPA           | Big Bend 2, 4, 7 (Cond)             | 0                      |
| WAPA           | Ft Randall 2, 7 (1,3-6,8 Cond)      | 84                     |
| WAPA           | Gavins Point 1-3                    | 90                     |
| WAPA           | Oahe 1,2, 4 (Cond)                  | 0                      |
| <b>TOTAL</b>   |                                     | <b>7640.9</b>          |

## Appendix #3 (Continued)

## Conditions Prior to the Disturbance

## 3. Comparison of NSP Unit Generation prior to Prairie-Island Byron 345kV line trip (at 01:34 CDT) and King-Eau Claire 345kV line trip (at 02:18 CDT).

| Generation Units On-line | Net MW at 01:13 CDT | Net MW At 02:17 CDT | Generation Units On-line | Net MW at 01:13 CDT | Net MW at 02:17 CDT |
|--------------------------|---------------------|---------------------|--------------------------|---------------------|---------------------|
| L. S. Power              | 156.4               | Off-line            | Black Dog 4              | 144.3               | 144.1               |
| Cedar Falls 1            | 2.2                 | 2.2                 | High Bridge 6            | 148.9               | 148.6               |
| Cedar Falls 2            | 2.3                 | 2.3                 | Riverside 8              | 224.0               | 224.0               |
| Cedar Falls 3            | 2.4                 | 2.4                 | Prairie Island 2         | 522.0               | 459.3               |
| Bay Front 4              | 9.4                 | 8.9                 | Prairie Island 1         | 502.0               | 502.0               |
| Bay Front 6              | 10.5                | 10.1                | Monticello               | 543.1               | 546.0               |
| Bay Front 5              | 14.2                | 12.5                | Sherco 1                 | 618.2               | 546.9               |
| Riverside 7              | 94.0                | 66.0                | Sherco 2                 | 609.8               | 552.2               |
| Black Dog 3              | 75.8                | 75.6                | Sherco 3                 | 841.0               | 738.0               |
| High Bridge 5            | 78.1                | 77.7                | <b>Totals:</b>           | <b>4598.6</b>       | <b>4118.8</b>       |

## 4. Significant NSP flows prior to Prairie-Island Byron 345kV line trip (at 01:34 CDT) and King-Eau Claire 345kV line trip (at 02:18 CDT).

| NSP Lines/Export                     | Flow (MW/MVAR) at 01:30 CDT | Flow (MW/MVAR) at 02:17 CDT |
|--------------------------------------|-----------------------------|-----------------------------|
| TCEX                                 | 1540.9                      | 1004                        |
| Eau Claire-Arpin 345kV               | 803.0 / 32.6                | 778.9 / 23.9                |
| Byron-Adams 345kV                    | 636.1 / -45.7               | 49.3 / -75.2                |
| Wilmarth-Lakefield Jct. 345kV        | 101.8 / -42.6               | 175.8 / -70.5               |
| Prairie Island-Byron 345kV           | 873.9 / 69.8                | Out of Service              |
| Alma-Rock Elm 161kV                  | 11.8 / 6.1                  | Out of Service              |
| King-Eau Claire 345kV                | 946.8 / 131.6               | 1048.4 / 143.8              |
| Red Rock-Crystal Cave 115kV          | 143.5 / 6.9                 | 175.6 / 11.5                |
| Pine Lake-Wissota 115kV              | 50.3 / -28.9                | 56.7 / -34.4                |
| Pine Lake-Apple R/Crystal Cave 161kV | 32.8 / -16.0                | 44.8 / -18.1                |
| South Faribault-West Owatonna 161kV  | 38.3 / -11.6                | 113.9 / -52.1               |
| Ironwood-Park Falls 115kV            | 29.8 / -7.0                 | 25.0 / -6.7                 |
| Split Rock-White 345kV               | -346.8 / 25.5               | -332.3 / 21.1               |
| Pathfinder-Split Rock 115kV          | 1.3 / 7.0                   | 8.9 / 0.7                   |
| Wilmarth-Winnebago 161kV             | 90.6 / -10.0                | 128.9 / -12.9               |

## Appendix #4

## TCEX, NDEX, and MHEX Definitions

## Twin Cities 345kV Export Ties (TCEX)

| <u>Terminal A</u> |           | <u>Terminal B</u> |       |
|-------------------|-----------|-------------------|-------|
| Eau Claire        | --->----- | Arpin             | 345kV |
| Byron             | --->----- | Adams             | 345kV |
| Wilmarth          | --->----- | Lakefield         | 345kV |

## North Dakota Export Ties (NDEX)

| <u>Terminal A</u> |            | <u>Terminal B</u> |       |
|-------------------|------------|-------------------|-------|
| Leland Olds       | ----->--   | Ft. Thompson      | 345kV |
| Leland Olds       | ----->--   | Groton            | 345kV |
| Antelope Valley   | ----->--   | Huron             | 345kV |
| Sully Butte       | ----->--   | Oahe              | 230kV |
| Bison             | ----->--   | Maurine           | 230kV |
| Big Stone         | ----->--   | Blair             | 230kV |
| Morris            | ----->--   | Granite Falls     | 230kV |
| Sheyenne          | --- >----- | Hubbard           | 230kV |
|                   | Audubon    |                   |       |
| Inman             | --->-----  | Wing River        | 230kV |
| Ellendale         | --->-----  | Aberdeen Jct.     | 115kV |
| Edgeley           | --->-----  | Ordway            | 115kV |
| Forman            | --->-----  | Summit            | 115kV |
| Canby             | ----->--   | Granite Falls     | 115kV |
| Alexandria        | ----->--   | Douglas Co.       | 115kV |
| Laporte           | ----->--   | Badoura           | 115kV |
| Kerkhoven         | --->-----  | Kerkhoven Tap     | 115kV |
| Drayton           | ----->--   | Letellier         | 230kV |

## Manitoba Hydro Export (MHEX)

| <u>Terminal A</u> |               | <u>Terminal B</u> |       |
|-------------------|---------------|-------------------|-------|
| Dorsey            | --->--- ----- | Forbes            | 500kV |
|                   | Roseau        |                   |       |
| Letellier         | --->-----     | Drayton           | 230kV |
| Richer            | --->-----     | Roseau            | 230kV |

NOTE: Positive flow from terminal A to terminal B means power is leaving an area on a given line. The arrow symbol indicates the location that the flow is measured. A positive measurement is obtained if the real power is flowing in the direction of the arrow symbol.



## Appendix #5

## Sequence of Events

## Northern MAPP/Northwestern Ontario Disturbance - June 25, 1998 @ 02:18CDT

| Time (CDT)                 | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
|----------------------------|-------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 06/24/98<br>23:24          | MAPP<br>(MCN)     | ALT / Requested NERC TLR on the Eau Claire-Arpin 345kV line. The line loading is 786 MW and the alarm limit is 725 MW (based on the operating guides).<br><br>Note: The 725 MW alarm is the recommended off-peak flow limit identified in the "Minnesota-Eastern Wisconsin Phase Angle Reduction Guide (August 15, 1997)". This pre-contingent operating limit is intended to protect eastern Wisconsin area by preventing an excessive post-contingent phase angle for reclosing the Eau Claire-Arpin 345kV line. No requests for curtailments were made, as only a schedule collection took place. |
| 06/25/98<br>prior to event | NSP               | King Generating Unit - Off-Line<br>(Prior outage)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| 06/25/98<br>prior to event | NSP               | Lake Marion - West Faribault 115kV Line<br>Carver County - Glendale - Scott County 115kV Line<br>Elm Creek - West Coon Rapids 115kV Line<br>(Prior outages) Maintenance.                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 01:13                      | NSP               | Prairie Island unit #2 at 522 MW                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 01:14                      | MP                | Badoura 40L, 48L, 725L (Note: 725L line is the Badoura-Bemidji 115kV line), 64L and 2TM OPEN by relay. Failed CCPD on 725 line                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 01:14:54                   | OTP               | Bemidji CB 1245 tripped and reclosed auto. Cass Lake load off until restored by dispatcher at 01:15 and 01:18                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| 01:15                      | Exports           | NDEX=1501 MW, MHEX=1681 MW, TCEX=1578 MW<br>(Byron-Adams=650 MW, Wilmarth-Lakefield=106 MW, Eau Claire-Arpin 345kV=822 MW)                                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
| 01:19:12                   | NSP               | Open - Lafayette - Schilling 69kV                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| 01:34:19.616               | NSP               | Prairie Island - Byron 345kV line trips (NSP shows at 1:34:23, DPC shows at 01:34:30, MP shows at 01:34:19.616)<br>Phase A to ground fault recorded and tripping was proper. There is no instantaneous reclose on this line. Line could not be reclosed manually due to greater than 40 degree phase angle across the open line.                                                                                                                                                                                                                                                                     |
| 01:34:19:618               | UPA               | Dickinson 345 CU HVDC pole 2 commutation failure                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 01:34:35.348               | NSP               | Prairie Island-Byron 345kV line auto recloses properly (Prairie Island breaker 8H9 reclosed on hot bus/dead line) at Prairie Island. The line was open at the Byron end. About 8 cycles later, a Phase A to ground fault was detected, and the line tripped back out 2-1/2 cycles later. (NSP shows at 01:34:39)                                                                                                                                                                                                                                                                                     |
| 01:35 (approx.)            | NSP               | Byron breaker 8S14 recloses properly (hot bus/dead line) energizing the open-ended Prairie Island-Byron 345kV line, and remains closed. The line was open at the Prairie Island end.                                                                                                                                                                                                                                                                                                                                                                                                                 |

| Time (CDT)   | Reporting Company       | Event                                                                                                                                                                                                                                                                                                                                           |
|--------------|-------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 01:36:00     | NSP                     | Open - Cannon Falls - Spring Creek 69kV, Cannon Falls - Northfield 69kV, and Cannon Falls - Zumbrota 69kV lines.                                                                                                                                                                                                                                |
| 01:36:10     | UPA                     | Rush City 69 9NB2 Trip Rush City-Blaine 69kV Tripped and Reclosed auto at 1:36:13                                                                                                                                                                                                                                                               |
| 01:36:10     | UPA                     | Blaine 69 23NB4 Rush City-Blaine 69kV Tripped and reclosed auto at 1:36:16                                                                                                                                                                                                                                                                      |
| 01:37:51     | NSP                     | Operator attempts to manually close Prairie Island-Byron 345kV line at Prairie Island (8H9). Unsuccessful due to high phase angle.                                                                                                                                                                                                              |
| 01:38:36     | NSP                     | Operator manually opens breaker at Byron (8S14) on Prairie Island-Byron 345kV line, de-energizing the open-ended line.                                                                                                                                                                                                                          |
| 01:39        | MAPP (MCN)              | NSP / PRI-BYN 345KV TRIPPED @ 0134. REMAINS OPEN.                                                                                                                                                                                                                                                                                               |
| 01:39:23     | NSP                     | Operator manually closes breaker at Prairie Island (8H9) on Prairie Island-Byron 345kV line. Prairie Island breaker (8H8) also manually closed at 01:39:27. The line is energized, but open-ended at the Byron end.                                                                                                                             |
| 01:41        | MAPP (MCN)              | SMP / BYN-ADM 345KV TRIPPED @ 0133 & RECLOSED AUTO. (Note: Alliant-IPW later indicated that Adams CB 8S2 did not actually trip on or around 01:33.)                                                                                                                                                                                             |
| 01:41:28     | NSP                     | Operator attempts to manually close Prairie Island-Byron 345kV line at Byron (8S15). Unsuccessful due to high phase angle. Approximately 7 minutes have elapsed since the line tripped at 01:34.                                                                                                                                                |
| 01:45        | Exports                 | NDEX=1448 MW, MHEX=1578 MW, TCEX=1062 MW<br>(Byron-Adams=64 MW, Wilmarth-Lakefield=180 MW, Eau Claire-Arpin 345kV=818 MW)                                                                                                                                                                                                                       |
| 01:51        | MAPP (MCN)<br><br>(LLR) | NSP / REQUESTING 50 MWS LLR ON ECL-ARP 345KV DUE TO PRI-BYN 345KV OUT. REDUCED 246 MWS PRI '1' SCHEDULES FOR RELIEF. POSTED. LOCKED. MASTER RUN #12552.<br><br>Note: NSP calls LLR in the line Eau Claire-Arpin 345kV. They request curtailments of 50 MW. Conditions on that line reported by NSP are: Load Level: 830 MW, Load limit : 800 MW |
| 01:54        | MAPP<br><br>(LLR)       | Note: The message for the 50 MW relief on the Eau Claire-Arpin 345kV line is broadcast on the MCN. The curtailments will take place ASAP or across 02:00.<br>(MAPP shows that the requested curtailments took place on time or before the tripping of King-Eau Claire 345kV line)                                                               |
| 01:59:10     | UPA                     | Crow River 69 4M62 Mpl Lk-Crw Rvr-Hutch 69kV Tripped and reclosed auto at 1:59:18                                                                                                                                                                                                                                                               |
| 01:59:10     | UPA                     | Hutchinson 69 C3NB2 Mpl Lk-Crw Rvr-Hutch 69kV Tripped and reclosed auto at 1:59:14                                                                                                                                                                                                                                                              |
| 01:59:10     | UPA                     | Maple Lake 69 1NB2 Mpl Lk-Crw Rvr-Hutch 69kV Tripped and reclosed auto at 1:59:17                                                                                                                                                                                                                                                               |
| 02:00:10     | DPC                     | Alma-Rock Elm 69kV relayed to lockout                                                                                                                                                                                                                                                                                                           |
| 02:01:40     | DPC                     | Alma - Rock Elm 161kV Open (Storm damage, 5 structures down) Relayed to Lockout. (NSP shows at 02:01:33) Line returned to service on 6/27/98 at 14:54.                                                                                                                                                                                          |
| 02:02:31:282 | UPA                     | Coal Creek 230 CU HVDC P1 and P2 Line Protection and restart                                                                                                                                                                                                                                                                                    |
| 02:08:07     | DPC                     | Alma-Rock Elm 69kV line restored.                                                                                                                                                                                                                                                                                                               |
| 02:10        | MAPP (MCN)              | NSP(R) / CAN'T CLOSE PRI-BYN DUE TO PHASE ANGLE. WOULD LIKE 100 MWS LLR ON PRI-BYN TO REDUCE PHASE ANGLE. POSTED. LOCKED. MASTER RUN # 12558.                                                                                                                                                                                                   |

| Time (CDT)           | Reporting Company    | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
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|                      | <b>(LLR)</b>         |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| 02:11                | MAPP<br><b>(LLR)</b> | Note: NSP calls 100 MW LLR in the interface Prairie Island- Byron. The line is open at this time. The start time for the curtailments is 02:30                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 02:15                | Exports              | NDEX=1297 MW, MHEX=1253 MW, TCEX=1004 MW<br>(Byron-Adams=51 MW, Wilmarth-Lakefield=178 MW, Eau Claire-Arpin 345kV=775 MW)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 02:17                | NSP                  | Prairie Island unit #2 at 459 MW (63 MW reduction since 01:13) NSP lowering generator output to attempt to reduce Prairie Island-Byron 345kV phase angle.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 02:18:18.093         | NSP                  | <p><b>King - Eau Claire 345kV line trips.</b> Phase A, SLG fault, relay operation appears proper.</p> <p><b>THIS EVENT BEGINS THE CASCADE THAT EVENTUALLY SEPARATES NORTHERN MAPP AND RESULTS IN THE FORMATION OF SEVERAL ISLANDS.</b></p> <p>With two major Twin Cities 345kV outlets out of service, the remaining tie (Blue Lake – Wilmarth 345kV) and the underlying system on the Minnesota – Wisconsin interface are heavily stressed. The frequency oscillations after the line trip were positively damped and decayed quickly. (NSP shows at 02:18:18, DPC shows at 02:18:44, MP shows at 02:18:18.093)</p> <p>Beginning at this time and lasting approximately 20 minutes, the Alma 161kV bus voltage was unstable and varying between 156kV to 168kV, and the JPM unit reactive output was varying between 160Mvar to -55Mvar.</p> <p>Between 2:18 and 2:25 AM, a total of 14 NSP distribution feeders at Menomonie, Bayfront, Ironwood, Rice Lake, T-Corners, and Cumberland in western Wisconsin tripped on undervoltage.</p> |
| 02:18                | MH                   | Unusual "circulating flow" observed on MH-US ties: Dorsey-Forbes 500kV (D602F) south flow <u>decreases</u> from 922 MW to 793 MW, Lettelier-Drayton 230kV (L20D) south flow <u>increases</u> from 171 MW to 229 MW, Richer-Moranville 230kV (R50M) no significant change. MH-OH tie Kenora-Whiteshell 230kV (K21W) east flow increases from 114 MW to 169 MW                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 02:18:00 to 02:18:18 | OH                   | Whiteshell Phase Shifter had maintained 120 MW schedule from MH to OH and International Falls PSTs with 90 MW schedule from MP to OH. Flows into Northwestern (NW) Ontario were within operating limits.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| 02:18:20             | IPW                  | Trip CB 657 Montgomery - New Prague 69KV zone 3 $\phi$                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 02:18:22             | NSP                  | <b>Eau Claire - Arpin 345kV Open (Cross-Trip from King-Eau Claire 345kV)</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 02:18:22             | NSP                  | Afton - Red Rock 115kV Open                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| 02:18:22             | NSP                  | Red Rock - Crystal Cave 115kV Open (Phase distance, zone 2 trip)<br>Note: The frequency oscillations after the line trip were positively damped and decayed quickly.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:18:34             | MP                   | LSPI 10K Capacitor Bank CLOSED                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 02:19:00             | OH                   | Kenora-Whiteshell 230kV (K21W) and International Falls-Fort Frances                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |

| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
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|              |                   | Phase Shifter (F3M) loading increased and off the schedule. OH requested MP to return F3M flow north back to 90 MW schedule. MP reported they were having some problems on their system but would ramp back to 90 MW ASAP.                                                                                                                                                                                                                                                                    |
| 02:19:28     | DPC               | NSP Bayfront and Ironwood 34.5kV feeders tripped shedding the Bayfield, Barsdale, Highbridge, Kimball, Ironbelt, and Morse DPC substations. 58 minute customer outage on Bayfield, 40 minute customer outage on the remaining substations.                                                                                                                                                                                                                                                    |
| 02:19:59     | MAPP<br>(LLR)     | Note: The message for the 100 MW relief in the Prairie Island-Byron interface is sent out through the MCN. The curtailments should take place ASAP, not later than 02:30. NO schedules are specifically identified for reduction. No schedule cuts are made.                                                                                                                                                                                                                                  |
| 02:20:01     | NSP               | Pine Lake - Wissota 115kV Open (Timed Overcurrent)                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| 02:20:08     | DPC               | Crystal Cave-Apple River 161kV line tripped and the Apple River 69kV bus cleared. (NSP shows at 02:25:42 when Apple River RTU communications were restored.)                                                                                                                                                                                                                                                                                                                                  |
| 02:20:46     | NSP               | Pine Lake - Apple River/Crystal Cave 161kV Open (Timed Overcurrent)                                                                                                                                                                                                                                                                                                                                                                                                                           |
| 02:20:52     | DPC               | Alma 4NB11 (69kV to Red Wing) tripped and did not reclose                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 02:21:22     | MAPP<br>(MCN)     | NSP / ASK-ECL-ARP TRIPPED. NSP IS SUSPENDING FERC 888/889 DUE TO LOSS OF 345KV INTERCONNECTIONS. (MCN message from NSPM to BC)                                                                                                                                                                                                                                                                                                                                                                |
| 02:21:24:280 | MP                | <b>Stinson – Minong 161kV line trips</b> (Stinson CB 6T opened by time overcurrent relay).<br><br>This line trip continues the cascade tripping of the Minnesota - Wisconsin ties which separates Minnesota from Northwest Wisconsin. <b>The Stinson-Ironwood-Park Falls 115kV line is the only tie to Northwest Wisconsin remaining at this point.</b> (NSP shows 2:21:26)<br><br>The remaining ties from the Twin Cities to the south, and those to Northwest Ontario are further stressed. |
| 02:21:24     | MH                | Another change in tie flows accompanied by oscillations.: D602F decreases further to approx. 647 MW, L20D increases to approx., 330 MW, K21W increases to approx. 250 MW. Note: only one MH-OH tie was in-service.                                                                                                                                                                                                                                                                            |
| 02:21:26     | DPC               | Barron 16NB4 (69kV to Pine Lake) tripped and did not reclose                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 02:21:27     | NSP               | South Faribault - West Owatonna 161kV Open                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| 02:21:28     | MP                | Little Fork 20K and 21K CLOSED                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| 02:21:28     | OH                | Kenora bus voltage dropped from 234 to 218kV and Fort Frances from 119 to 110kV.                                                                                                                                                                                                                                                                                                                                                                                                              |
| 02:21:28.464 | WAPA              | Spencer PCB 1242 trips (phase distance, zone 3) – opening 161/69kV interconnection                                                                                                                                                                                                                                                                                                                                                                                                            |
| 02:21:29     | NSP               | Cedar Falls generation (6.9 MW) trips (restored at 02:26:25).                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:21:30     | IPW               | Trip CB 660 Hayward to Winnebago 161kV zone 3φ                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| 02:21:31     | IPW               | Trip CB 775 Fox Lake to Winnebago 161kV zone 2φ<br><br><b>All ties south between NSP system and Iowa are now tripped except for Wilmarth-Lakefield 345kV line and the Wilmarth-Winnebago 161kV line which is only interconnected through the Winnco 69kV underlying system.</b>                                                                                                                                                                                                               |

| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
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| 02:21:31     | NSP               | <b>Ironwood – Park Falls 115kV Trips (Overload)</b><br><br><b>Minnesota separated from Northwest Wisconsin (all Twin Cities east ties tripped).</b>                                                                                                                                                                                                                                                                                                                                 |
| 02:21:32     | IPW               | Trip CB 620 Albert Lea Westside to Walters 69kV zone 2 $\phi$                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:21:46     | MP                | Stinson 10K Capacitor Bank OPEN                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 02:21:52     | OH                | Largest power surge recorded on Kenora-Whiteshell 230kV line (K21W) (244 MW) @t=02:21:52. Largest surge on International Falls-Ft Francis Phase Shifter (F3M) (174 MW) was recorded @t=02:21:38. Both MH>OH and MP>OH tie flows exceeded operating limits.                                                                                                                                                                                                                          |
| 02:21:54:880 | MP                | <b>Manitoba – Ontario 230kV (K21W) tie trips</b> by overcurrent protection. This line trip correctly initiated a MH DC reduction (265 MW). <b>(SPS OPERATION)</b>                                                                                                                                                                                                                                                                                                                   |
| 02:21:55.147 | MP                | <b>International Falls-Ft Francis Phase Shifter (F3M) tie between Minnesota Power and Ontario trips</b> by out-of-step protection in response to the Kenora-Whiteshell 230kV line (K21W) trip.<br><br>The NW Ontario East-West Ties (Wawa-Marathon 230kV Line #1 and #2) trip in response to K21W and F3M trips. (See OH 02:22:04 event)<br><br><b>NW Ontario separated from Manitoba and Minnesota.</b>                                                                            |
| 02:21:55     | MP                | Little Fork 22K Capacitor Bank CLOSED                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 02:21:56     | MH                | Frequency starts to increase and Dorsey frequency damping controller reacts by gradually decreasing MH DC power. (Approximately a 300 MW reduction over a 1 second timeframe)                                                                                                                                                                                                                                                                                                       |
| 02:21:56     | MP                | Little Fork 20K,21K,22K and 25K Capacitor Banks OPEN                                                                                                                                                                                                                                                                                                                                                                                                                                |
| 02:21:56.922 | NSP               | <b>Wilmarth – Lakefield 345kV line trips</b><br><br>(Tripped on zone 2 primary and secondary phase distance relays. IPW reported "out of step" targets and timers. This combination of targets is consistent with a trip for an out of step condition.)<br><br>The cascade tripping of the remaining Minnesota and North Dakota ties to the south commences. Minnesota, Manitoba, and North Dakota are ultimately islanded together. (NSP shows 02:21:57, MP shows at 02:21:56.922) |
| 02:21:56.948 | WAPA              | Ft Thompson terminal of Leland Olds-Ft Thompson 345kV line opens, open ending the line, no automatic reclose. PCB's 2992 and 2996 tripped (phase distance, zone 1)                                                                                                                                                                                                                                                                                                                  |
| 02:21:57.160 | WAPA              | White terminal of White-Split Rock 345kV line opens. PCB's 396 and 492 tripped (phase distance, zone 1)                                                                                                                                                                                                                                                                                                                                                                             |
| 02:21:57.177 | WAPA              | Split Rock terminal of White-Split Rock 345kV line also opens, de-energizing line, no automatic reclose. PCB's 196 and 192 tripped (target unknown) (NSP shows 02:21:59)                                                                                                                                                                                                                                                                                                            |
| 02:21:57.186 | WAPA              | Bismarck terminal of Bismarck-Glenham 230kV line opens, open ending the line. PCB 582 tripped (phase distance, zone 1 and 2). Glenham PCB 382 tripped at 02:21:57:375 at which time the line was already de-energized. (MDU shows 02:21:57:383 for PCB 382 trip). Glenham PCB 382 was closed at 02:21:58:069 at which time the line was still de-energized from both ends. (MDU shows 02:21:58:081 for PCB 382 close).                                                              |
| 02:21:57.246 | WAPA              | Ft Randall units 1-6 and 8 tripped. Units 1 and 7 were loaded at 42 MW each prior to disturbance. Remaining units were condensing.                                                                                                                                                                                                                                                                                                                                                  |

| Time (CDT)      | Reporting Company | Event                                                                                                                                                                                                                                                                                    |
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|                 |                   | Unit 1 tripped during disturbance resulted in 42 MW loss. Unit #1 back on-line approx. 03:57.                                                                                                                                                                                            |
| 02:21:57.249    | WAPA              | Ft Thompson terminal of Ft Thompson-Huron #2 230kV line opens, open ending the line. PCB 786 tripped (phase distance, zone 1)                                                                                                                                                            |
| 02:21:57.250    | WAPA              | Glenham terminal of Glenham-Sully Buttes 230kV line opens, open ending the line, de-energizing Glenham substation and associated customer loads. PCB 282 tripped (phase distance, zone 1) (MDU shows 02:21:57:256)                                                                       |
| 02:21:57.255    | WAPA              | Ft Thompson terminal of Ft Thompson-Huron #1 230kV line opens, open ending the line. PCB's 586 and 582 tripped (phase distance, zone 1)                                                                                                                                                  |
| 02:21:57.264    | WAPA              | Huron terminal of Ft Thompson-Huron #2 230kV line opens, de-energizing line, no automatic reclose. PCB's 786 and 782 tripped (phase distance, zone 1).                                                                                                                                   |
| 02:21:57.266    | WAPA              | Huron terminal of Huron-Storla 115kV line opens, open ending the line. PCB 1362 tripped (phase distance, zone 1)                                                                                                                                                                         |
| 02:21:57.266    | WAPA              | Huron terminal of Ft Thompson-Huron #1 230kV line opens, de-energizing line, no automatic reclose. PCB's 582 and 586 tripped (phase distance, zone 1)                                                                                                                                    |
| 02:21:57.282    | WAPA              | Brookings terminal of Brookings-Flandreau 115kV line opens, open ending the line, no automatic reclose. PCB 1862 tripped (phase distance, zone 1)                                                                                                                                        |
| 02:21:57.293    | WAPA              | Maurine terminal of Maurine-Hettinger 230kV line opens, open ending the line, no automatic reclose. PCB's 282 and 582 tripped (phase distance, zone 1)                                                                                                                                   |
| 02:21:57.331    | WAPA              | Hettinger terminal of Maurine-Hettinger 230kV line also opens, de-energizing line, momentarily de-energizing Bison substation and associated customer load, automatic reclose. PCB's 282 and 186 tripped (phase distance, zone 1) (MDU shows 02:21:57:332 and 02:21:57:334 respectively) |
| 02:21:57.486    | MH                | D602F MH DC reduction (40% = 340 MW) received at Dorsey from Forbes. Forbes DCAR relay operated in response to system swings. <b>(SPS OPERATION)</b>                                                                                                                                     |
| 02:21:57.839    | WAPA              | Hettinger terminal of Hettinger-Maurine 230kV line re-closes, re-energizing open ended Hettinger-Bison-Maurine 230kV line, restoring service to Bison substation. PCB 282 reclosed. (MDU shows 02:21:57:845)                                                                             |
| 02:21 (approx.) | OTP               | Wahpeton CB 215 tripped on under-voltage. Load restored at 03:15                                                                                                                                                                                                                         |
| 02:21 (approx.) | OTP               | Toronto CB 515 tripped on under-voltage. Load restored at 03:17                                                                                                                                                                                                                          |
| 02:21 (approx.) | OTP               | Big Stone Hwy 12 CS 1211 opened on under voltage. Load restored at 03:14.                                                                                                                                                                                                                |
| 02:21 (approx.) | OTP               | Marsh Lake CB 475 tripped. Loads restored at 03:18                                                                                                                                                                                                                                       |
| 02:21:57        | NSP               | Buffalo Ridge - Pipestone 115kV Open                                                                                                                                                                                                                                                     |
| 02:21:58        | MEC               | Neal unit #4 tripped (Load level=490 MW) (Generator distance protection). Back on-line at 08:41 and at full load at 15:00.                                                                                                                                                               |
| 02:21:58        | DPC               | Twin Lakes-Winnco 69kV tripped and remained open-ended at Winnco (34NB9) for 5-1/2 minutes.                                                                                                                                                                                              |
| 02:21:58        | MH                | Frequency reaches 60.8 Hz blocking Bipole 2 valve groups 31 and 42 by overfrequency protection, resulting in 250 MW dc power decrease                                                                                                                                                    |
| 02:21:58        | MH                | Frequency stabilizes at 61.0 Hz and Bipole 1 valve groups 12 and 23 block by overfrequency protection. No significant power change on Bipole 1 as remaining valve groups compensate                                                                                                      |
| 02:21:58        | MP                | Winton Generator 2U OPEN by relay                                                                                                                                                                                                                                                        |

| Time (CDT)      | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
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| 02:22:00        | IPW               | Trip CB 862 Dotson to Rutland 69kV zone 1φ<br>Trip CB 711 Rutland to Dotson 69kV zone 1φ                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:22:01        | IPW               | Trip CB 007 Emery to Franklin 161kV (zone 2 carrier) (unrelated to disturbance)<br>Trip CB 773 Fox Lake to Lakefield 161kV (zone 2φ)<br>Trip CB 737 Fox Lake 161/69 Transformer (time overcurrent)<br>Open Lakefield-Wilmarth 345kV (out of step)<br>Open Lakefield-Raun 345kV (out of step)<br>Open Lakefield 345/161kV transformer (out of step)<br><br>The Raun-Ft Calhoun 345kV line opens 75msec after Lakefield-Raun 345kV line (out of step)<br><br>Lakefield-Triboji (Wisdom) 161kV line flows: 123 MW @02:16, 196 MW @02:21, 240 MW @02:22, and -25 MW @02:22:30 after Wilmarth-Lakefield-Raun 345kV line trips.<br><br>Cedar Falls Streeter unit #7 tripped (Loss of field protection)                                                                                                                                                               |
| 02:22 (approx.) | NPPD              | Disturbance in Northern MAPP area which resulted in loss of load and voltage and frequency oscillations on NPPD's system                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:22:01        | NSP               | Buffalo Ridge - Pipestone 115kV automatically reclosed                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
| 02:22:01        | NWPS              | Mitchell PCB 2731 to Huron 115kV opened, did not Reclose.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| 02:22:01        | NWPS              | Redfield PCB 4704 to Huron 115kV opened and reclosed.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| 02:22:01.799    | MDU               | HETTINGER 230KV JCT. SUB.<br>230KV PCB #186 RING BUS<br>CLOSED -- Restore ring bus (Hettinger-Maurine already energized)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:22:02.406    | MDU               | ELLENDAL 230KV JCT. SUB.<br>14KV PCB #5137 REACTOR OPEN                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| 02:22:02        | MP                | Knife Falls Generators 1U, 2U 3U OPEN by relay                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:22:03        | NSP               | Pathfinder - Split Rock 115kV Open                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 02:22:04        | OH                | East-West ties (Wawa-Marathon 230kV Line #1 and #2, designated as W21M and W22M) tripped. Prior to the trips, the East-West ties were left supplying the NW system, which was deficient by about 360 MW. Due to large power surge on W21W+W22M into the NW Ontario following the loss of K21W + F3M, Marathon voltage was brought down to 17% (i.e. from 175kV to 40kV in ½ second) and the current on W22M to about 940 amps. W22M was tripped by line protection, then W21M tripped 4.5 cycles later. Thunder Bay G3 (thermal unit) tripped on under-frequency protection. FTR load shedding triggered. At this time, the NW system collapsed and was shut down with the exception of a 20 MW island containing Ear Fall GS, Manitou GS, Red Lake TS and Ear Falls DS.<br><br><b>NW Ontario ISLAND (blackout) formed. Approximately 650 MW of load lost.</b> |
| 02:22:06        | IPW               | Close CB 862 Dotson to Rutland 69kV<br>Close CB 711 Rutland to Dotson 69kV (Auto reclose)<br>Trip CB 710 Rutland 161/69 Transformer (Reason unknown)<br>Trip CB 712 Rutland to Fairmont 69kV zone 1φ                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
| 02:22:09.434    | MDU               | ELLENDAL 230KV JCT. SUB.<br>14KV PCB #5137 REACTOR CLOSE                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:22:09        | NSP               | <b>Open - Wilmarth - Winnebago 161kV Line</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |

| Time (CDT)         | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                            |
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|                    |                   | <p>Minnesota/Manitoba/North Dakota/Saskatchewan (MN-MH-ND-SASK) ISLAND is formed.</p> <p>The frequency of the island increases almost immediately to 60.9 Hz, then drops to 60.7 Hz over the next 13 seconds (appears due primarily to Poplar River #2 unit trip), and then ramps to 61.1 Hz over the next approx. 2-1/2 minutes.</p>            |
| 02:22:10           | MP                | International Falls 726L OPEN by out of step relay, (MP-Ontario Tie)                                                                                                                                                                                                                                                                             |
| 02:22:10           | OTP               | Hoot Lake #3 tripped on low load while following frequency excursions. Output was 18 MW before trip. Unit returned at 04:45                                                                                                                                                                                                                      |
| 02:22:11           | NSP               | Open Pine Lake - Rock Elm 69kV                                                                                                                                                                                                                                                                                                                   |
| 02:22:12           | NSP               | Open T-Corners - Wien 115kV (Over-current trip)                                                                                                                                                                                                                                                                                                  |
| 02:22:12           | MP                | International Falls 11K Capacitor Bank OPEN<br>LSPI 10K Capacitor Bank OPEN                                                                                                                                                                                                                                                                      |
| 02:22:13           | IPW               | Fox Lake G3 (88MVA rating) tripped at 2:22 with 18 MW of output on over-excitation. The reactive output went from 7MVAR at 2:18:00 to 58MVAR at 2:18:30. Lansing G4 (274MVA rating) increased reactive output from 9MVAR at 2:17:00 to 44MVAR at 2:21:30 with a real power output of 185 MW.                                                     |
| 02:22:13 (approx.) | SPC               | The SaskPower frequency increased rapidly to 60.85 Hz. This caused intercept valves to operate on the 300 MW Poplar River #2 thermal unit. The unit tripped off line due to cold reheat steam pressure. SaskPower frequency continued to increase subsequent to the unit trip. The maximum frequency observed was 61.05 Hz. at approx. 02:24:57. |
| 02:22:32           | NSP               | Open Red Wing - Alma 69kV (out due to storm damage)<br>Open Pine Lake - Barron 69kV restoration at 2:34:55                                                                                                                                                                                                                                       |
| 02:22:35           | MEC               | Neal unit #3 tripped (430 MW) on Volt/Hz protection. Unit back on-line at 04:37, reached full load at 10:00.                                                                                                                                                                                                                                     |
| 02:22:35           | NSP               | Riverside unit #7 tripped (66 MW)                                                                                                                                                                                                                                                                                                                |
| 02:22:40           | NSP               | Open Stone Lake - Bayfront 69kV                                                                                                                                                                                                                                                                                                                  |
| 02:22:42           | IPW               | Open Mt Lake 69kV, 5.4MVAR Capacitor Bank (Overvoltage trip)                                                                                                                                                                                                                                                                                     |
| 02:22:48           | MP                | Forbes 20K OPEN ( 90 I initiate) Capacitor Bank                                                                                                                                                                                                                                                                                                  |
| 02:22:51.496       | WAPA              | Tioga 230/115kV transformer 230kV terminal opens, open ending transformer. PCB's 782 and 882 tripped (Reverse Power Flow)                                                                                                                                                                                                                        |
| 02:22:53           | UPA               | Dickinson 345 62JSM3 Dickinson 114 MVAR shunt bank<br>Manually tripped for voltage control                                                                                                                                                                                                                                                       |
| 02:22:58           | MP                | Brainerd 2K OPEN                                                                                                                                                                                                                                                                                                                                 |
| 02:23:02           | MEC               | Neal unit #2 tripped (92 MW) on Volt/Hz protection. Unit back on-line at 06:56, reached full load at 11:00.                                                                                                                                                                                                                                      |
| 02:23:35           | MAPP (MCN)        | NSP IS SUSPENDING FERC 888/889 DUE TO LOSS OF 345KV INTERCONNECTIONS. (MCN message from NSPM to BC)                                                                                                                                                                                                                                              |
| 02:24:17           | UPA               | Grasston 69 15NB1 Grasston-Cambridge 69kV Tripped and reclosed auto at 2:24:23                                                                                                                                                                                                                                                                   |
| 02:24:17           | UPA               | Cambridge 69 2NB4 Grasston-Cambridge 69kV Tripped and reclosed auto at 2:24:25                                                                                                                                                                                                                                                                   |
| 02:24:31           | MP                | Unknown event causes significant frequency excursions.                                                                                                                                                                                                                                                                                           |
| 02:24:51.041       | NSP               | Sherco Unit 3 trips (738 MW) (NSP shows at 02:24:58, MP shows at 02:24:51.041)                                                                                                                                                                                                                                                                   |
|                    |                   | <b>MN-MH-ND-SASK ISLAND frequency drops quickly from 61.1 Hz</b>                                                                                                                                                                                                                                                                                 |



| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
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|              |                   | <b>due to unit trip and stabilizes at 60.8 Hz.</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| 02:25        | MH                | Flow on D602F steps from 150 MW north to 30 MW north then to 100 MW south. L20D steps from 30 MW north to 120 MW north.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:25:14.204 | UPA               | <b>CU HVDC Pole 1 manually tripped</b><br><br>Dickinson 345 62JB1,62JB2 CU HVDC Pole 1 manually tripped (MP shows at 02:25:14.360)<br>Coal Creek 230 61RB1,61RB2 CU HVDC Pole 1 manually tripped at 02:25:14.282<br><br><b>MN-MH-ND-SASK ISLAND frequency drops slightly.</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
| 02:25:42.042 | UPA               | <b>CU HVDC Pole 2 trips</b><br><br>Coal Creek 230 61RB5,61RB6 CU HVDC Pole 2 trip on voltage stress protection at Coal Creek at 02:25:42.042<br>Dickinson 345 62JB5,62JB6 CU HVDC Pole 2 trip on voltage stress protection at Coal Creek at 02:25:42.111 (MP shows at 02:25:42.036)<br><br><b>At this point the Minnesota/Manitoba/Saskatchewan and North Dakota frequencies start to diverge and the separation of North Dakota from Minnesota/Manitoba/Saskatchewan commences.</b><br><br><b>Following the separation of ND from MN/MH/SASK there was a 0.15 Hz oscillation of the frequency in the ND system. This was a poorly damped oscillation with an amplitude of +/- 0.5 Hz which lasted for 31.5 seconds until 02:26:16.</b> |
| 02:25:42.161 | UPA               | Coal Creek 230 61RB3 CCS Unit 2 Unit 2 trip for loss of HVDC<br><br>Note: CCS Unit 1 remained on-line on the AC system (370 MW net)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 02:25:42     | MH                | L20D steps from 120 north to 300 north and Letellier voltage declines to 0.75 pu.<br><br><b>Letellier-Drayton 230kV (L20D) trips (Out of step protection).</b><br><br>No MH DC reduction as flow north (correct response).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| 02:25:42.33  | UPA               | Ramsey 230 33RB3 Cap Bank 1 Automatically closed                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| 02:25:42.50  | UPA               | Ramsey 230 33RB4 Cap Bank 2 Automatically closed                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| 02:25:42.684 | UPA               | Coal Creek 230 61RSM2 CC High Pass Filter 1 Auto trip for loss of HVDC                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 02:25:42.684 | UPA               | Coal Creek 230 61RSM4 CC High Pass Filter 2 Auto trip for loss of HVDC                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 02:25:42.951 | WAPA              | <b>Tioga 230kV breaker opens, open ending the Tioga-Boundary Dam 230kV (B10T) line, and the Tioga-Logan 230kV line). PCB 786 tripped (out of step protection).</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| 02:25:43.037 | SPC               | Boundary Dam-Tioga (B10T) line tripped at Boundary Dam by direct transfer trip signal from Tioga. Suspected operation of the out of step relaying at Tioga. Impedance relaying at Boundary Dam end of B10T started but did not issue a trip signal. The SaskPower frequency dropped to 59.65 Hz immediately after the B10T trip occurred. Frequency returned to 60 Hz by approx. 02:26:05.                                                                                                                                                                                                                                                                                                                                              |
| 02:25:43.233 | WAPA              | Open-Ended Tioga-Boundary Dam 230kV (B10T) line energized from the Tioga end. PCB 882 closed manually via SCADA.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |

| Time (CDT)      | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
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| 02:25:43.299    | WAPA              | Huron terminal of Huron-Storla 115kV line recloses. PCB 1362 reclosed. Systems are asynchronous across this line, resulting in the subsequent immediate trip at 02:25:43.625.                                                                                                                                                                                                                                                                                                     |
| 02:25:43.47     | UPA               | Ramsey 230 33RB3 Cap Bank 1 Automatically tripped                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:25:43.47     | UPA               | Ramsey 230 33RB4 Cap Bank 2 Automatically tripped                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:25:43.580    | OTP/MP            | Audubon CB 2125 tripped on instantaneous over current due to large current flow on Hubbard 230kV line. Closed at 03:23 by dispatcher.                                                                                                                                                                                                                                                                                                                                             |
| 02:25:43.625    | WAPA              | Huron terminal of Huron-Storla 115kV line opens, open ending the line. PCB 1362 tripped (phase distance, zone 1)                                                                                                                                                                                                                                                                                                                                                                  |
| 02:25:43.689    | WAPA              | Storla terminal of Huron-Storla 115kV line opens, momentarily de-energizing the Woonsocket substation and associated customer load, automatic reclose. PCB's 2266 and 2162 tripped (phase distance, zone 1)                                                                                                                                                                                                                                                                       |
| 02:25:43.750    | WAPA              | Granite Falls terminal of Granite Falls-Panther 230kV line opens, open ending the line to NSP's substation. PCB 682 tripped (phase distance) (NSP shows 02:25)                                                                                                                                                                                                                                                                                                                    |
| 02:25:43.751    | MP                | Wing River 915L OPEN by Zone 1 distance relay (Opens Wing River-Inman 230kV line)                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:25:43.795    | WAPA              | Granite Falls terminal of 69kV interconnection with UPA opens, automatic reclose. PCB 4352 tripped (phase distance, zone 1, phase B)                                                                                                                                                                                                                                                                                                                                              |
| 02:25 (approx.) | OTP               | Big Stone Plant tripped off line during voltage excursions, could not follow. Output was 342 MW before trip. On line at 09:06, off at 09:18, on line at 09:49 and released for 400 MW at 11:30.                                                                                                                                                                                                                                                                                   |
| 02:25 (approx.) | OTP               | Fergus Falls CB 2265 trips and recloses successfully. Zone 1 distance due to depressed voltage and large current flow on 230 line                                                                                                                                                                                                                                                                                                                                                 |
| 02:25:44.231    | UPA               | Coal Creek 230 61RB8,61RB9 CC Filter Bank 3 Overvoltage trip                                                                                                                                                                                                                                                                                                                                                                                                                      |
| 02:25:44.266    | UPA               | Coal Creek 230 61RB10,61RB11 CC Filter Bank 2 Overvoltage trip                                                                                                                                                                                                                                                                                                                                                                                                                    |
| 02:25:44.437    | MP                | <b>Square Butte HVDC Pole 2 trips</b> on over-frequency at 62.2 Hz. Pre-trip loading of both poles is 250 MW. Square Butte breakers 18 & 19 OPEN by Square Butte Pole #2 frequency Protection. Pole #1 picked up Pole #2's share of the flow. At 02:25:44.453, Pole 1 starts ramp (500 to 1000 amps). At 02:25:44.614 (177mSec after Pole #2 tripped) Pole 1 finishes ramp (at 1000 amps). After that time, no additional energy was transferred into the North Dakota AC system. |
| 02:25:44.792    | WAPA              | Storla terminal of Huron-Storla 115kV line re-closes, restoring service to Woonsocket substation. PCB 2266 reclosed.                                                                                                                                                                                                                                                                                                                                                              |
| 02:25:46        | NSP               | Open MN Valley - Bird Island 69kV                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 02:25:46        | UPA               | Willmar 69 13WB1 Willmar-MN Valley 115kV Tripped by Protections                                                                                                                                                                                                                                                                                                                                                                                                                   |
| 02:25:46        | UPA               | Willmar 69 13NB2 Willmar-Granite Falls 69kV Tripped by Protections (NSP shows 02:25:47)                                                                                                                                                                                                                                                                                                                                                                                           |
| 02:25:46        | UPA               | Willmar 69 13NB3 Willmar-Hutchinson 69kV Tripped by Protections                                                                                                                                                                                                                                                                                                                                                                                                                   |
| 02:25:46        | UPA               | Willmar 69 13NB6 Willmar-Granite Falls 230kV Tripped by protections                                                                                                                                                                                                                                                                                                                                                                                                               |
| 02:25:46.211    | WAPA              | Granite Falls terminal of 69kV interconnection with UPA recloses. PCB 4352 closed.                                                                                                                                                                                                                                                                                                                                                                                                |
| 02:25:47        | NSP               | Minnesota Valley - Franklin 115kV Open                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| 02:25:47        | NSP               | Open Douglas Cty - Osakis 69kV                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| 02:25:47        | NSP               | Willmar - Kerkhoven/MN Val. Jct 115kV Open                                                                                                                                                                                                                                                                                                                                                                                                                                        |

| Time (CDT)               | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
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|                          |                   | <p>The initial MN/MH/ND/SASK ISLAND has essentially completed a separation into two smaller ISLANDS, resulting in a North Dakota ISLAND and a Minnesota/Manitoba/Saskatchewan ISLAND being formed. However, one 115kV tie line remains energized between the two smaller ISLANDS (the Grant County-Douglas County 115kV line, which trips approximately 5 minutes later at 02:30:59). During the time this line remains in-service, the North Dakota system is slipping against the Minnesota system, resulting in significant voltage oscillations.</p> <p>The frequency of the ND ISLAND immediately increases to approximately 62 Hz.</p> |
| 02:25.48                 | MP                | Blanchard Generator 3U OPEN by relay                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
| 02:25.49                 | MP                | Square Butte 89FHP2 and 89F11-13P2 OPEN (Pole 2 Filters)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 02:25.50                 | MP                | Blanchard Generators 1U & 2U OPEN by relay                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| 02:25.50                 | NSP               | Open Douglas Cty – Westport 69kV                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 02:25:55.243             | WAPA              | <p>Antelope Valley Unit #2 tripped by over frequency (64 Hz max recorded), prior loading was 430 MW, loading at time of trip was 370 MW. PCB U2 tripped.</p> <p>The frequency of the ND ISLAND decreases to approx. 61 Hz over the next 20 seconds due to AVS2 trip, and then increases to approximately 61.8 Hz over the next 10 seconds until it appears that the Coyote unit tripped.</p>                                                                                                                                                                                                                                                 |
| 02:25.56                 | MP                | Square Butte 89TP2 OPEN (Pole 2 Line Disconnect)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 02:25:58                 | NSP               | Close Stone Lake – Bayfront 69kV                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 02:25:59                 | NSP               | <p>Ironwood – Park Falls 115kV Closed</p> <p>This line closure reconnected Minnesota/Manitoba/Saskatchewan ISLAND to Eastern Interconnection approx. 12 seconds after it was formed when North Dakota separated from the Minnesota/Manitoba/North Dakota/Saskatchewan ISLAND. The North Dakota ISLAND is still slipping against the Eastern Interconnection at this point through the Douglas County-Grant County 115kV line which is still energized.</p> <p>The frequency of the NSP/MH/SASK systems immediately decreases to approximately 59.95 Hz to match the frequency measured in the NPPD and DPC systems at the time.</p>          |
| 02:26                    | MAPP (MCN)        | MAPP SCO REQUESTED VOLUNTARY ECONOMY SCHEDULE REDUCTIONS TO ASSIST IN UNLOADING NSP'S 345KV LINES TO REDUCE THE PHASE ANGLE TO RECLOSE PRI-BYN.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| 02:26                    | NSP               | Afton - Red Rock 115kV Closed (by SCADA)                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 02:26 to 03:11 (approx.) | OH                | In preparation for the system restoration, opened all 230, 115 and 24kV breakers that were still closed and off potential.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| 02:26 (approx.)          | OTP               | Hoot Lake 2 tripped off line due to fuel trip, probably voltage related. Output was 32 MW before trip. On line at 04:36                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| 02:26:01.462             | WAPA              | Tioga PCB 782 closed, restoring Tioga 230/115kV interconnection and the Tioga-Logan 230kV line.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| 02:26:16                 | MP                | Poorly damped 0.15 Hz oscillation in ND suddenly stops                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 02:26:17.162             | MDU               | COYOTE 345KV JCT. SUB.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |

| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                             |
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|              |                   | TT-94TTP FROM PLANT<br>OPERATED -- Trip command issued from plant                                                                                                                                                                                                                                                                                                                 |
| 02:26:17.200 | MDU               | COYOTE 345KV JCT. SUB.<br>345KV PCB #5712 RING BUS<br>OPEN -- Ring bus opened                                                                                                                                                                                                                                                                                                     |
| 02:26:17.207 | MDU               | COYOTE 345KV JCT. SUB.<br>345KV PCB #5715 RING BUS<br>OPEN -- Coyote plant tripped off-line. Output was 375 MW prior to disturbance, approx 0 MW just prior to trip. Unit was on and off-line several times until 13:54 when it remained on-line.<br><br><b>The frequency of the ND ISLAND begins to decrease over the next approx. 2 minutes to settle between 61.3-61.4 Hz.</b> |
| 02:26:19     | NSP               | Red Rock - Crystal Cave 115kV Closed                                                                                                                                                                                                                                                                                                                                              |
| 02:26:19     | NSP               | South Faribault - West Owatonna 161kV Closed                                                                                                                                                                                                                                                                                                                                      |
| 02:26:21     | NSP               | Pine Lake - Rock Elm 69kV Closed                                                                                                                                                                                                                                                                                                                                                  |
| 02:26:22     | NSP               | King - Eau Claire 345kV Closed                                                                                                                                                                                                                                                                                                                                                    |
| 02:26:22     | NSP               | Pine Lake - Wissota 115kV Closed                                                                                                                                                                                                                                                                                                                                                  |
| 02:26:25.344 | WAPA              | Groton 345/115kV transformer KU2A tripped by Overvoltage protection. PCB's 8492, 8392, and 762 tripped (Instantaneous and timed overvoltage, transformer de-energized and locked out).                                                                                                                                                                                            |
| 02:26:50     | MP                | Square Butte 89PSS2 CLOSED (Pole Shorting Switch)                                                                                                                                                                                                                                                                                                                                 |
| 02:26:51     | NSP               | Highbridge #6 149 MW tripped                                                                                                                                                                                                                                                                                                                                                      |
| 02:26:55     | MP                | Arrowhead 89PSS2 CLOSED (Pole Shorting Switch)                                                                                                                                                                                                                                                                                                                                    |
| 02:27        | MAPP              | MEC / NEAL #2 & #3 TRIPPED.                                                                                                                                                                                                                                                                                                                                                       |
| 02:27:03     | NWPS              | Aberdeen PCB 5701 to Redfield closed by operator.                                                                                                                                                                                                                                                                                                                                 |
| 02:27:04.066 | UPA               | Dickinson 345 62JSM8 Dkn Band Pass Filter 2 Manually tripped for voltage control                                                                                                                                                                                                                                                                                                  |
| 02:27:11.635 | UPA               | Dickinson 345 62JSM2 Dkn Band Pass Filter 1 Manually tripped for voltage control                                                                                                                                                                                                                                                                                                  |
| 02:27:22     | MP                | Verndale 2K Capacitor Bank CLOSED                                                                                                                                                                                                                                                                                                                                                 |
| 02:27:36     | DPC               | Twin Lakes-Winnco 69kV looped (34NB9 Closed)                                                                                                                                                                                                                                                                                                                                      |
| 02:27:57.10  | UPA               | Ramsey 230 33RB2 Ramsey-Prairie 230kV Tripped by protections                                                                                                                                                                                                                                                                                                                      |
| 02:28        | MAPP (MCN-EM)     | MEC / NEAL-3 FOR 450 MWS X 0230 (JOINT). CANCELLED X 0330. TOTAL DELIVERED = 324 MWS-MEC & 126 MWS -ALT. OASIS #95205-MEC. OASIS #95214-ALT. TC E-MAILED.                                                                                                                                                                                                                         |
| 02:28:00.052 | UPA               | Dickinson 345 62JSM1 Dkn High Pass Filter 1 Manually tripped for voltage control                                                                                                                                                                                                                                                                                                  |
| 02:28:20.119 | UPA               | Dickinson 345 62JSM9 Dkn High Pass Filter 2 Manually tripped for voltage control                                                                                                                                                                                                                                                                                                  |
| 02:29:34.98  | UPA               | Ramsey 230 33RB1 Ramsey-McHenry 230kV Tripped on Overvoltage                                                                                                                                                                                                                                                                                                                      |
| 02:29:35.03  | UPA               | Ramsey 115 33WB1 Ramsey 230/115kV Transformer Tripped on Overvoltage                                                                                                                                                                                                                                                                                                              |
| 02:30:16     | MP                | Wing River 915L ATTEMPTED TO CLOSE VIA SCADA "FAILED TO CLOSE"                                                                                                                                                                                                                                                                                                                    |
| 02:30:59     | NSP               | Douglas County - Grant County 115kV line trips (Douglas County CB 5N606 trips due to a fault)<br><br><b>This line trip finally completes the electrical separation of the North Dakota ISLAND from the Eastern Interconnection, and ends</b>                                                                                                                                      |

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|                 |                   | the severe voltage oscillations, which had been occurring for approximately the last 5 minutes due to the slipping between the two areas.<br><br>The Grant County end breaker (OCB 1345) opens at 02:31:18. Alexandria CB 250 opened, MRES load lost. Restored at 05:36. Brandon 115 Sub loads lost, restored to normal at 05:24. Some loads on at 04:50 |
| 02:30:59        | NSP               | Elbow Lake CB 1314 opened. Loads restored at 04:19 and 04:46. This is part of Grant County-Douglas County line.                                                                                                                                                                                                                                          |
| 02:31           | MAPP (MCN-EM)     | SMP / SHERCO-3 FOR 230 MWS X 0233 (SOLE). LOWERED TO 100 MWS X 0335. CANCELLED X 0405. TOTAL DELIVERED = 288 MWS. OASIS #95207. TC E-MAILED.                                                                                                                                                                                                             |
| 02:31:44.012    | WAPA              | Bismarck terminal of Bismarck-Glenham 230kV line closed, restoring service to Glenham substation - 9min,45sec outage. PCB 582 closed.                                                                                                                                                                                                                    |
| 02:31.50        | MP                | Verndale 1-2KM and 2K OPEN                                                                                                                                                                                                                                                                                                                               |
| 02:32           | MAPP (MCN)        | WAPA / ISLANDED FROM THE SYSTEM. F = 61.363 Hz. REQUESTING FREQ. INFO FROM OTHERS.                                                                                                                                                                                                                                                                       |
| 02:32           | MAPP (MCN-EM)     | OTP / BIGSTONE FOR 219 MWS X 0234 (SOLE). LOWERED TO 100 MWS X 0600. CANCELLED X 0800. OASIS #95236. TC E-MAILED. TOTAL DELIVERED = 1006 MWS.                                                                                                                                                                                                            |
| 02:32:51        | UPA               | Coal Creek 230 61RSM1 CC Band Pass Filter 1 Manually tripped for voltage control                                                                                                                                                                                                                                                                         |
| 02:33:17        | NSP               | Prairie Island - Byron 345kV Closed (DPC shows at 02:33:49)                                                                                                                                                                                                                                                                                              |
| 02:34 (approx.) | MAPP (Phone Call) | ***** NERC HOTLINE ***** INITIATED BY MAPP - INFORMED ALL REGIONS OF MAPP STATUS. SUSPENDED FERC 888/889 AS A REGION, ASKED FOR ASSISTANCE WITH GENERATION RESERVES                                                                                                                                                                                      |
| 02:34           | MAPP (MCN-EM)     | OTP / COYOTE FOR 140 MWS X 0234 (SOLE). LOWERED TO 50 MWS X 0515. INCREASED TO 125 MWS X 0652. INCREASED TO 125 MWS X 0652. INCREASED TO 175 MWS X 0655. CANCELLED X 0800. OASIS #95235. TC E-MAILED. TOTAL DELIVERED = 594 MWS.                                                                                                                         |
| 02:34           | MAPP (MCN-EM)     | UPA / COAL CREEK #2 FOR 630 MWS X 0236 (JOINT). LOWERED TO 280 MWS X 0330. CANCELLED X 0400. TOTAL DELIVERED = 417 MWS-GSE & 290 MWS-UPA. OASIS #95208-UPA. OASIS #95215-GSE. TC E-MAILED.                                                                                                                                                               |
| 02:34:09        | IPW               | Open Montgomery (MN) 69kV, 6.0MVAR Cap Overvoltage                                                                                                                                                                                                                                                                                                       |
| 02:34:16        | UPA               | Coal Creek 230 61RSM3 CC Band Pass Filter 2 Manually tripped for voltage control                                                                                                                                                                                                                                                                         |
| 02:34:51        | DPC               | Close Pine Lake - Barron 69kV (CB 16NB4 Closed) (NSP shows at 02:34:55)                                                                                                                                                                                                                                                                                  |
| 02:36           | MAPP (MCN-EM)     | NWPS / BIGSTONE FOR 95 MWS X 0240 (SOLE). CANCELLED X 0330. TOTAL DELIVERED = 80 MWS. OASIS #95209. TC E-MAILED.                                                                                                                                                                                                                                         |
| 02:36:06.949    | WAPA              | Open-Ended Tioga-Boundary Dam 230kV (B10T) line de-energized from the Tioga end. PCB 882 opened manually via SCADA.                                                                                                                                                                                                                                      |
| 02:36:17        | UPA               | McHenry 230 32RB3 McHenry-Ramsey 230kV Transfer trip from Ramsey                                                                                                                                                                                                                                                                                         |
| 02:36:17        | UPA               | McHenry 115 32WB1 McHenry-Ramsey 230kV Transfer trip from Ramsey                                                                                                                                                                                                                                                                                         |

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| 02:36:34        | MAPP (MCN)        | WAPA / SUSPENDING FERC 888/889 DUE TO DISTURBANCE                                                                                                                                                         |
| 02:36:40.045    | SPC               | Boundary Dam-Tioga 230kV (B10T) line energized from Boundary Dam end. Still open at the Tioga end until 03:09:03.904.                                                                                     |
| 02:37           | MAPP (MCN-EM)     | NWPS / COYOTE FOR 40 MWS X 0240 (SOLE). CANCELLED X 0330. TOTAL DELIVERED = 33 MWS. OASIS #95210. TC E-MAILED                                                                                             |
| 02:38 (approx.) | MAPP (Phone Call) | MAPP SECURITY CENTER OPERATOR CALLED AEP TO REQUEST A TIME CORRECTION TO STOP THE FREQ. DECLINE. START TC 'H' @ 0300 @ F = 60.02 Hz. TE = -4.65 SEC.                                                      |
| 02:38:34        | IPW               | Open Highway 106 69kV, 6.1MVAR Cap Overvoltage                                                                                                                                                            |
| 02:38:55.231    | WAPA              | Bismarck terminal of Bismarck-Glenham 230kV line manually opened for voltage control, de-energizing the Glenham substation and associated customer load. PCB 582 tripped (by SCADA).                      |
| 02:39           | MAPP (MCN-EM)     | MEC / NEAL-4 FOR 411 MWS X 0241 (JOINT). CANCELLED X 0330. TOTAL DELIVERED = 248 MWS-MEC & 88 MWS-NWPS & 0 MWS ALT. OASIS #95206-MEC. OASIS #95213-ALT(INVALID-NO ALT EM). OASIS #95226-NWPS. TC E-MAILED |
| 02:39:10        | IPW               | Open Lime Creek 69kV, 6.0MVR Cap Overvoltage                                                                                                                                                              |
| 02:39:13        | MP                | Badoura 5R CLOSED by control                                                                                                                                                                              |
| 02:43           | MAPP (MCN)        | UPA / COAL CREEK FREQUENCY = 60.4 Hz.                                                                                                                                                                     |
| 02:45           | Exports           | NDEX=247 MW, MHEX=1161 MW, TCEX=43 MW                                                                                                                                                                     |
| 02:47:13        | UPA               | Hutchinson 69 C3NB3 Hutchinson Generators Tripped and reclosed at 2:51:19                                                                                                                                 |
| 02:50:15        | IPW               | Trip CB 34NB9 Winnco to Thompson 69kV zone 1φ                                                                                                                                                             |
| 02:50:51        | IPW               | Close CB 34NB9 Winnco to Thompson 69kV                                                                                                                                                                    |
| 02:51:13        | IPW               | Trip CB 735 Fox Lake to CP Durnel 69kV                                                                                                                                                                    |
| 02:51:19        | IPW               | Trip CB 734 Fox Lake to Fairmont 69kV                                                                                                                                                                     |
| 02:51:25        | IPW               | Trip CB 736 Fox Lake to St James 69kV<br>the Fox Lake 69kV bus was opened manually by Fox Lake Plant operators according to 'black start' contingency plan                                                |
| 02:51.34        | MP                | Wing River 915L (Wing River-Fergus Falls 230kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"                                                                                                             |
| 02:52.06        | MP                | Wing River 915L (Wing River-Fergus Falls 230kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"                                                                                                             |
| 02:52.54        | MP                | Badoura 64L (Badoura 230/115kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"                                                                                                                             |
| 02:52:57.635    | WAPA              | Huron terminal of Ft Thompson-Huron #1 230kV line closed, closing the line, line stayed in approx 1/2 sec before tripping. PCB 582 closed manually via SCADA.                                             |
| 02:52:58.192    | WAPA              | Huron terminal of Ft Thompson-Huron #1 230kV line opens, open ended the line. PCB 582 tripped (target to be determined).                                                                                  |
| 02:52:58.199    | WAPA              | Ft Thompson terminal of Ft Thompson-Huron #1 230kV line opens, de-energizing already open line. PCB 582 tripped (target to be determined).                                                                |
| 02:53           | MAPP (MCN)        | MAPP / MAPP AS A REGION SUSPENDED FERC 888/889 DUE TO SEVERAL OUTAGES AND SUBSEQUENT GENERATION TRIPPING.                                                                                                 |
| 02:53           | MP                | Ontario Hydro Fort Frances 22EH, 22EL3, 22HL1, 22JL1, 22JL6 &                                                                                                                                             |

| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                             |
|--------------|-------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
|              |                   | 22L3L6 OPEN                                                                                                                                                                                                                                                                                                                                       |
| 02:54        | MAPP              | MAIN & PJM POSTED MAPP CONDITION TO ITS MEMBERS.                                                                                                                                                                                                                                                                                                  |
| 02:54:22     | NSP               | Closed - Cannon Falls - Zumbrota 69kV                                                                                                                                                                                                                                                                                                             |
| 02:55        | MAPP (MCN)        | NSP / PRI-BYN BACK, ASK-ECL BACK. ECL-ARP STILL OUT.                                                                                                                                                                                                                                                                                              |
| 02:55:02.308 | WAPA              | Glenham terminal of Glenham-Sully Buttes 230kV line closed, restoring service to Glenham substation – 16min,7sec outage. PCB 282 closed manually via SCADA.                                                                                                                                                                                       |
| 02:55:10     | NSP               | Closed - Cannon Falls - Northfield 69kV                                                                                                                                                                                                                                                                                                           |
| 02:56:34     | NSP               | Closed - Cannon Falls - Spring Creek 69kV                                                                                                                                                                                                                                                                                                         |
| 02:57        | MAPP (MCN)        | WAPA / THINKS THEIR NORTH-SOUTH SYSTEMS ARE SEPARATED. APPEARS TO BE INTERCONNECTED AGAIN @ 0308 W/ STABLE FREQ.                                                                                                                                                                                                                                  |
| 02:58.44     | MP                | Badoura 64L (Badoura 230/115kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"                                                                                                                                                                                                                                                                     |
| 02:59:46     | NWPS              | Mitchell PCB 2731 to Huron 115kV closed by operator, energizing line. Huron end breaker still open.                                                                                                                                                                                                                                               |
| 02:59:51     | NSP               | (Eau Claire end only) Eau Claire – Arpin 345kV Closed                                                                                                                                                                                                                                                                                             |
| 03:00.02     | MP                | Blanchard Generator 1U CLOSED                                                                                                                                                                                                                                                                                                                     |
| 03:01.08     | MP                | Knife Falls Generator 1U CLOSED                                                                                                                                                                                                                                                                                                                   |
| 03:01:27     | DPC               | Trip CB 34NB40 Winnco to Grant 69kV (manually by DPC)<br><br>(IPW shows at 03:01:28) Opened Winnco 34NB40 by EMS to shed Grant, Linden, and Forest City. This was due to the overload of the Hayward-Twin Lakes-Winnco 69kV circuit and low voltage in the Winnco area. Voltage on the Winnco 161kV bus reached 191kV. 33 minute customer outage. |
| 03:02.48     | MP                | Knife Falls Generator 2U CLOSED                                                                                                                                                                                                                                                                                                                   |
| 03:03        | NSP               | Closed - King - Eau Claire - Arpin 345kV (Line restored)                                                                                                                                                                                                                                                                                          |
| 03:03        | NSP               | Closed - Panther – Granite Falls 230kV (Line restored later at 03:18:59.032 when WAPA closed Granite Falls end breaker.)                                                                                                                                                                                                                          |
| 03:03.12     | MP                | Winton Generator 2U CLOSED                                                                                                                                                                                                                                                                                                                        |
| 03:03.16     | MP                | Badoura 64L (Badoura 230/115kV) CLOSED by control.                                                                                                                                                                                                                                                                                                |
| 03:03:39.137 | WAPA              | <b>Bismarck terminal of Bismarck-Glenham 230kV line closed, restoring line to service. PCB 582 closed manually via SCADA.</b><br><br><b>Reconnected North Dakota ISLAND to Eastern Interconnection approx. 38 minutes after it was formed. North Dakota had been islanded from Eastern Interconnection for approx. 41-1/2 minutes.</b>            |
| 03:03.40     | MP                | Badoura 48L CLOSED by control                                                                                                                                                                                                                                                                                                                     |
| 03:03:43     | NSP               | Close MN Valley - Bird Island 69kV                                                                                                                                                                                                                                                                                                                |
| 03:03:44     | NSP               | Pathfinder - Split Rock 115kV Closed                                                                                                                                                                                                                                                                                                              |
| 03:03:44.182 | WAPA              | Huron terminal of Huron-Storla 115kV line closed, restoring line to service. PCB 1362 closed manually via SCADA.                                                                                                                                                                                                                                  |
| 03:03.50     | MP                | Blanchard Generator 2U CLOSED                                                                                                                                                                                                                                                                                                                     |
| 03:03:50     | WAPA              | <b>WAPA Frequency (measured at Watertown bus) is 60.03 Hz.</b>                                                                                                                                                                                                                                                                                    |
| 03:03.54     | MP                | Badoura 40L (Black Dog-Badoura 115kV) closed by control                                                                                                                                                                                                                                                                                           |
| 03:04.26     | MP                | Badoura 2K Capacitor Bank OPEN                                                                                                                                                                                                                                                                                                                    |
| 03:05:17.139 | WAPA              | Ft Thompson terminal of Ft Thompson-Leland Olds 345kV line closed, restoring line to service. PCB 2992 closed manually via SCADA.                                                                                                                                                                                                                 |
| 03:05:43     | UPA               | Willmar 69 13NB3 Willmar-Hutchinson 69kV Manually reclosed at 3:05:43                                                                                                                                                                                                                                                                             |



| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                                                                             |
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| 03:06        | MAPP (MCN)        | NSP / ECL-ARP BACK @ 0305                                                                                                                                                                                                                                         |
| 03:07:55.819 | WAPA              | Maurine terminal of Maurine-Hettinger 230kV line closed, restoring line to service. PCB 582 closed manually via SCADA.                                                                                                                                            |
| 03:08:58     | NSP               | Pine Lake - Apple River/Crystal Cave 161kV Closed                                                                                                                                                                                                                 |
| 03:09        | MAPP (MCN)        | IPW / XMS CURRENTLY OUT / LAKEFIELD-FOX LAKE 161KV, FOX LAKE-RUTLAND 161KV, WINNEBAGO JCT-WILMARTH 161KV, EMERY-FRANKLIN 161KV, HAYWARD-WINNEBAGO JCT 161KV, PLUS SEVERAL 69KV LINES.                                                                             |
| 03:09:03.904 | WAPA              | Tioga terminal of Tioga-Boundary Dam 230kV (B10T) line closed, restoring line to service. PCB 786 closed manually via SCADA. Tioga ring PCB 882 closed manually via SCADA at 03:09:34.212.<br><br><b>Tie line between Saskatchewan and North Dakota restored.</b> |
| 03:09:11.854 | WAPA              | Huron terminal of Huron-Ft Thompson #1 230kV line closed, restoring line to service. PCB 582 closed manually via SCADA.                                                                                                                                           |
| 03:09:36     | DPC               | Apple River-Crystal Cave 161kV restored                                                                                                                                                                                                                           |
| 03:11.30     | MP                | Blanchard Generator 3U CLOSED                                                                                                                                                                                                                                     |
| 03:12        | OH                | <b>OH Northwestern system restoration began from the OH eastern system.</b> Wawa-Marathon 230kV #1 (W21M) energized from Wawa.                                                                                                                                    |
| 03:13:08.208 | WAPA              | Split Rock terminal of Split Rock-White 345kV line closed, restoring line to service. PCB 196 closed manually via SCADA. (NSP shows at 03:13:11)                                                                                                                  |
| 03:15        | Exports           | NDEX=305 MW, MHEX=1194 MW, TCEX=184 MW                                                                                                                                                                                                                            |
| 03:15:52     | SPC               | Poplar River #2 unit resynched to the system.                                                                                                                                                                                                                     |
| 03:16:42     | NSP               | Wilmarth - Lakefield Jct. 345kV energized from NSP end.                                                                                                                                                                                                           |
| 03:18:59.032 | WAPA              | Granite Falls terminal of Granite Falls-Panther 230kV line closed, restoring the line to service. PCB 682 closed manually via SCADA.                                                                                                                              |
| 03:19:28     | NSP               | Close T-Corners - Wien 115kV                                                                                                                                                                                                                                      |
| 03:19:32     | IPW               | Close Wilmarth CB 885. Wilmarth-Lakefield 345kV line restored to service.<br><br><b>NSP transmission system essentially back to NORMAL.</b>                                                                                                                       |
| 03:20        | MAPP (MCN)        | NSP / WILMARTH-LAKEFIELD 345KV BACK                                                                                                                                                                                                                               |
| 03:20        | MAPP (MCN-EM)     | REQUESTED ALL COMPANIES TO RESPOND TO EM'S IN PROGRESS WITH THE ASSIGNED MWS.                                                                                                                                                                                     |
| 03:20:23.155 | WAPA              | Brookings terminal of Brookings-Flandreau 115kV line closed, restoring line to service. PCB 1862 closed manually via SCADA.                                                                                                                                       |
| 03:21        | OH                | All Kenora breakers reported open by traveler operators.                                                                                                                                                                                                          |
| 03:23        | MP                | OTP reports 2125 Breaker at Audobon CLOSED (909 line is service)                                                                                                                                                                                                  |
| 03:23:08     | IPW               | Close CB 881 Lakefield to Raun 345kV                                                                                                                                                                                                                              |
| 03:23.32     | MP                | Scanlon Generator 2U CLOSED                                                                                                                                                                                                                                       |
| 03:25        | MH                | Lettelier-Drayton 230kV (L20D) line restored to service                                                                                                                                                                                                           |
| 03:25:02     | IPW               | Close CB 884 Lakefield 345/161 Transformer                                                                                                                                                                                                                        |
| 03:26.08     | MP                | Square Butte 89TP2 (Pole 2 Line Disconnect) CLOSED                                                                                                                                                                                                                |
| 03:26.08     | MP                | Scanlon Generator 1U CLOSED                                                                                                                                                                                                                                       |
| 03:27        | MAPP (MCN)        | MH / L20D IN SERVICE @ 0325. WENT OUT @ 0225.                                                                                                                                                                                                                     |
| 03:28        | MAPP              | MP / WING RIVER-FERGUS FALLS 230KV. SQ BT HVDC POLE #2                                                                                                                                                                                                            |



| Time (CDT)   | Reporting Company | Event                                                                                                                                                                                                     |
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|              | (MCN)             | OUT. INTERNATIONAL FALLS-FORT FRANCIS OUT. NO GENERATION OUTAGES.                                                                                                                                         |
| 03:28:28     | MP                | Sandstone 4TM Transformer CLOSED auto                                                                                                                                                                     |
| 03:29        | MAPP (MCN)        | OPPD / ALL GEN OK                                                                                                                                                                                         |
| 03:29:14     | UPA               | Pine City 69 4NB2 Pine City-Hinckley 69kV Reclosed at 3:29:20                                                                                                                                             |
| 03:29:18     | MP                | Sandstone 4TM Transformer OPENED by relay<br>Hinckley 1T/1H1 Transformer OPENED by relay, remained open for transformer inspection                                                                        |
| 03:31        | OH                | Restoration of OH's NW system started from Manitoba by having Kenora-Whiteshell 230kV #1 (K21W) energized from Manitoba.                                                                                  |
| 03:31:41     | IPW               | Close CB 007 Emery to Franklin 161kV                                                                                                                                                                      |
| 03:32:10     | DPC               | Apple River 69kV Bus back in service                                                                                                                                                                      |
| 03:33:47     | MP                | Wing River 915L (Wing River-Fergus Falls 230kV) CLOSED by control                                                                                                                                         |
| 03:34        | MAPP (MCN)        | CBPC / CBPC 161KV SYSTEM BACK IN SERVICE. PUT TWO TURBINES ON-LINE & RAISED WINDOM TO MAX OUTPUT.                                                                                                         |
| 03:34        | MH                | <b>Whiteshell-Kenora 230kV (K21W) restored to service</b><br><br><b>Manitoba reconnected with Ontario.</b>                                                                                                |
| 03:34        | OH                | Kenora L21L24 closed.<br>K24F and Fort Frances T1 on potential via K21W.                                                                                                                                  |
| 03:34:57     | IPW               | Close CB 773 Fox Lake to Lakefield 161kV                                                                                                                                                                  |
| 03:35:31.091 | WAPA              | Spencer 161/69kV interconnection closed. PCB 1242 closed manually via SCADA.                                                                                                                              |
| 03:35:55     | UPA               | Crowell 115 18WB4 MP Cromwell-Riverton 115kV Reclosed by MP at 3:44:42                                                                                                                                    |
| 03:35:56     | MP                | Riverton 13L OPEN by relay, closed auto<br>Cromwell 13L OPEN by relay, closed auto                                                                                                                        |
| 03:36        | MAPP (MCN)        | IESC / SYSTEM CONDITION 'GREEN'                                                                                                                                                                           |
| 03:36:03     | MP                | Scanlon Generator 3U CLOSED                                                                                                                                                                               |
| 03:38:17     | IPW               | Close CB 737 Fox Lake 161/69kV Transformer                                                                                                                                                                |
| 03:38:40     | NSP               | Close Douglas County - Westport 69kV                                                                                                                                                                      |
| 03:38:50     | MP                | Square Butte breaker 18 & 19 (Pole 2 AC breakers) CLOSED                                                                                                                                                  |
| 03:38:56     | NSP               | Close Douglas County - Osakis 69kV                                                                                                                                                                        |
| 03:39        | MAPP (MCN)        | NWPS / HURON-MITCHELL 115KV OPEN. ALL OTHER XMS IS NORMAL.                                                                                                                                                |
| 03:39:23     | IPW               | Close CB 734 Fox Lake to Fairmont 69kV                                                                                                                                                                    |
| 03:40:00     | NSP               | Douglas County CB 5N606 closed energizing the Douglas County-Grant 115kV line. Additional switching of the breaker occurred during the day for maintenance reasons. The line was fully restored at 22:02. |
| 03:40:53     | IPW               | Close CB 736 Fox Lake to St James 69kV                                                                                                                                                                    |
| 03:41        | MAPP              | SECURITY CENTER OPERATOR CALLED AEP TO END TC 'N' DUE TO MAPP SYSTEM FREQ > 60.02 Hz. @ 6400 END TC. SET F = 60 Hz.                                                                                       |
| 03:42        | MAPP (MCN)        | OPPD / 161KV XMS SYSTEM INTACT. RAUN-FT CALHOUN 345KV W/ MEC BRKR'S OPEN.                                                                                                                                 |
| 03:42        | MAPP (MCN)        | MDU / COYOTE EXPECTED BACK IN AN HOUR.                                                                                                                                                                    |
| 03:42:17     | IPW               | Close CB 775 Fox Lake to Winnebago 161kV                                                                                                                                                                  |
| 03:43:07     | IPW               | Close CB 735 Fox Lake to CP Dannel 69kV                                                                                                                                                                   |

| Time (CDT) | Reporting Company | Event                                                                                                                                                                                                                   |
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| 03:43:52   | DPC               | Close CB 34NB40 Winnco to Grant 69kV (IPW shows at 03:43:54)                                                                                                                                                            |
| 03:45      | Exports           | NDEX=400 MW, MHEX=1312 MW, TCEX=481 MW                                                                                                                                                                                  |
| 03:45:31   | UPA               | Coal Ck, Dickinson CU HVDC Pole 1 de-blocked                                                                                                                                                                            |
| 03:46      | MAPP (MCN)        | UPA / CU HVDC POLE #1 DE-BLOCKED @ 0345.                                                                                                                                                                                |
| 03:48      | MP                | Square Butte DC Pole #2 restarted (75 MW per pole)                                                                                                                                                                      |
| 03:48      | MAPP (MCN)        | SJLP / GEN & XMS SYSTEM INTACT.                                                                                                                                                                                         |
| 03:48      | MAPP (MCN-EM)     | MDU / COYOTE FOR 40 MWS X 0349 (JOINT). THEY WANTED A SOLE EM. SKI CANCELLED EM X 0356. TOTAL DELIVERED = 1 MW-MDU, 2 MWS-OTP, 1 MW-MPC, 1 MW-NWPS. OASIS #95211-MDU, #95227-NWPS, #95228-OTP, #95229-MPC. TC E-MAILED. |
| 03:48:48   | OTP               | Jamestown Turbine #2 on line.                                                                                                                                                                                           |
| 03:49:04   | IPW               | Close CB 660 Hayward to Winnebago 161kV. Lakefield-Haywood 161kV is then restored (Winnebago-Wilmarth 161kV still out)                                                                                                  |
| 03:50      | MAPP (MCN)        | MP / WING RIVER-FERGUS FALLS 230KV INSERVICE @ 0333. POLE #2 OF SQ BT HVDC IN SERVICE @ 0348.                                                                                                                           |
| 03:50:13   | IPW               | Close CB 712 Rutland to Fairmont 69kV                                                                                                                                                                                   |
| 03:51      | OH                | Ontario East and West system tied at Lakehead TS. Ontario Hydro in synchronism with Manitoba Hydro.                                                                                                                     |
| 03:53      | MAPP (MCN)        | MPC / RAMSEY-PRAIRIE TRIPPED @ 0227. SBBT HVDC POLE 2 TRIPPED @ 0225 BACK @ 0348. L20D TRIPPED @ 0222 BACK @ 0325. YOUNG #2 ARMED @ 0355                                                                                |
| 03:53:07   | IPW               | Close CB 710 Rutland 161/69kV Transformer                                                                                                                                                                               |
| 03:53:54   | UPA               | Coal Ck, Dickinson CU HVDC Pole 2 de-blocked                                                                                                                                                                            |
| 03:55      | MP                | Stinson 6T CLOSED by control restoring Stinson-Minong 115kV line ( 762 Line in service) (NSP shows at 03:55)                                                                                                            |
| 03:56      | MAPP (MCN)        | UPA / CU HVDC IN BIPOLE OPERATION. WILMAR-GRANITE FALLS 230KV LINE BACK @ 0402.                                                                                                                                         |
| 03:56      | MAPP (MCN-EM)     | MDU / COYOTE FOR 40 MWS X 0358 (SOLE). CANCELLED X 0438. TOTAL DELIVERED = 26 MWS. OASIS #95212. TC E-MAILED.                                                                                                           |
| 03:59      | MAPP (MCN)        | LES / NO XMS & GEN OUT.                                                                                                                                                                                                 |
| 03:59      | MP                | Fond Du Lac 15L OPEN by control<br>Hibbard 15L OPEN by control, NORMAL OPERATING CONDITION FOR STORMS                                                                                                                   |
| 04:00      | OH                | Station service restored to Thunder Bay Generating Station                                                                                                                                                              |
| 04:00:50   | UPA               | Willmar 69 13NB6 Willmar-Granite Falls 230kV Manually closed                                                                                                                                                            |
| 04:01      | MAPP (MCN-EM)     | REQUESTED ALL COMPANIES TO CONTRIBUTE TO THE EM'S IN PROGRESS WITH THE ASSIGNED MWS. ALSO, REQUESTED THAT ANYONE NOT CONTRIBUTING INFORM THE MAPP CC AS TO THE REASON.                                                  |
| 04:01:08   | UPA               | Willmar 69 13NB2 Willmar-Granite Falls 69kV Manually closed (NSP shows at 04:01:13)                                                                                                                                     |
| 04:02:11   | OTP               | Lake Preston Turbine on line.                                                                                                                                                                                           |
| 04:03      | MAPP (MCN)        | MP / @ 0355 6T @ STINSON AVE CLOSED AND RAMPING UP PHASE SHIFTER TO NORMAL INTO WI.                                                                                                                                     |
| 04:03:36   | UPA               | McHenry 230 32RB3 Energize McH 230/115 Xfmr from                                                                                                                                                                        |

| Time (CDT)   | Reporting Company              | Event                                                                                                                                                                                                                                                                                                                                        |
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|              |                                | Stanton-Coal Creek 230kV line                                                                                                                                                                                                                                                                                                                |
| 04:03:52     | UPA                            | McHenry 115 32WB1 115kV breaker for McH 230/115 xfmr<br>Manually closed                                                                                                                                                                                                                                                                      |
| 04:05        | MAPP (MCN)                     | UPA / 32WB1 & 32RB3 CLOSED @ MCHENRY STATION @ 0403.                                                                                                                                                                                                                                                                                         |
| 04:07        | MAPP (MCN)                     | MPC / OTP REPORTS FERGUS FALLS-GRANT CO. 115KC OUT.                                                                                                                                                                                                                                                                                          |
| 04:10        | MEC                            | Lakefield-Raun 345kV line restored to service.                                                                                                                                                                                                                                                                                               |
| 04:11        | MAPP (MCN)                     | MP / THE BADOURA END OF BADOURA-BEMIDJI 115KV OUT.                                                                                                                                                                                                                                                                                           |
| 04:11        | MAPP (MCN)<br><br><b>(LLR)</b> | NSP / CANCEL LLR ON ECL-ARP & PRI-BYN IMMEDIATELY. (WAS DONE)                                                                                                                                                                                                                                                                                |
| 04:11:03     | IPW                            | Albert Lea Westside-Walters 69kV restored                                                                                                                                                                                                                                                                                                    |
| 04:13:02.220 | WAPA                           | Groton 345/115kV transformer KU2A restored to service. PCB's 8492 and 762 closed manually via SCADA (PCB 8392 subsequently closed)                                                                                                                                                                                                           |
| 04:14        | MEC                            | Raun-Ft Calhoun 345kV line restored to service.                                                                                                                                                                                                                                                                                              |
| 04:14        | MP                             | MPC reports 5412 breaker at Laporte CLOSED ( 725 line)                                                                                                                                                                                                                                                                                       |
| 04:14:45     | MPC                            | Prairie - Ramsey 230kV line closed                                                                                                                                                                                                                                                                                                           |
| 04:15        | Exports                        | NDEX=567 MW, MHEX=1470 MW, TCEX=624 MW                                                                                                                                                                                                                                                                                                       |
| 04:17:17     | UPA                            | Ramsey 230 33RB2 Ramsey-Prairie 230kV Manually closed                                                                                                                                                                                                                                                                                        |
| 04:17:25     | UPA                            | Ramsey 115 33WB1 Ramsey 230/115kV Xfmr Manually closed                                                                                                                                                                                                                                                                                       |
| 04:20        | MAPP (MCN)                     | MPC / MCHENRY-RAMSEY-PRAIRIE 230KV BACK @ 0418.                                                                                                                                                                                                                                                                                              |
| 04:22:11     | OTP                            | Jamestown Turbine #1 on line                                                                                                                                                                                                                                                                                                                 |
| 04:22:20     | UPA                            | Willmar 69 13WB1 Willmar-MN Valley 115kV Manually closed                                                                                                                                                                                                                                                                                     |
| 04:22:26     | NSP                            | Willmar - Kerkhoven/MN Val. Jct 115kV Closed                                                                                                                                                                                                                                                                                                 |
| 04:31        | MAPP (MCN)                     | IPW / SYSTEM BACK TO NORMAL<br><br><b>IPW system back to NORMAL.</b>                                                                                                                                                                                                                                                                         |
| 04:32        | MAPP (MCN)                     | NSP / @ 0500 NSP IS COMPLYING WITH FERC 888/889 REQUIREMENTS.                                                                                                                                                                                                                                                                                |
| 04:32:41     | NWPS                           | Huron-Mitchell 115kV line restored (Huron breaker closed)                                                                                                                                                                                                                                                                                    |
| 04:34        | MAPP (MCN)                     | NWPS / HURON-MITCHELL CLOSED @ 0433.                                                                                                                                                                                                                                                                                                         |
| 04:36        | MAPP (MCN)                     | WAPA / @ 0430 WAPA IS COMPLYING WITH FERC 888/889 REQUIREMENTS.                                                                                                                                                                                                                                                                              |
| 04:37        | NSP                            | High Bridge unit #6 back on-line                                                                                                                                                                                                                                                                                                             |
| 04:38        | MAPP (MCN)                     | MEC / SYSTEM CONDITION 'GREEN'                                                                                                                                                                                                                                                                                                               |
| 04:41        | MAPP (MCN)                     | MP / @ 0114 BADOURA 115KV BUS RELAYED - DUE TO B/O CCPD AND WAVE TRAP ON BADOURA.<br>BEMIDJI 115KV LINE BUS BACK IN @ 0303. BADOURA-BEMIDJI STILL OUT.<br>@ 0222 SQ BT HVDC POLE 2 STOPPED & CENTER 230KC AC BUSES OUT. ALL BACK @ 0348<br>@ 0225 WING RIVER-FERGUS 230KV OUT. BACK @ 0333<br>@ 0222 I'NAT FALLS-FT FRANCIS OUT. COMING BACK |

| Time (CDT) | Reporting Company | Event                                                                                                                                                                                                                |
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|            |                   | SHORTLY.                                                                                                                                                                                                             |
| 04:44      | MP                | Ontario Hydro CLOSED breaker 22EL3 and energized 726 line to the US.                                                                                                                                                 |
| 04:45      | Exports           | NDEX=493 MW, MHEX=1531 MW, TCEX=830 MW                                                                                                                                                                               |
| 04:45:09   | UPA               | Coal Creek 230 61RB2 Coal Creek Station Unit 2 Back on line<br><b>UPA system back to NORMAL.</b>                                                                                                                     |
| 04:47      | MAPP (MCN)        | UPA / COAL CREEK STATION #2 ON-LINE @ 0446.                                                                                                                                                                          |
| 04:48      | MAPP (MCN)        | MEC / NEAL #3 ON-LINE @ 0437. WILL GO TO 150 MWS, THEN RELEASE TO F/L. NEAL #4 CAN'T GET IGNITERS TO FIRE BOILER. NOT EXPECTED BACK BEFORE 0800.                                                                     |
| 04:56      | MAPP (MCN)        | ALT / @ 0500 WILL BE BACK IN COMPLIANCE WITH FERC 888/889 ORDERS.                                                                                                                                                    |
| 04:57      | MP                | <b>International Falls 726L CLOSED by control, MP-OH (F3M) interconnection restored. (OH shows at 04:57)</b><br><br><b>Minnesota Power-Ontario interconnection restored.</b><br><br><b>MP System back to NORMAL.</b> |
| 05:06      | MAPP (MCN)        | MAPP SYSTEM QUICK SYSTEM SUMMARY SENT.                                                                                                                                                                               |
| 05:08:46   | NSP               | Grant County OCB 1345 closed, beginning the restoration of the load at Elbow Lake, Alexandria, and Brandon.                                                                                                          |
| 05:10      | MAPP (MCN)        | DPC / ROCK ELM-ALMA 161KV OUT @ 0201. WILL FLY LINE IN MORNING.                                                                                                                                                      |
| 05:11      | MAPP (MCN)        | MP / @ 0457 I'NAT-FT FRANCIS LINE & PHASE SHIFTING XFMR BACK & @ ZERO FLOW.                                                                                                                                          |
| 05:15      | MAPP (MCN)        | IPW / FOX LAKE TRIPPED @ 0222. BACK @ 0438. ONLY HAVE BLUE LAKE-WINNEBAGO 161KV OUT.                                                                                                                                 |
| 05:15      | Exports           | NDEX=625 MW, MHEX=1671 MW, TCEX=1005 MW                                                                                                                                                                              |
| 05:17      | MP                | Ontario Hydro CLOSED 22EH,22HL1,22JL1,22JL6,22L3L6 at Fort Frances.                                                                                                                                                  |
| 05:20      | NPPD              | All customers lost during disturbance restored.<br><br><b>NPPD system back to NORMAL.</b>                                                                                                                            |
| 05:22      | MAPP (MCN)        | CBPC / EMERY-FRANKLIN-HAMPTON 161KV OPEN @ 0221. FRANKLIN END CLOSED @ 0258, HAMPTON END CLOSED @ 0259, EMERY END CLOSED @ 0331.                                                                                     |
| 05:33      | MAPP (MCN)        | WAPA / GROTON XFMR BACK @ 0413.                                                                                                                                                                                      |
| 05:43      | MAPP (MCN)        | IPW / LAKEFIELD-FOX LAKE 161KV BACK @ 0342, FOX LAKE-RUTLAND 161KV BACK @ 0406, WINNEBAGO JCT-WILMARTH 161KV STILL OUT, HAYWARD-WINNEBAGO JCT 161KV BACK @ 0406.                                                     |
| 05:45      | Exports           | NDEX=633 MW, MHEX=1723 MW, TCEX=1107 MW                                                                                                                                                                              |
| 05:46      | OH                | Northwestern Ontario 230kV system restored.                                                                                                                                                                          |
| 06:00      | OH                | Potential restored to all customer loads, 400 MW of load restored and 250 MW of heavy industrial load remained off.                                                                                                  |

| Time (CDT)      | Reporting Company | Event                                                                                                                                                                                                                                                                                                                                                                                                                                   |
|-----------------|-------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 06:15           | Exports           | NDEX=988 MW, MHEX=1687 MW, TCEX=1230 MW                                                                                                                                                                                                                                                                                                                                                                                                 |
| 06:28           | NSP               | Riverside unit #7 back on-line                                                                                                                                                                                                                                                                                                                                                                                                          |
| 06:45           | Exports           | NDEX=935 MW, MHEX=1690 MW, TCEX=1167 MW                                                                                                                                                                                                                                                                                                                                                                                                 |
| 06:48           | OTP               | Coyote was brought back on line and tripped off at 06:48 AM due to a fan problem. There were a few other start-ups and trips of the unit before it was finally returned at 13:54.                                                                                                                                                                                                                                                       |
| 06:56           | MEC               | Neal unit #2 back on-line, reached full load at 11:00                                                                                                                                                                                                                                                                                                                                                                                   |
| 07:15           | Exports           | NDEX=706 MW, MHEX=1810 MW, TCEX=1046 MW                                                                                                                                                                                                                                                                                                                                                                                                 |
| 07:42           | MAPP (MCN-EM)     | OTP / BIGSTONE-COYOTE COMBINED EM X 0800 FOR 305 MWS (SOLE).                                                                                                                                                                                                                                                                                                                                                                            |
| 08:41           | MEC               | Neal unit #4 back on-line, reached full load at 15:00.                                                                                                                                                                                                                                                                                                                                                                                  |
| 09:06           | OTP               | An attempt was made to get the Big Stone unit back on line and it Tripped back off at 09:18. Another attempt was made to bring it on line at 09:49, which was successful. Big Stone was released for 400 MW at 11:30.                                                                                                                                                                                                                   |
| 09:35           | OH                | Thunder Bay G3 unit back on-line                                                                                                                                                                                                                                                                                                                                                                                                        |
| 10:11           | WAPA              | Antelope Valley Station (AVS) unit #2 back on-line<br><br><b>WAPA/BEPCC system is back to NORMAL.</b>                                                                                                                                                                                                                                                                                                                                   |
| 10:15           | Exports           | NDEX=615 MW, MHEX=1692 MW, TCEX=639 MW                                                                                                                                                                                                                                                                                                                                                                                                  |
| 10:17:46        | MAPP (MCN)        | NSP / NSP SUSPENDED FERC 888/889 DUE TO LOSS OF GENERATION (MCN message from NSPM to BC)                                                                                                                                                                                                                                                                                                                                                |
| 11:30:57        | NSP               | Wilmarth-Winnebago 161kV line restored to service                                                                                                                                                                                                                                                                                                                                                                                       |
| 11:35           | NSP               | Sherco unit #3 back on-line                                                                                                                                                                                                                                                                                                                                                                                                             |
| 12:43           | NSP               | Closed - Minnesota Valley - Franklin 115kV                                                                                                                                                                                                                                                                                                                                                                                              |
| 13:54           | MPC               | Coyote unit back on-line (Breaker #5712 closed)                                                                                                                                                                                                                                                                                                                                                                                         |
| 15:00 (approx.) | MEC               | <b>MEC system is back to NORMAL.</b>                                                                                                                                                                                                                                                                                                                                                                                                    |
| 17:15           | Exports           | NDEX=1392 MW, MHEX=1694 MW, TCEX=1151 MW                                                                                                                                                                                                                                                                                                                                                                                                |
| 17:20:01        | MAPP (MCN)        | NSP / NSP WILL BE OUT OF SYSTEM EMERGENCY AT 18:00 AND WILL BE COMPLYING WITH FERC 888/889. (MCN Message from NSPM to BC)                                                                                                                                                                                                                                                                                                               |
| 18:00           | NSP               | <b>NSP system is back to NORMAL</b>                                                                                                                                                                                                                                                                                                                                                                                                     |
| 20:52           | NSP               | Closed - Lafayette - Schilling 69kV                                                                                                                                                                                                                                                                                                                                                                                                     |
| 22:02           | OTP               | Douglas County-Grant County 115kV line was returned to service. Both ends of the line were closed at the times stated in the sequence of events at 03:40 and 05:08:46, but what was not listed was additional switching along this line (Elbow Lake, Brandon, and Alexandria) and several opening and closing operations of the breaker at Douglas County. The entire Douglas County-Alexandria 115kV line was closed through at 22:02. |
| 21:00 (approx.) | MAPP (MCN)        | <b>MAPP AS A REGION COMPLYING WITH FERC 888/889.</b>                                                                                                                                                                                                                                                                                                                                                                                    |

Notes:

1. Broadcasts on the MAPP Communications Network are noted with "MAPP (MCN)". Broadcasts related to MAPP Emergency Energy Replacement Procedure (EM) are noted with "MAPP (MCN-EM)".
2. Exports are from 30 minute interval exports posted on MAPP Web Page. Times on these entries are approximate. Systems submit data at 15minutes after and 15 minutes before the hour. The data on the MAPP Web page is shown as 24 minutes after and 6 minutes before the hour due to processing delay at MAPP.
3. Times that are uncertain, are shown marked "(approx.)". They are ordered in the sequence of events where it appears they most likely occurred.

## Disturbance Report Figures

- Figure #1 Map of the area affected by the disturbance
- Figure #2 Map of the major line trips and islands in the MAPP region
- Figure #3 One-line diagram of the NW Ontario system
- Figure #4 NSP (King), DPC (LaCrosse), and NPPD (Columbus) Frequencies
- Figure #5 NSP (King), DPC (LaCrosse), and WAPA (Watertown) Frequencies
- Figure #6 Prairie Island-Byron 345kV line trip. Arrowhead frequency
- Figure #7 King-Eau Claire 345kV line trip. Arrowhead frequency
- Figure #8 Northwest Wisconsin Separation. Arrowhead frequency
- Figure #9 MN/Manitoba/Saskatchewan/ND islanding. Arrowhead frequency
- Figure #10 CU HVDC Pole 1 Manual Trip. Arrowhead frequency
- Figure #11 ND-MN/Manitoba/Saskatchewan Separation. Arrowhead frequency
- Figure #12 Voltage at King 345kV Substation (Prior to the disturbance)
- Figure #13 Bismarck 230kV West Bus Voltage
- Figure #14 King 345kV Bus Voltage
- Figure #15 King 345kV Voltage Oscillations (About 02:26 to 02:31 CDT)
- Figure #16 North Dakota Post-Separation Oscillation. Center frequency
- Figure #17 June 25, 1998 Twin Cities Export (TCEX) values
- Figure #18 MEC Neal North Generator Var Output
- Figure #19 Watertown Static Var System (SVS) Mvar
- Figure #20 Frequency in DPC (LaCrosse) Across 03:00 CDT
- Figure #21 Tioga-Boundary Dam 230kV Line Flows
- Figure #22 Voltage Oscillations at Boundary Dam Station
- Figure #23 Alma 161kV Bus Voltage Swings
- Figure #24 OTP Tie Line Flows

dist0625.doc  
09/10/98, SCS/CGP

Attachment B - Northern MAPP Northwestern Disturbance June 25 1998

The FINAL report for the 06/25/98 Northern MAPP/Northwestern Ontario Disturbance is provided in this directory in two PDF type files:

dist0625\_rpt.pdf - Report Text (227428 bytes)  
dist0625\_fig.pdf - Report Figures (614561 bytes)

This report was APPROVED by the MAPP Operating Review Subcommittee (ORS) on 9/2/98 at their meeting in Brainerd, MN.

If you have any questions regarding the report, please contact:

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or,

Carlos Gonzalez-Perez, MAPP  
612-330-0541, email: [c.gonzalez-perez@mapp.org](mailto:c.gonzalez-perez@mapp.org)



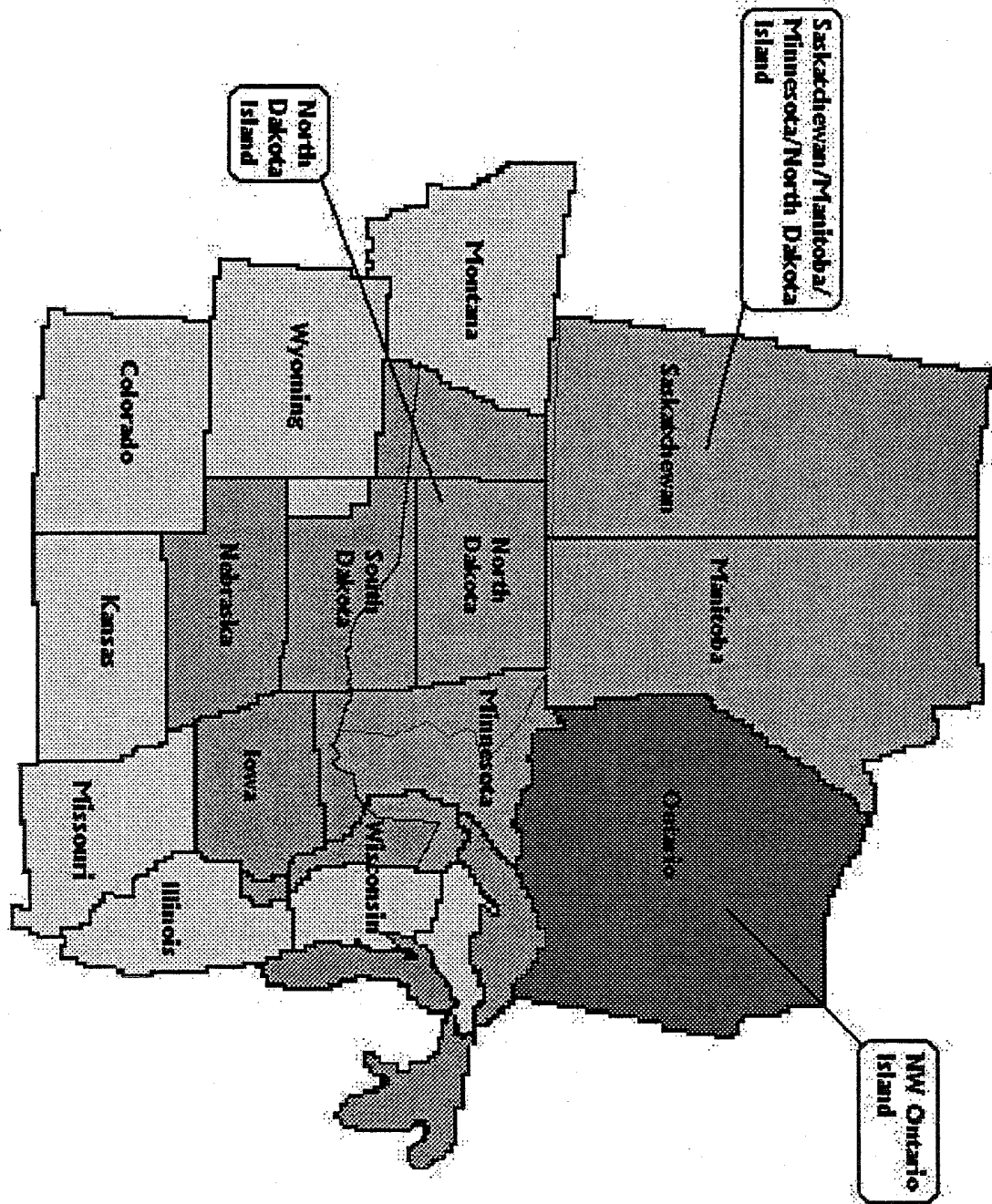
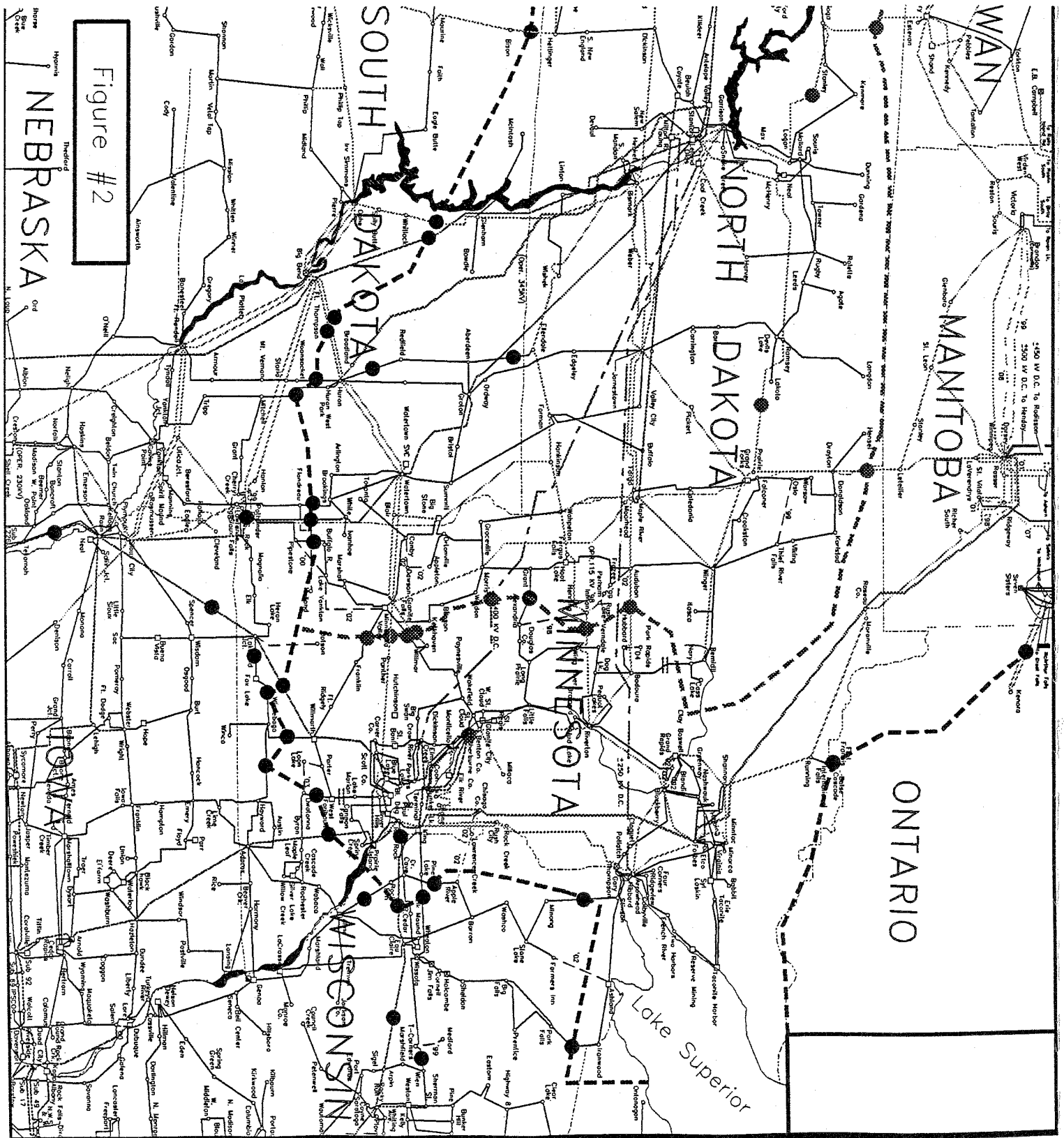


FIGURE #1



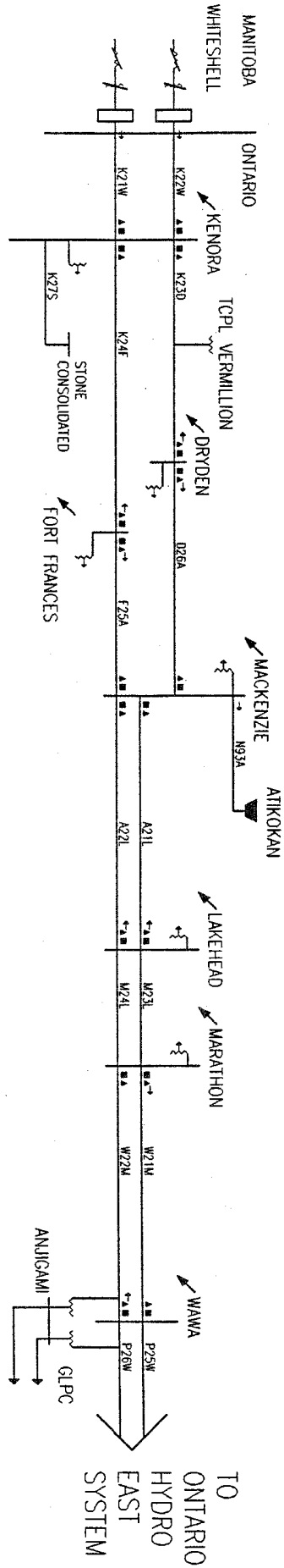


FIGURE #3

NW ONTARIO HYDRO SYSTEM

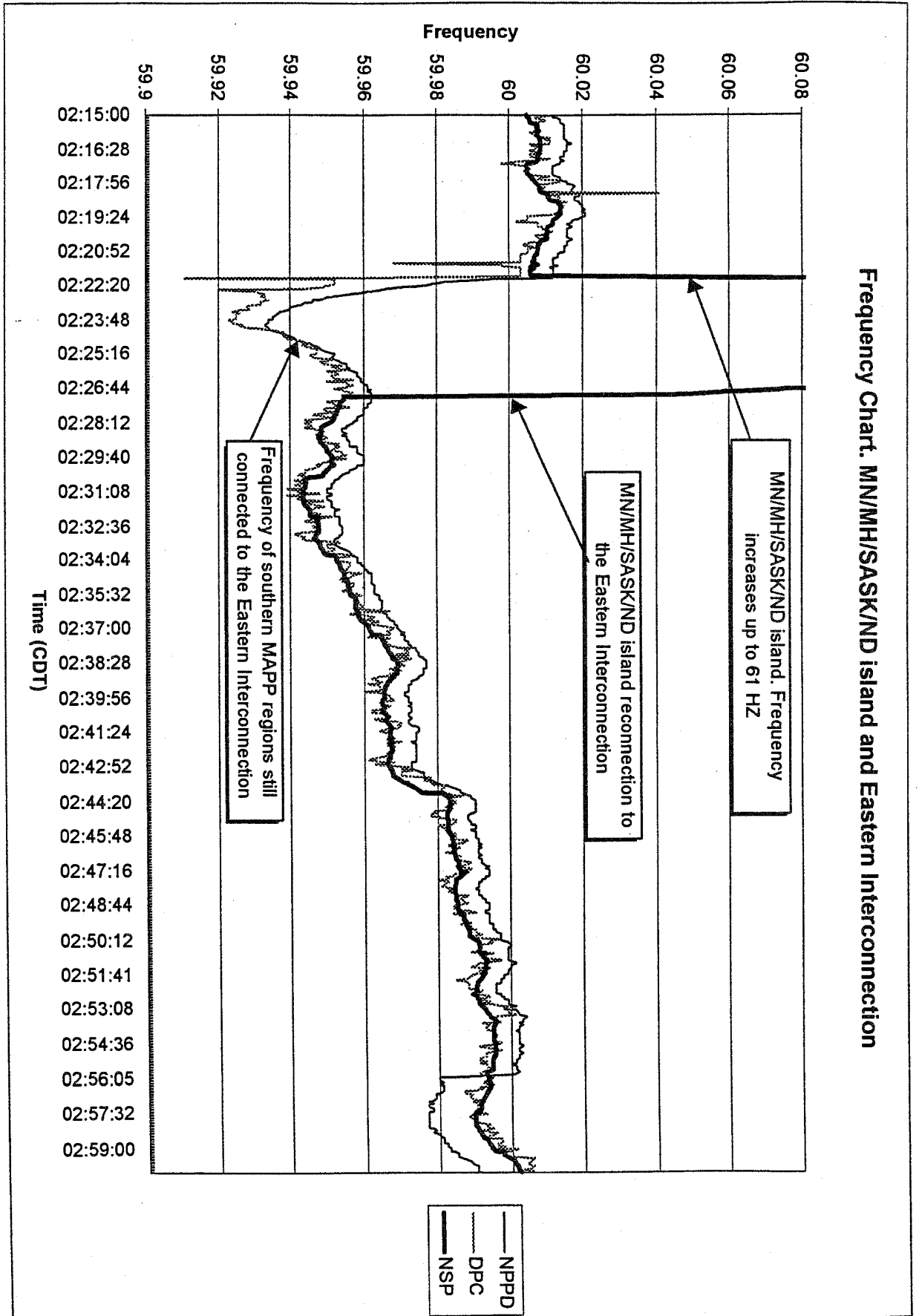
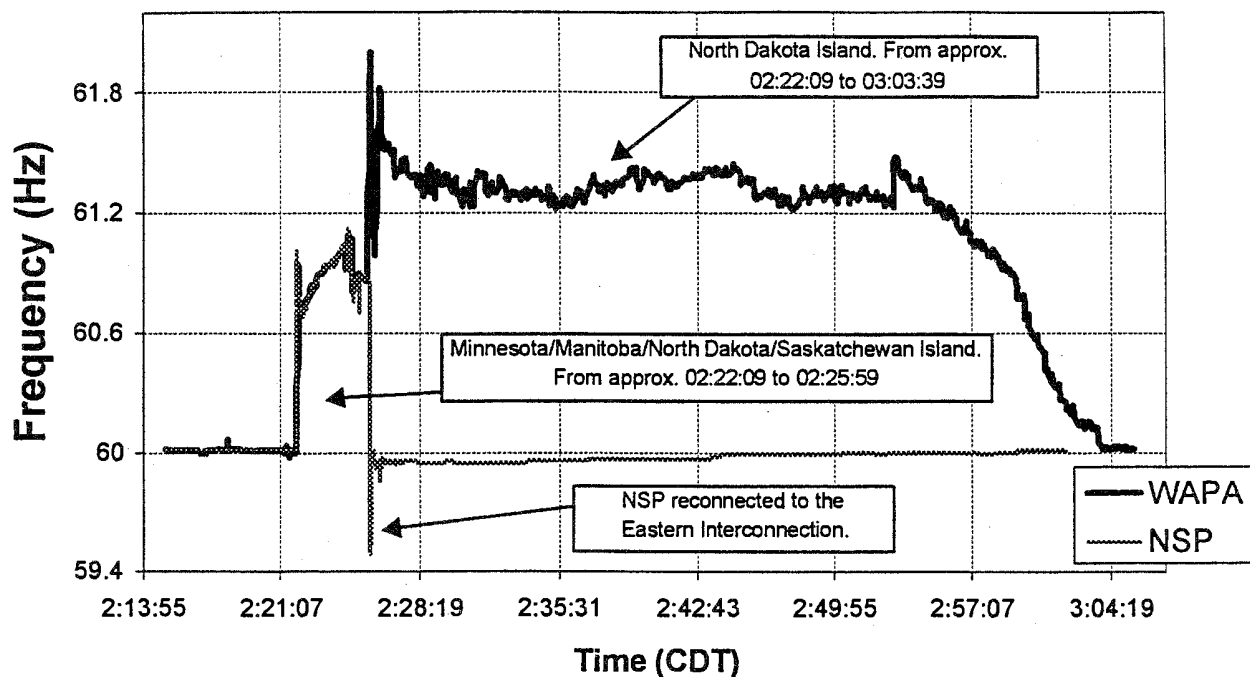


FIGURE #4

## NSP (King) and WAPA (Watertown) Frequencies on 6/25/98



## DPC (LaCrosse) Frequency on 6/25/98

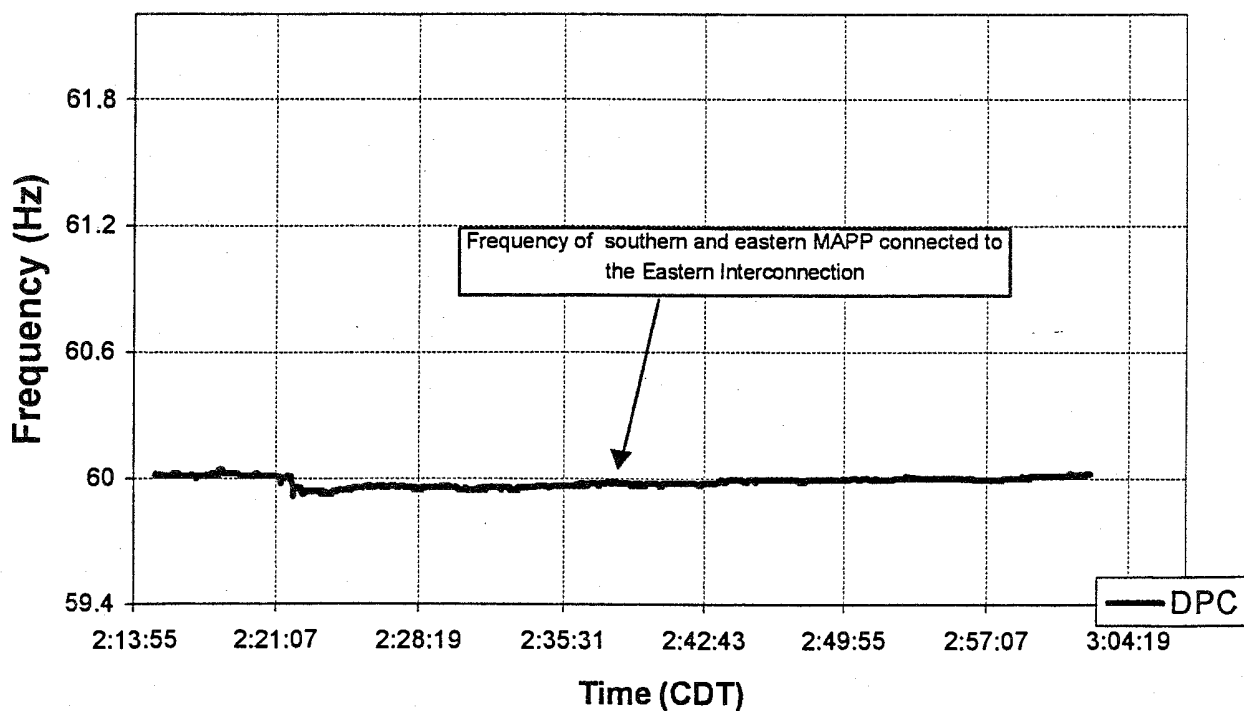


FIGURE #5

# Prairie Island-Byron 345kV Line Trip Arrowhead Frequency

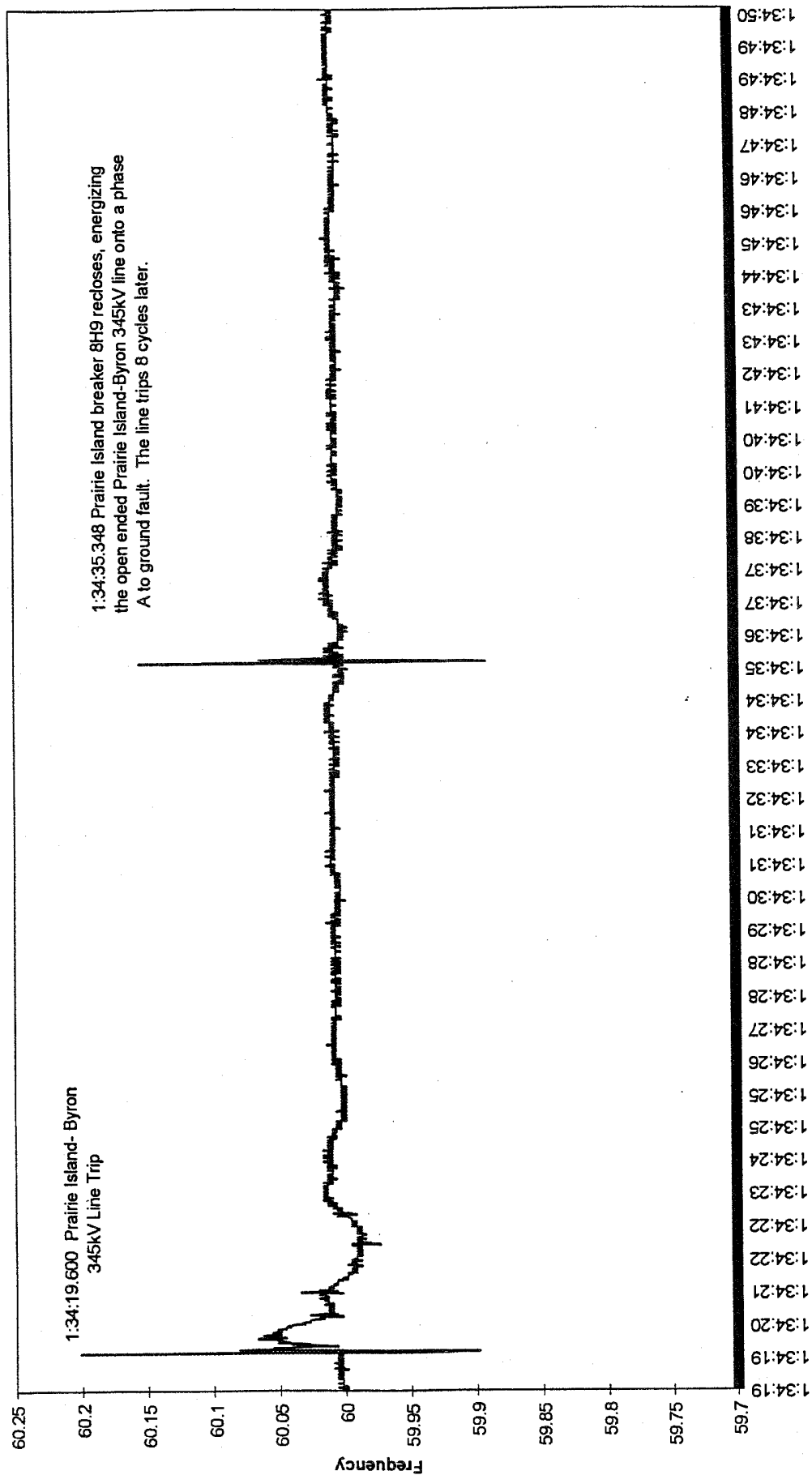


FIGURE #6

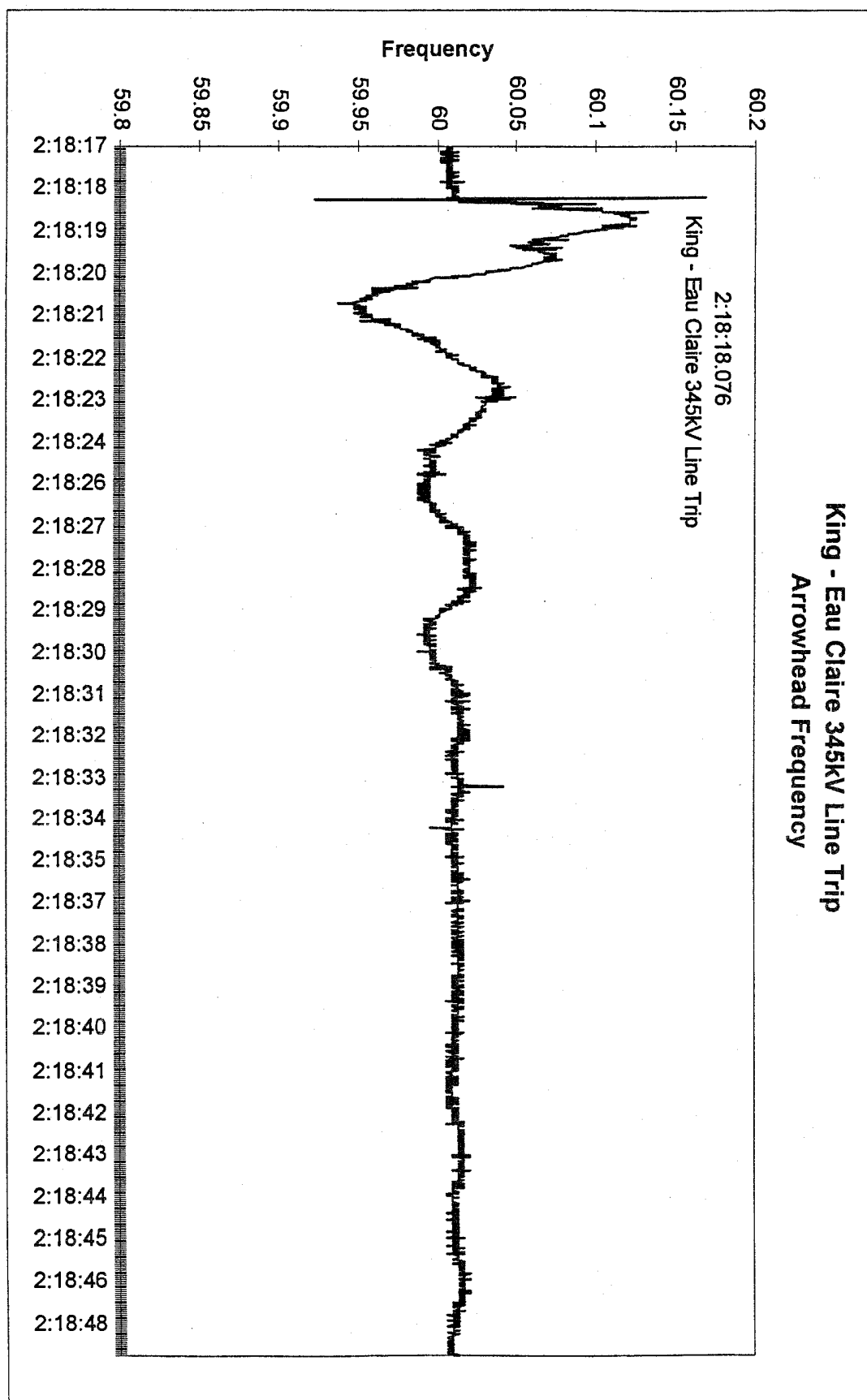


FIGURE #7

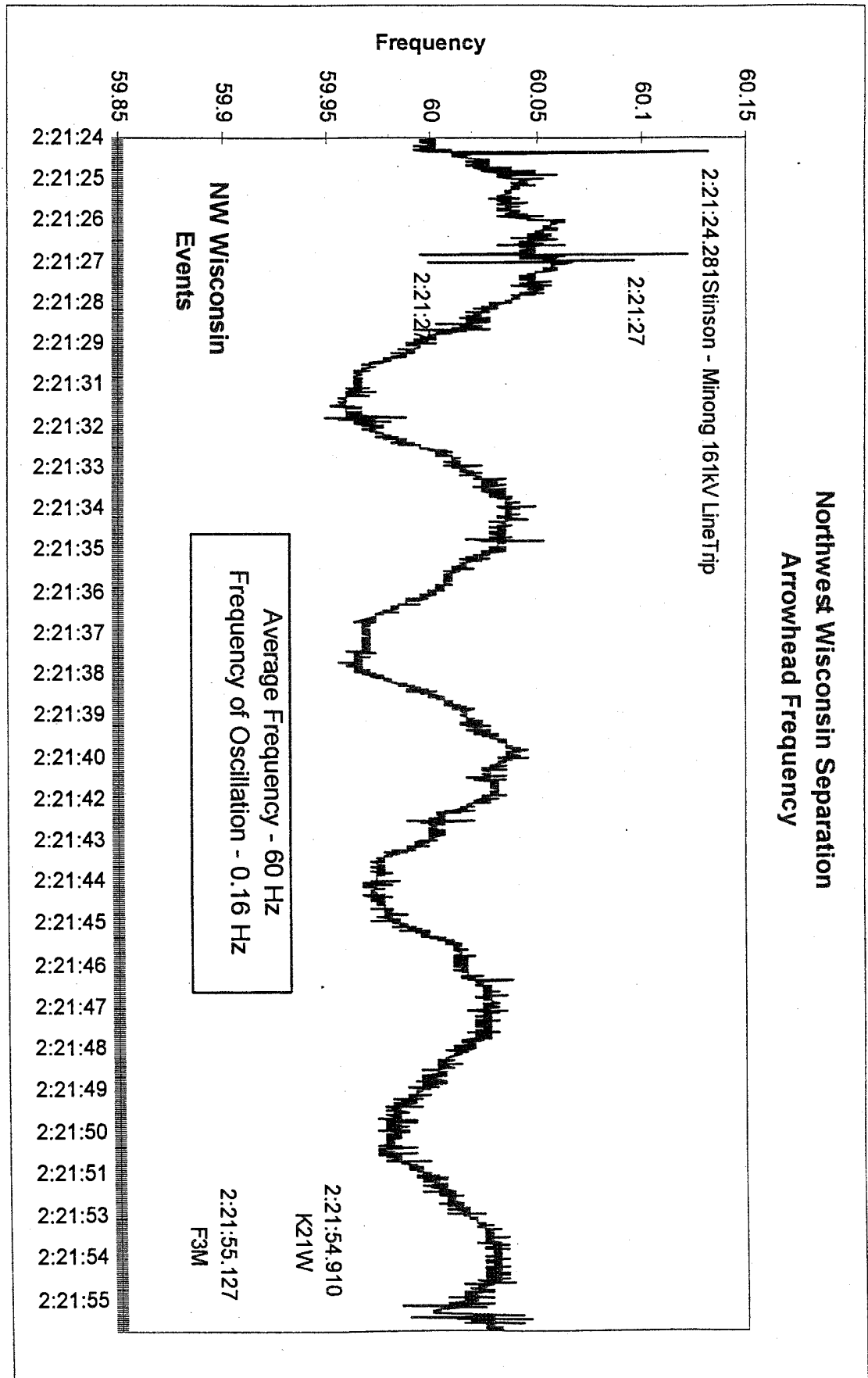


FIGURE #8



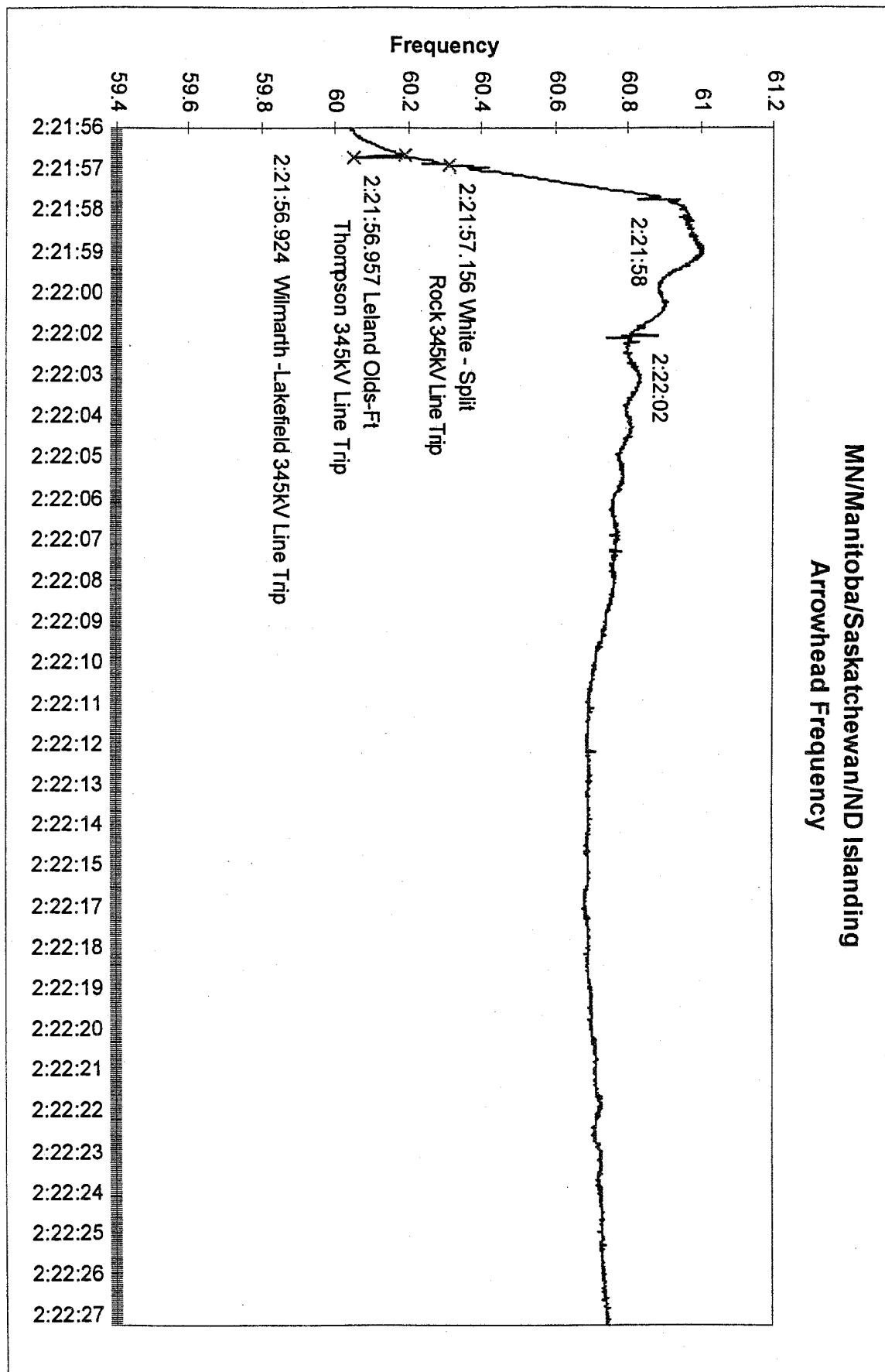
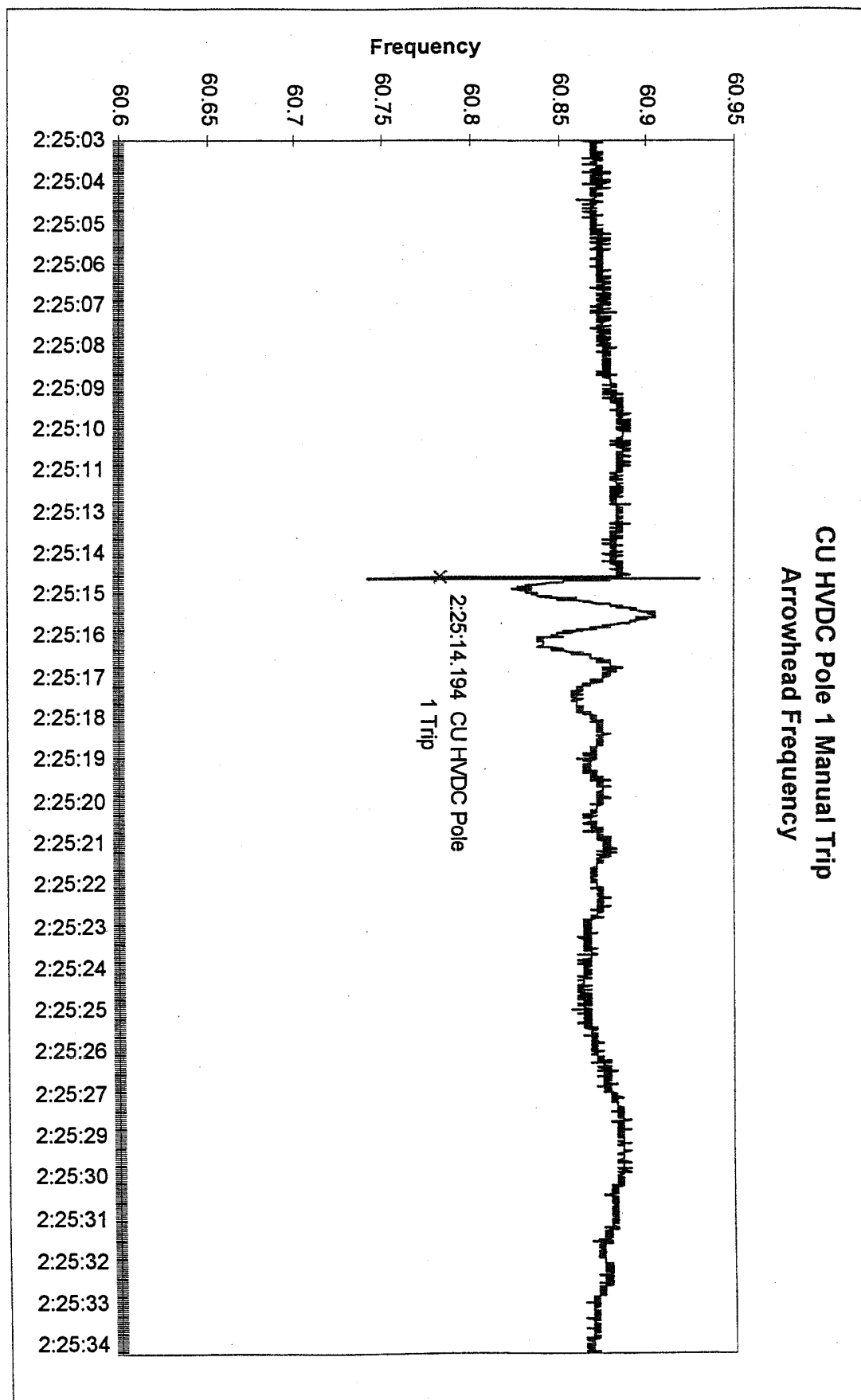


FIGURE #9

FIGURE #10



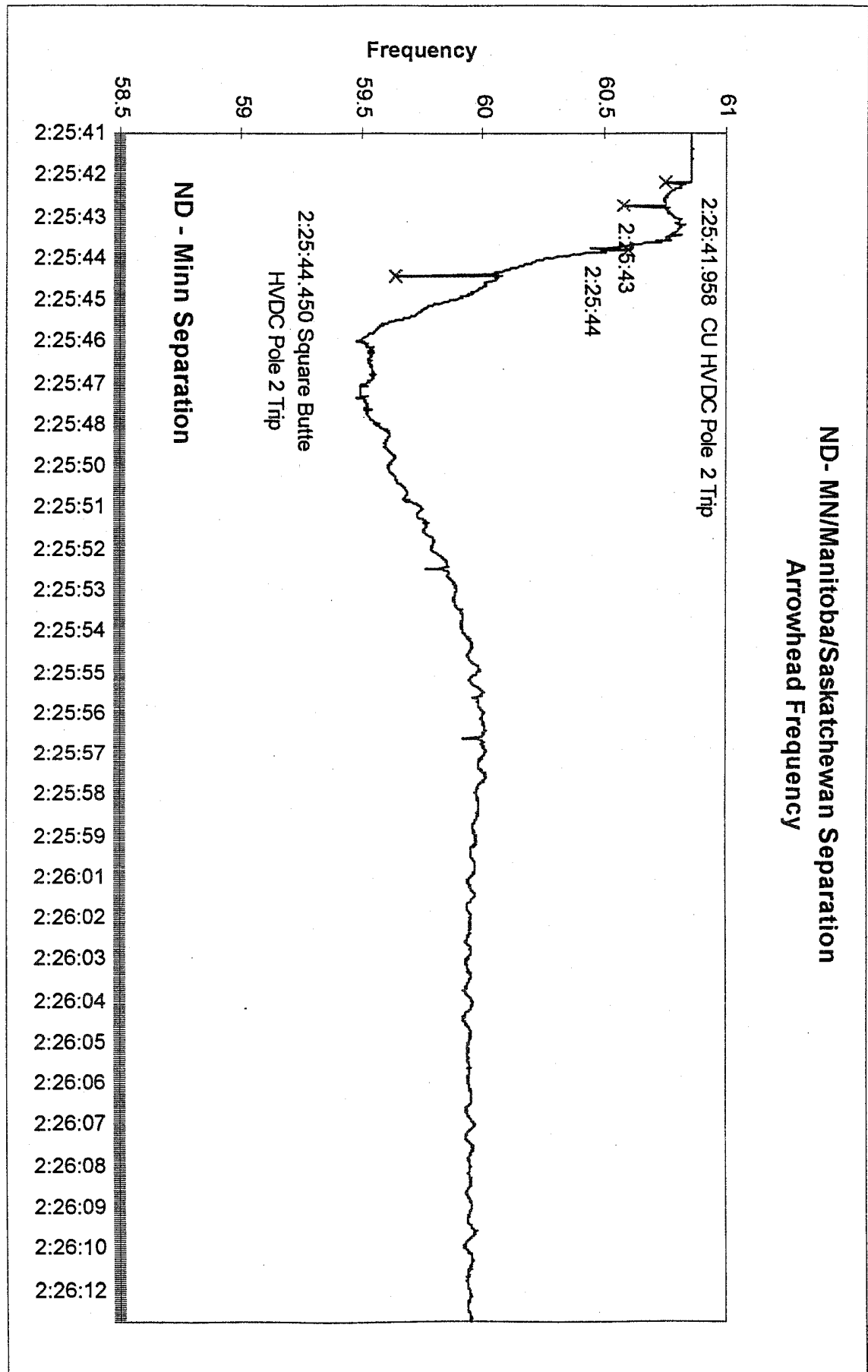


FIGURE #11

June 25, 1998 King 345 kV bus Voltage

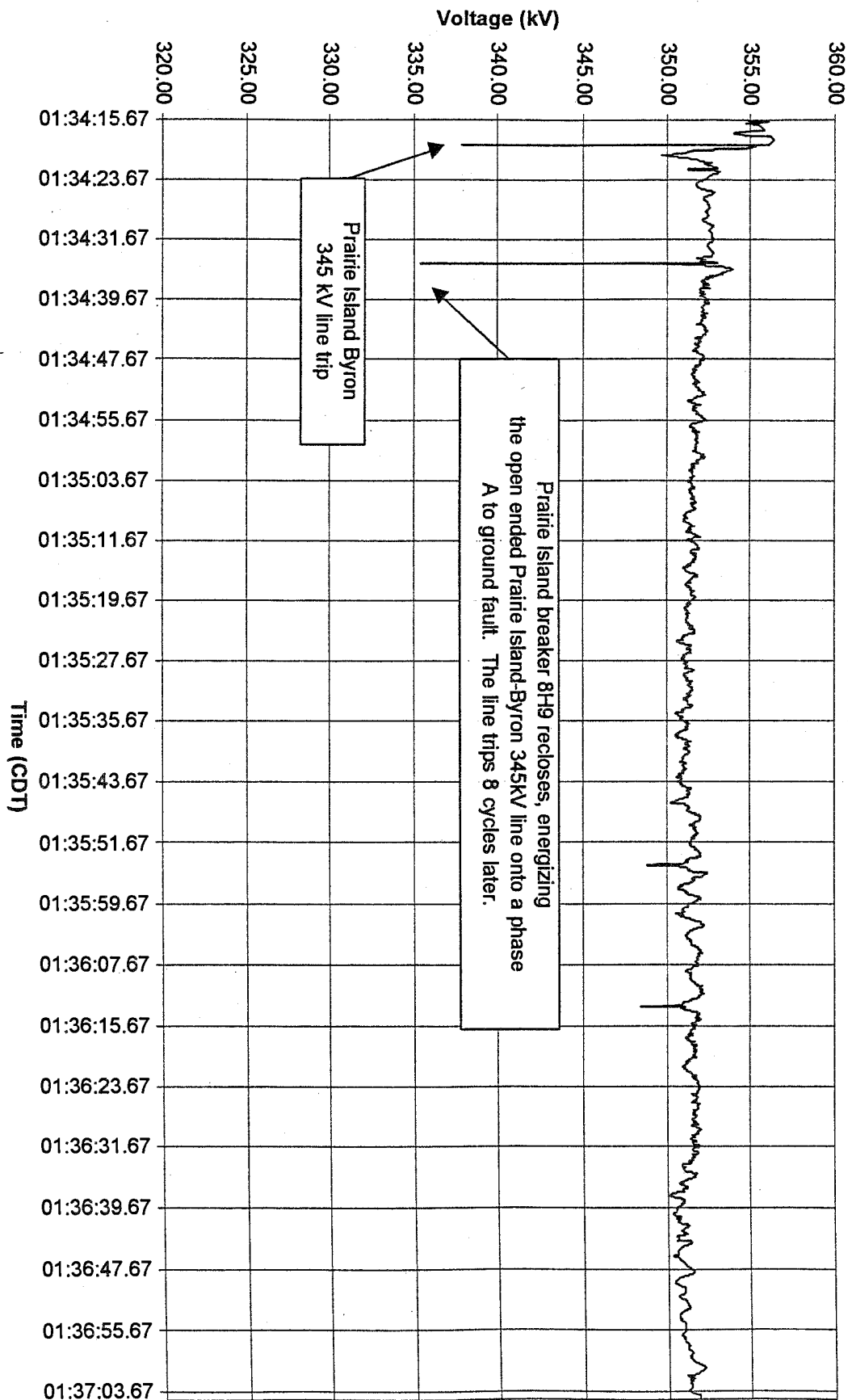


FIGURE #12

# BISMARCK 230 KV WEST BUS VOLTAGE

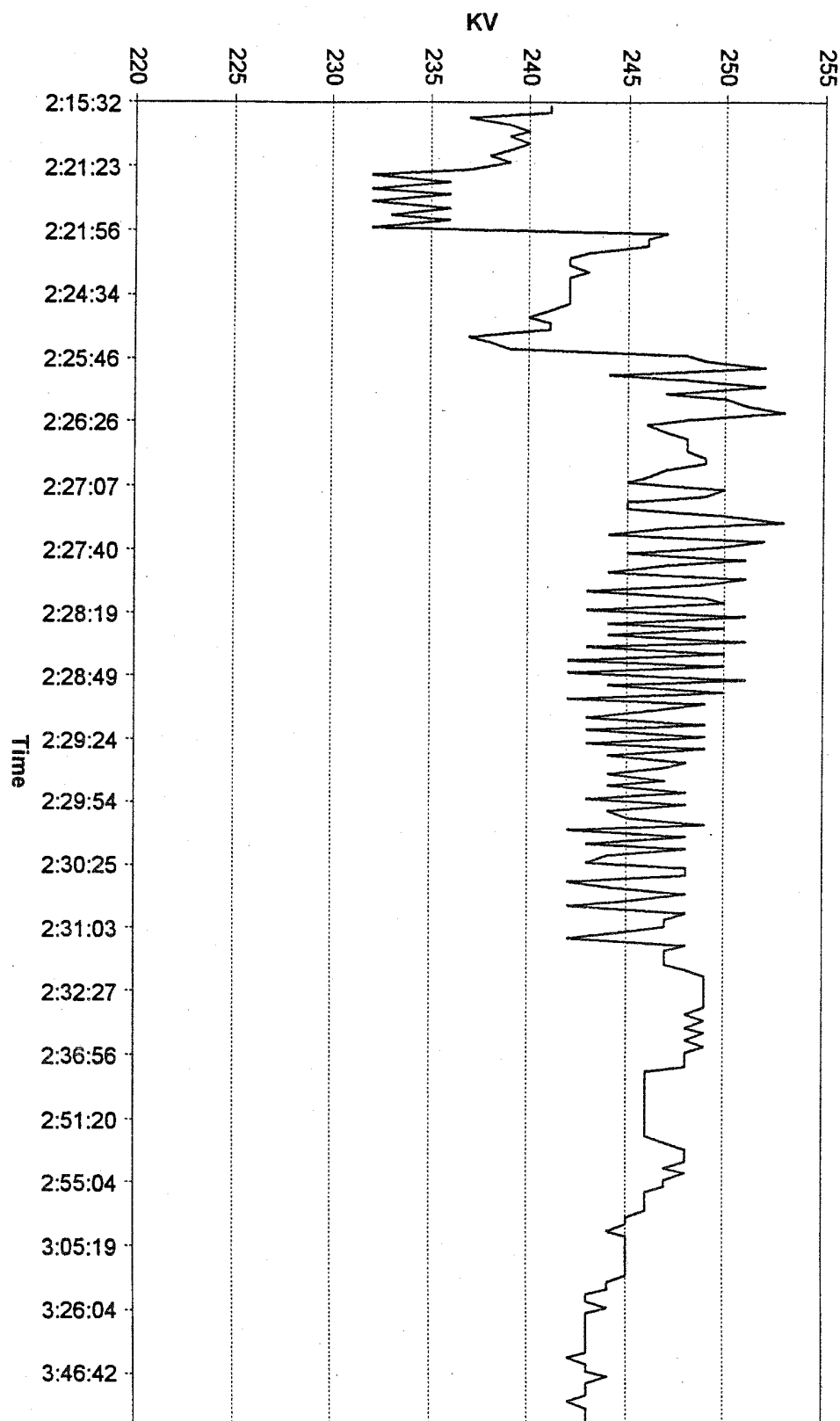


FIGURE #13

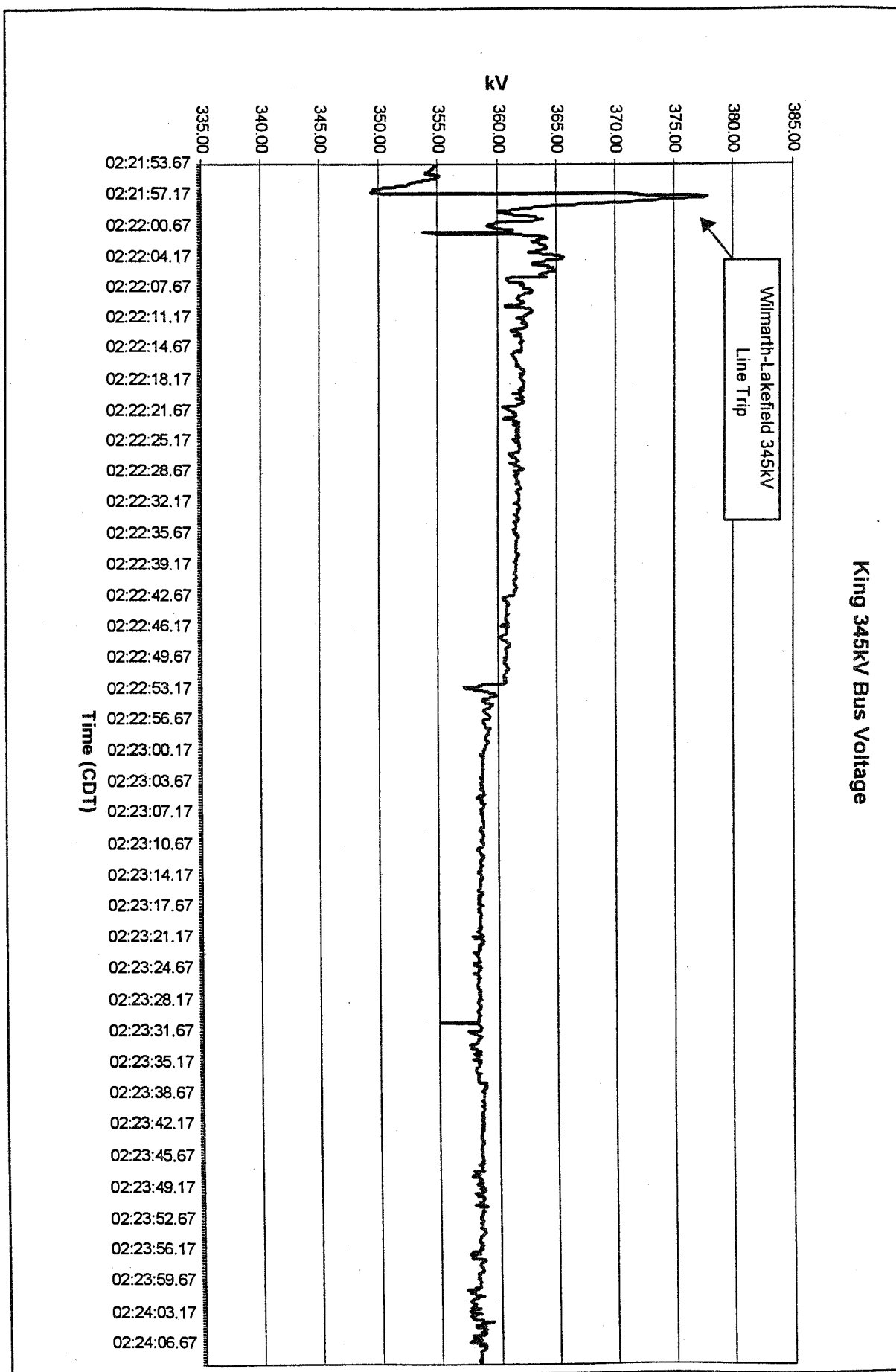


FIGURE #14

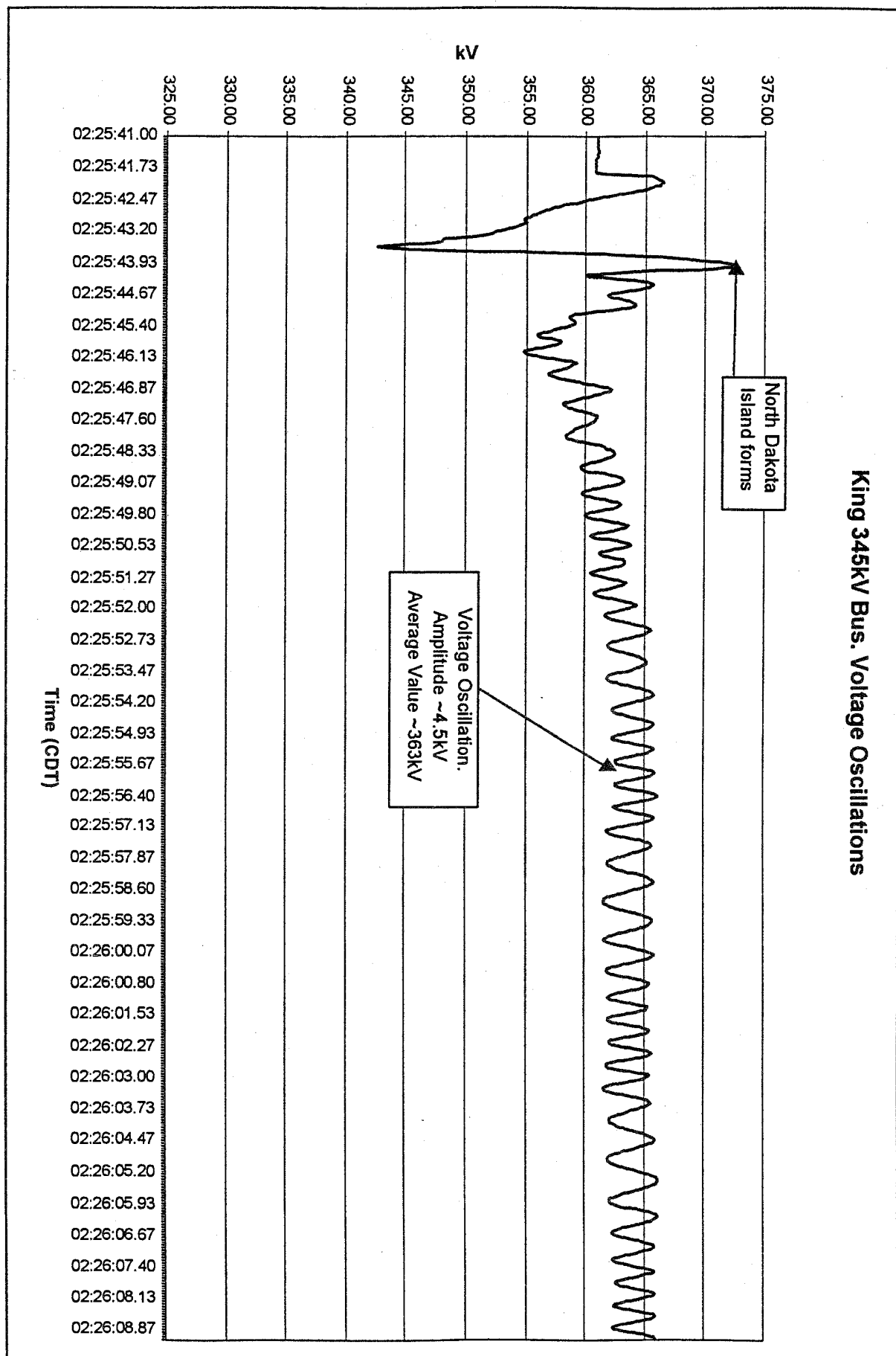
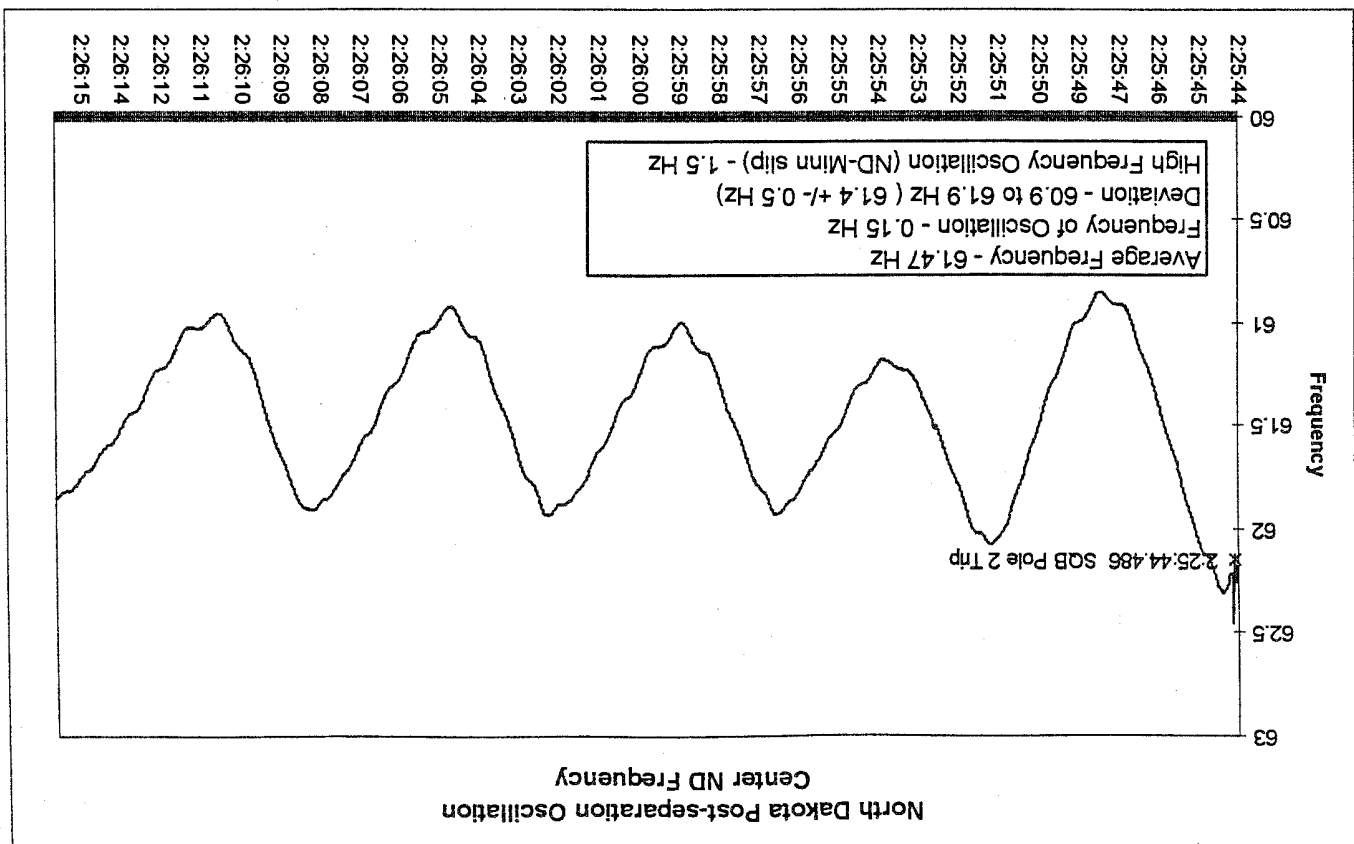
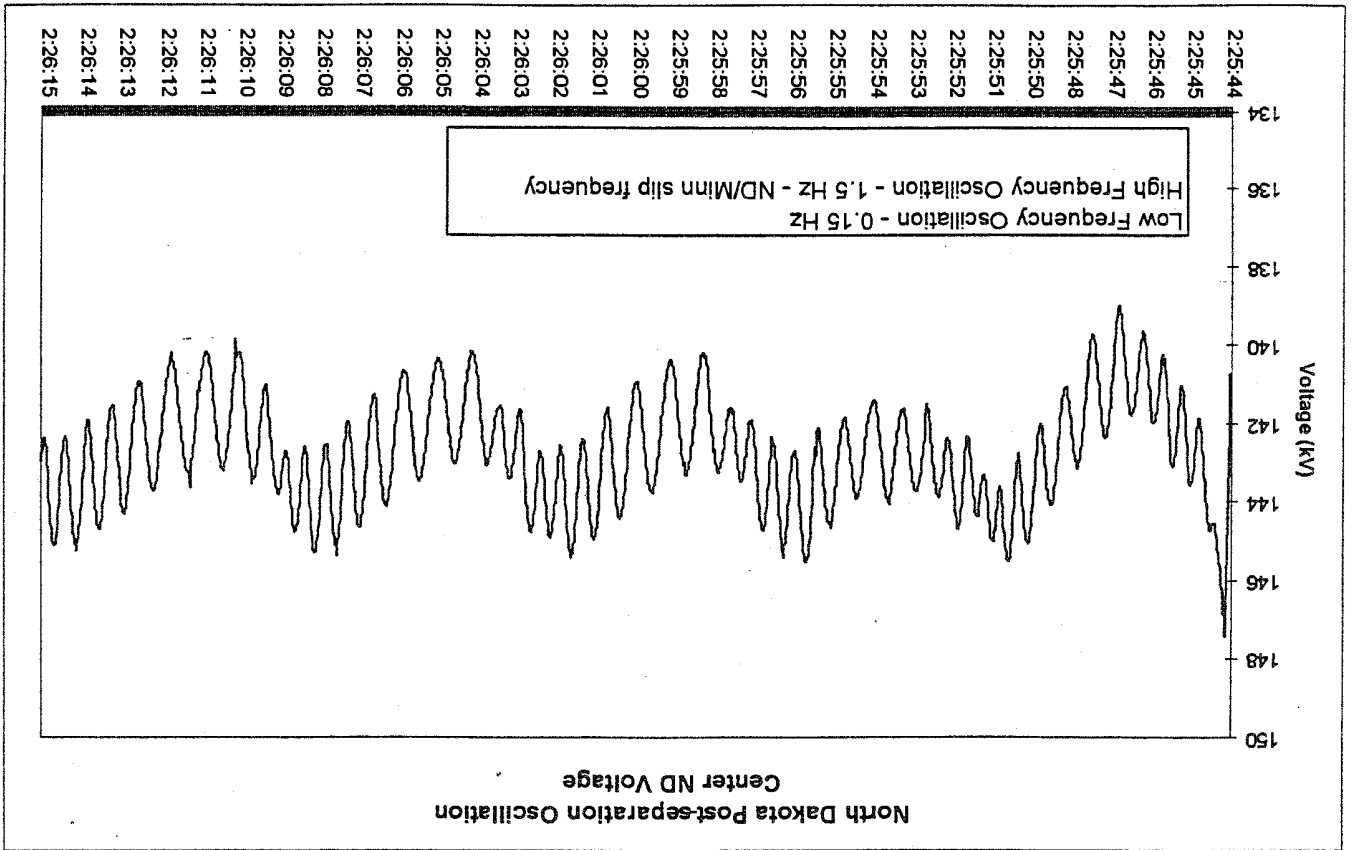


FIGURE #15

FIGURE #16





June 25, 1998 TCEX Values

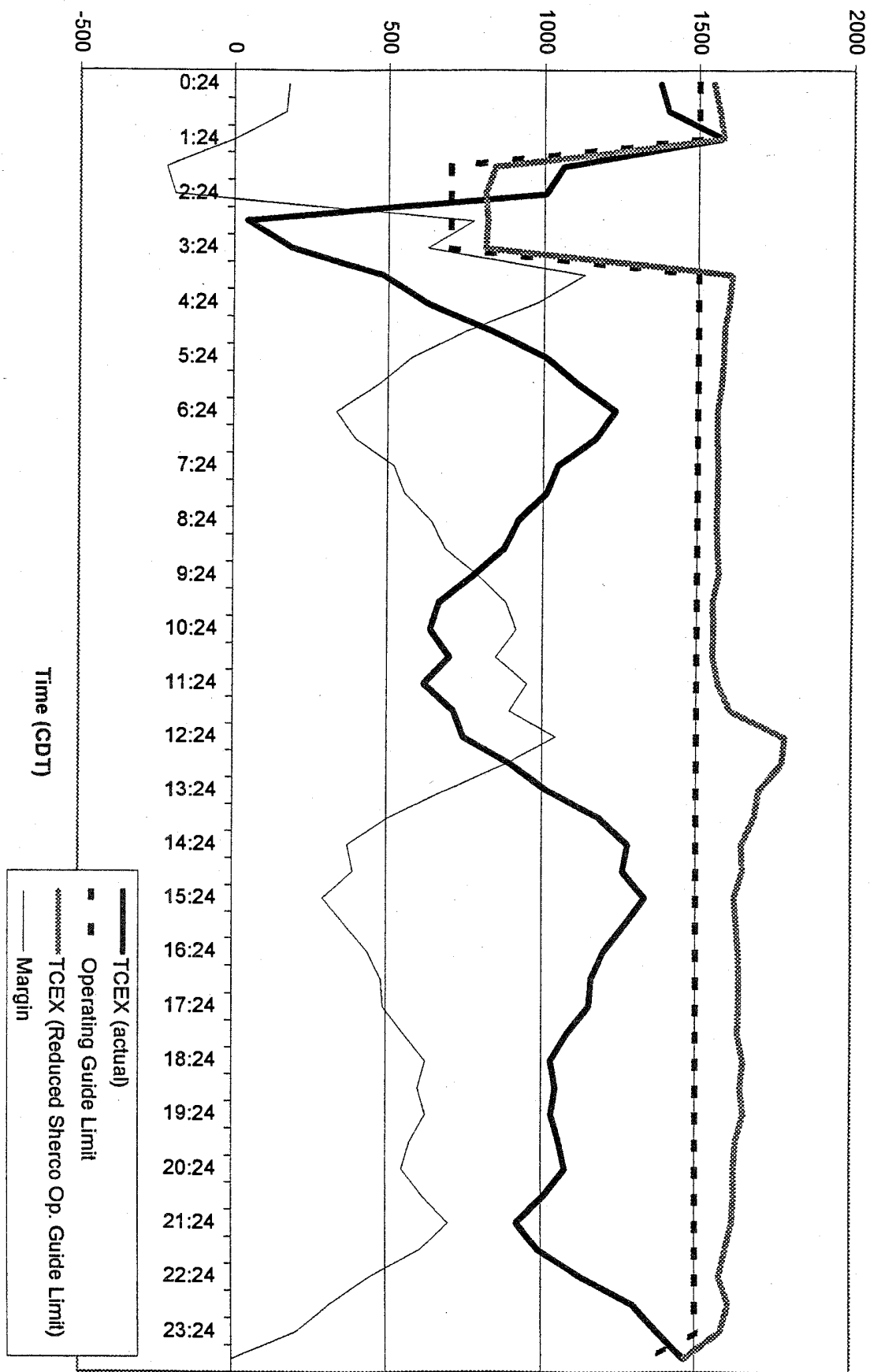


FIGURE #17

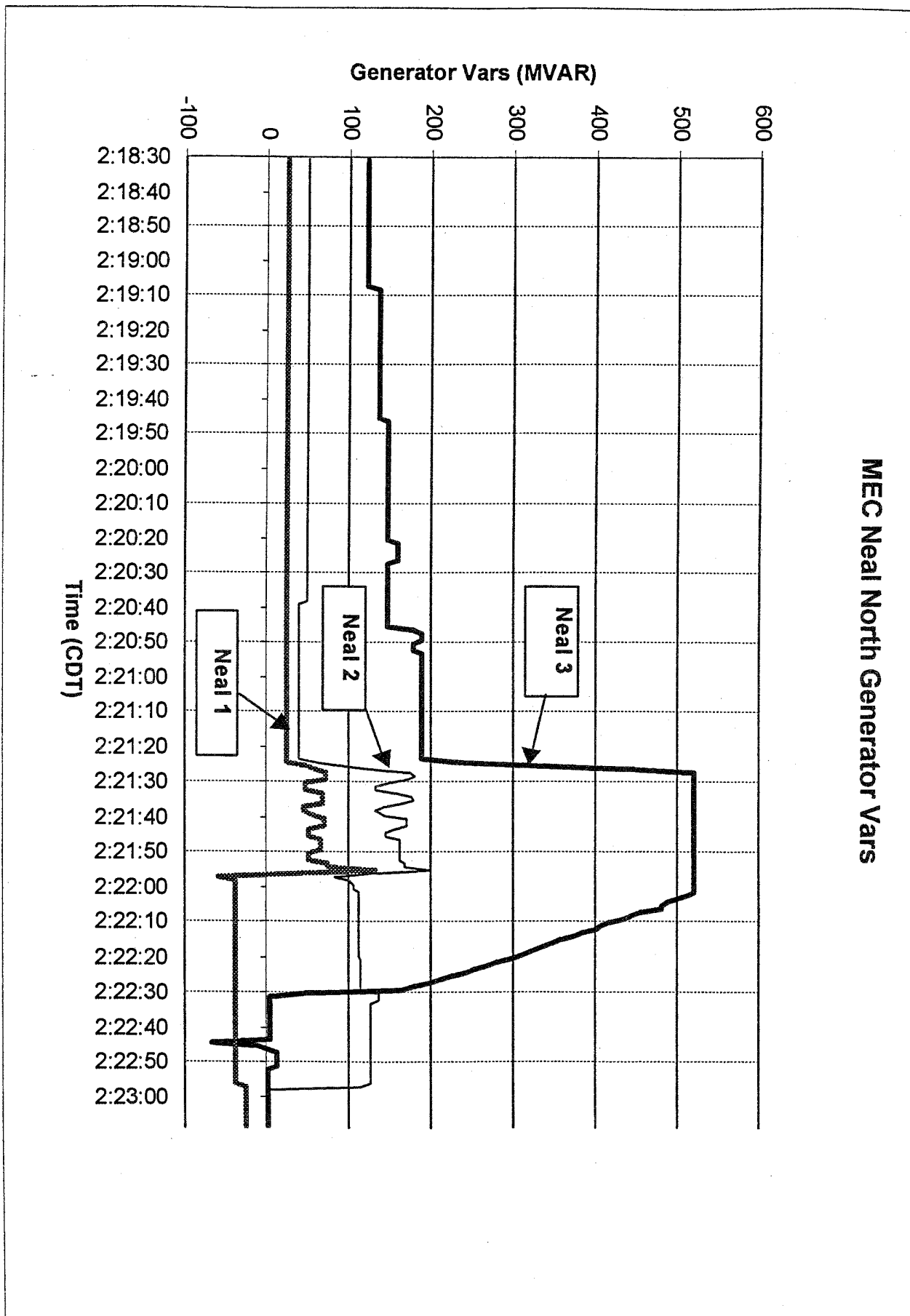
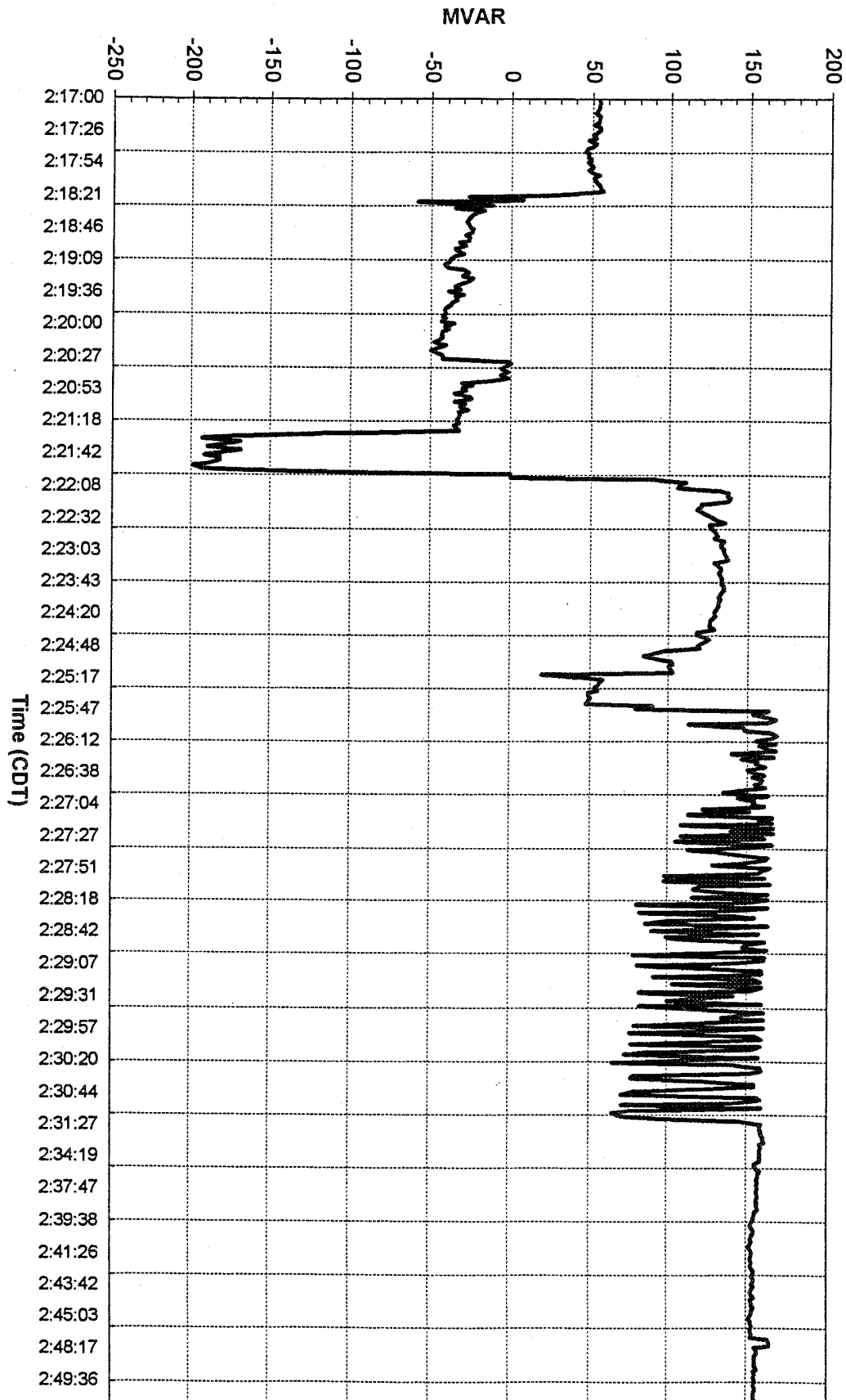


FIGURE #18



Watertown SVS MVAR

FIGURE #19

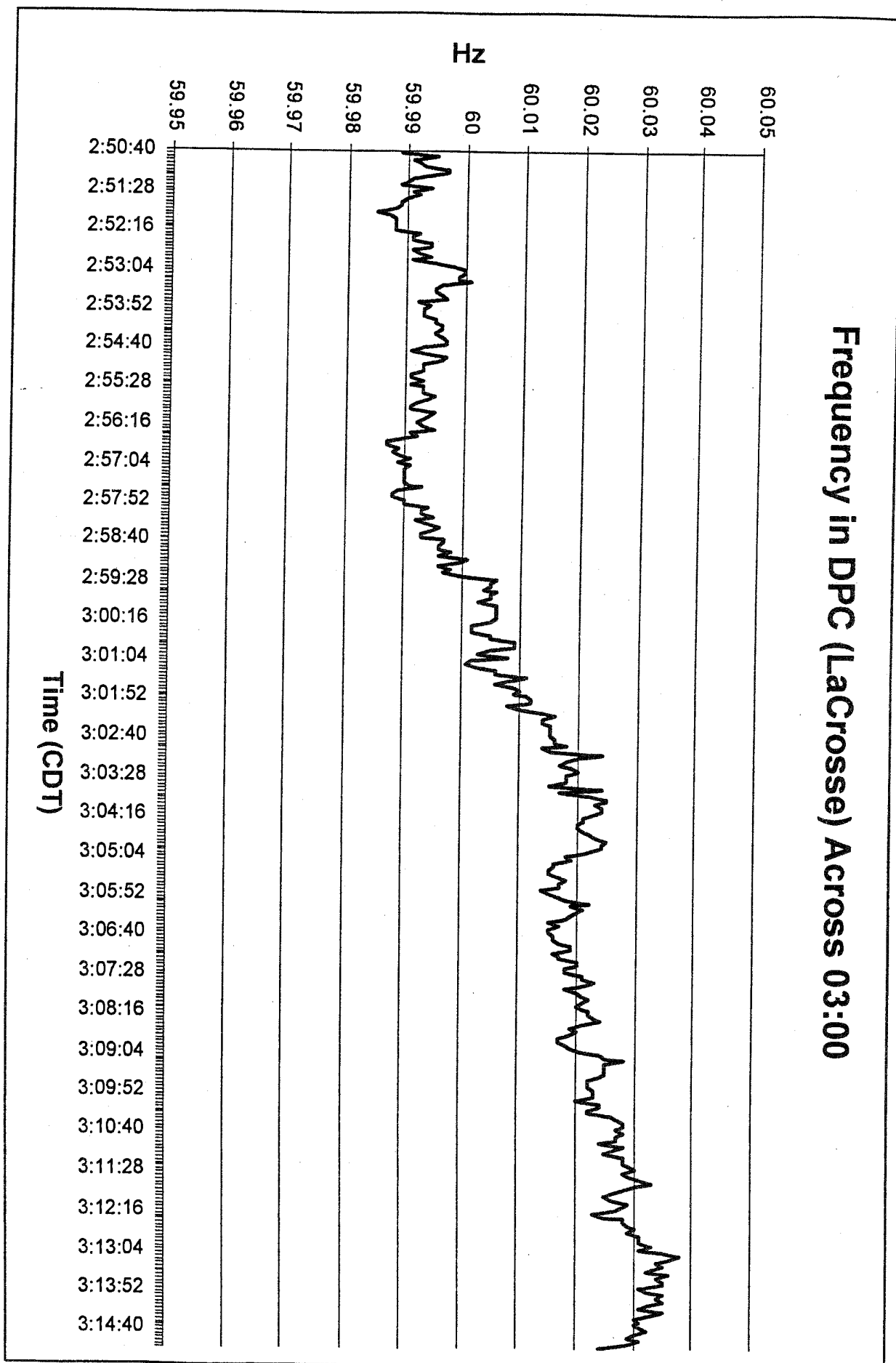
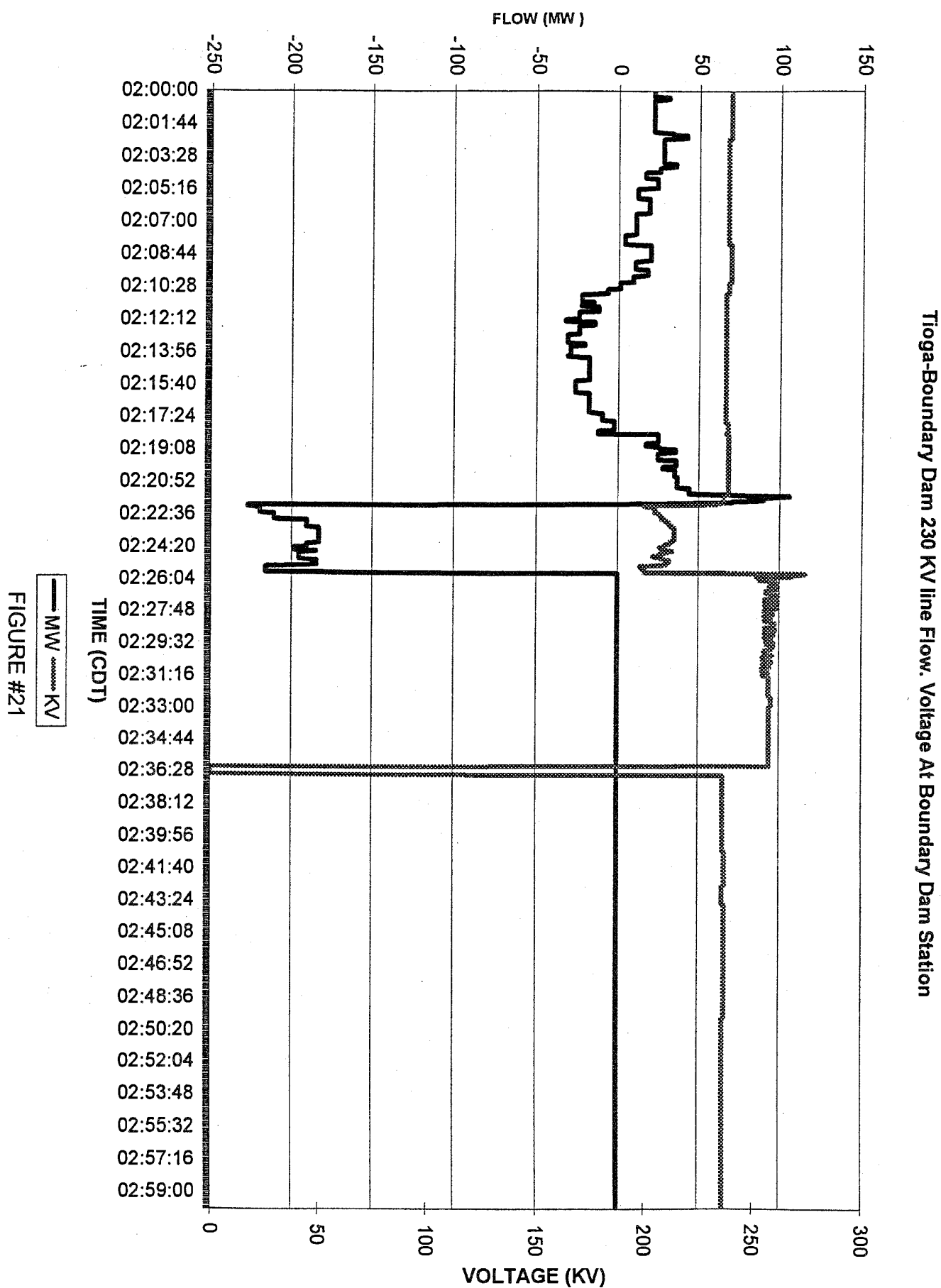


FIGURE #20



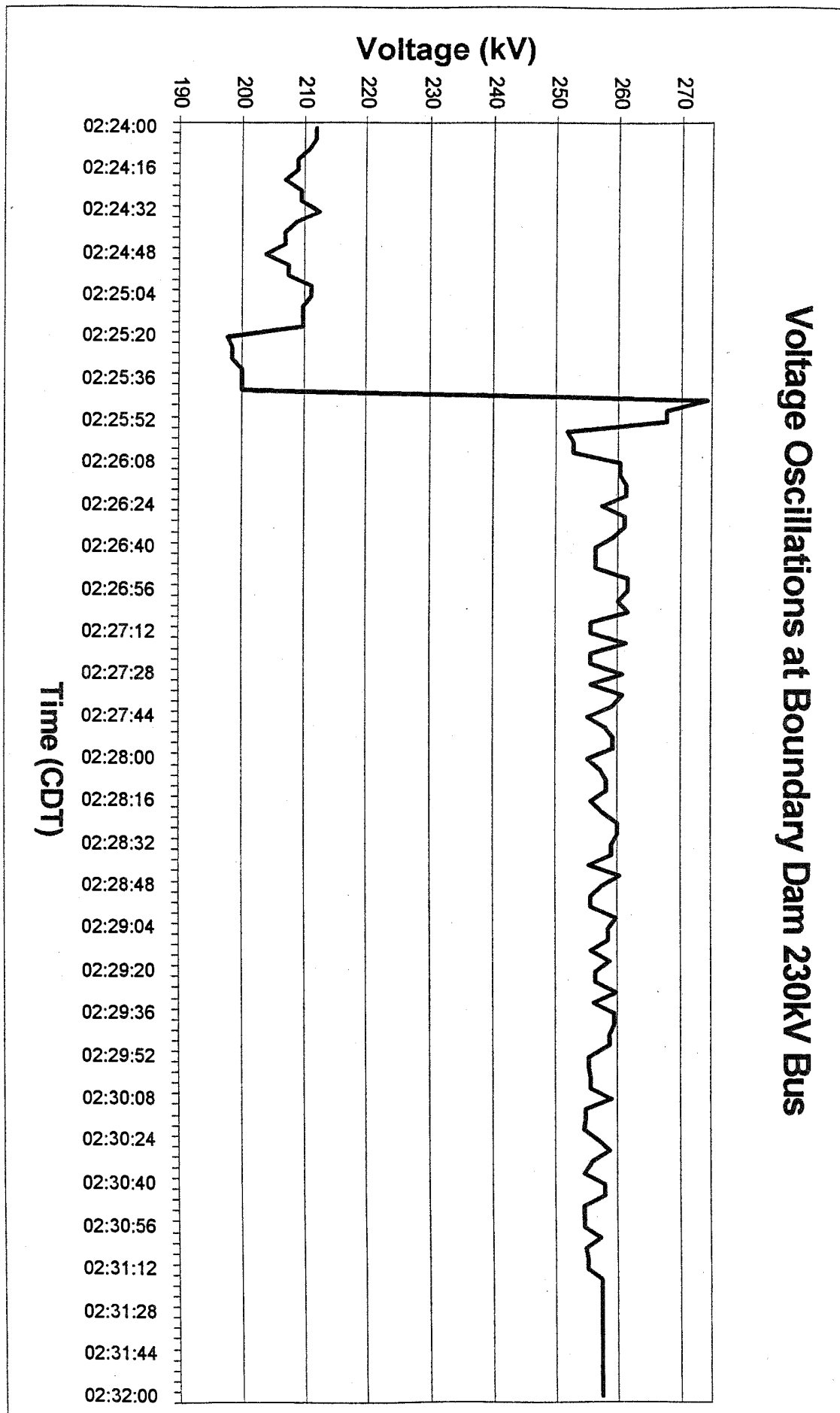
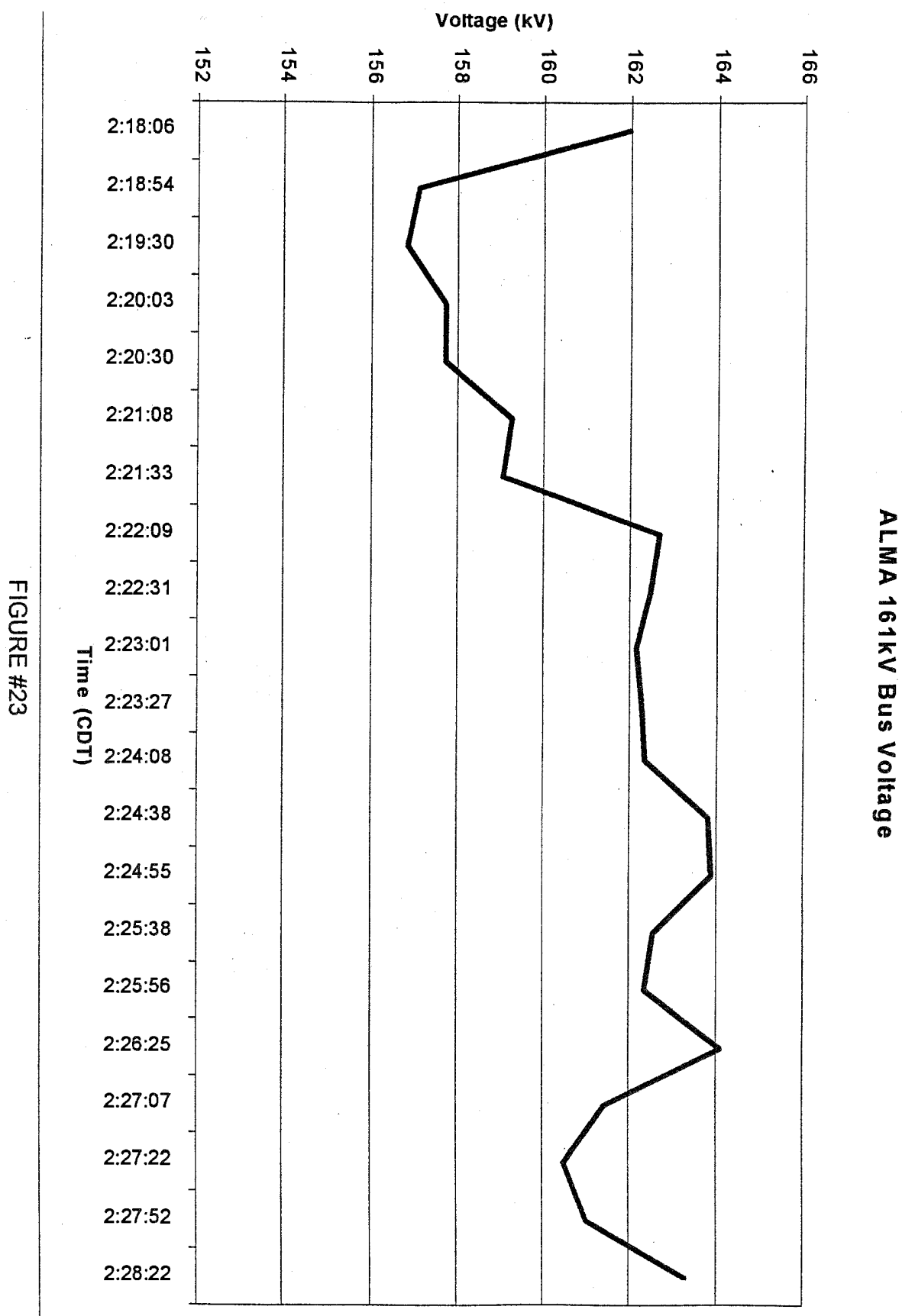


FIGURE #22



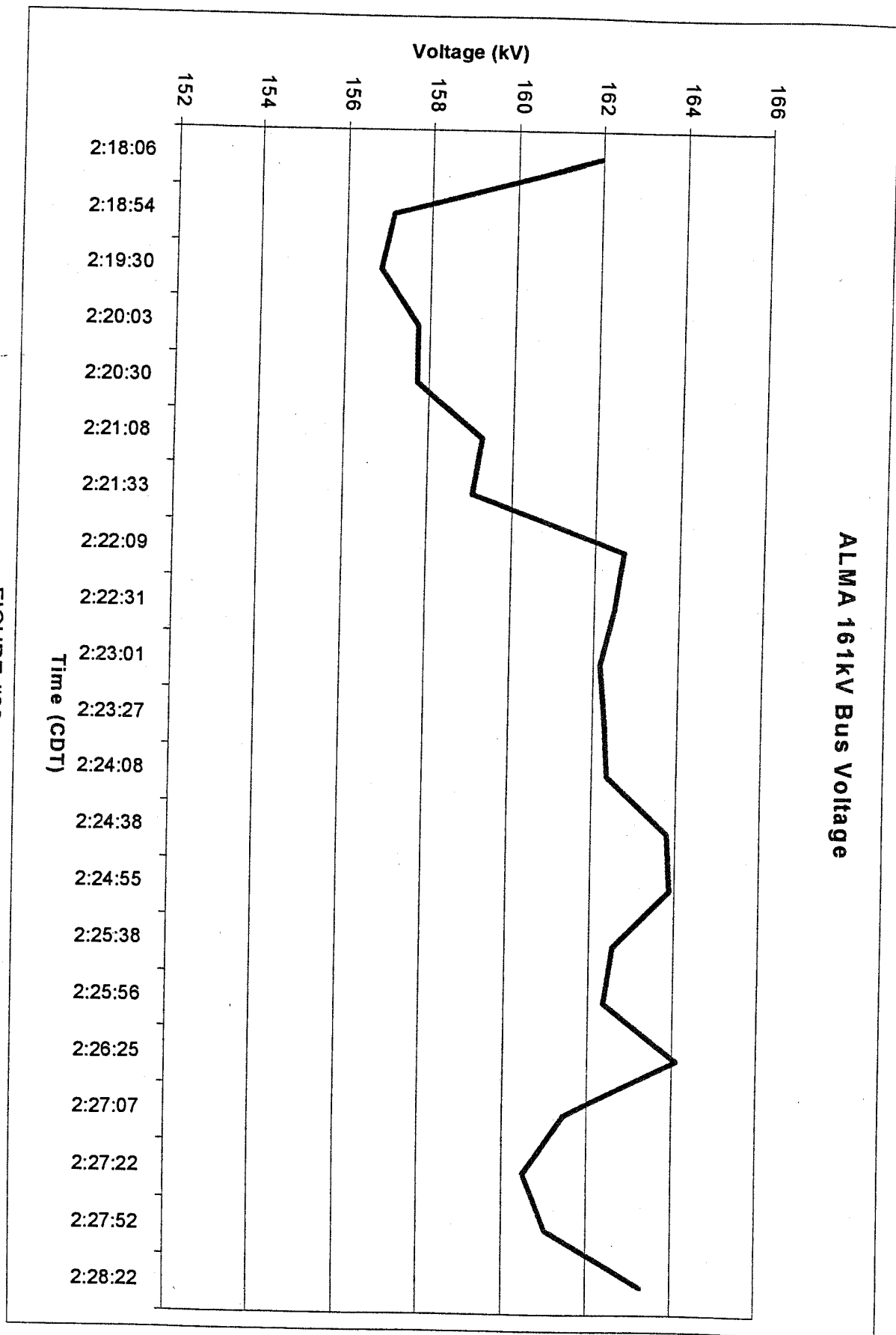


FIGURE #23



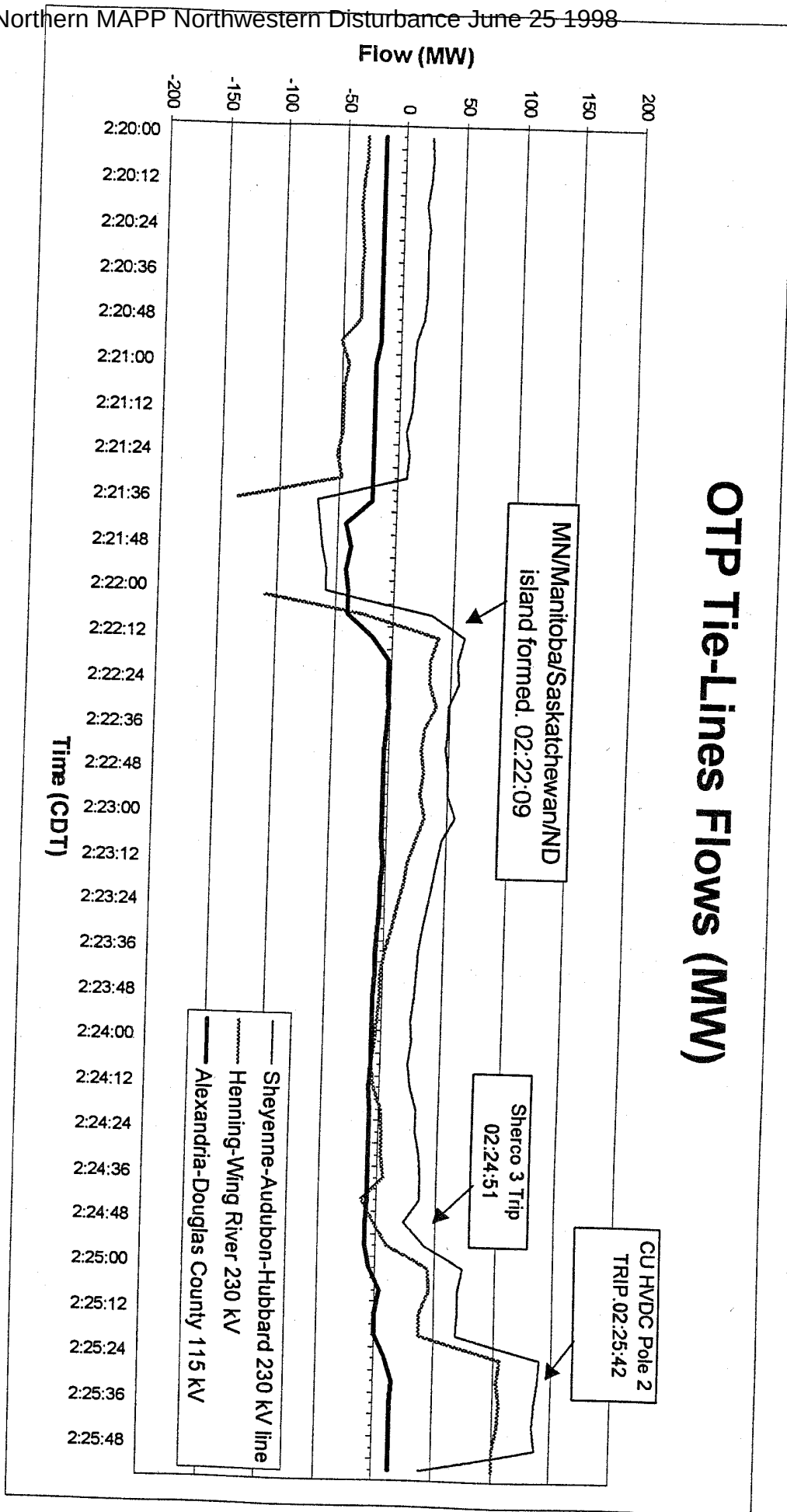
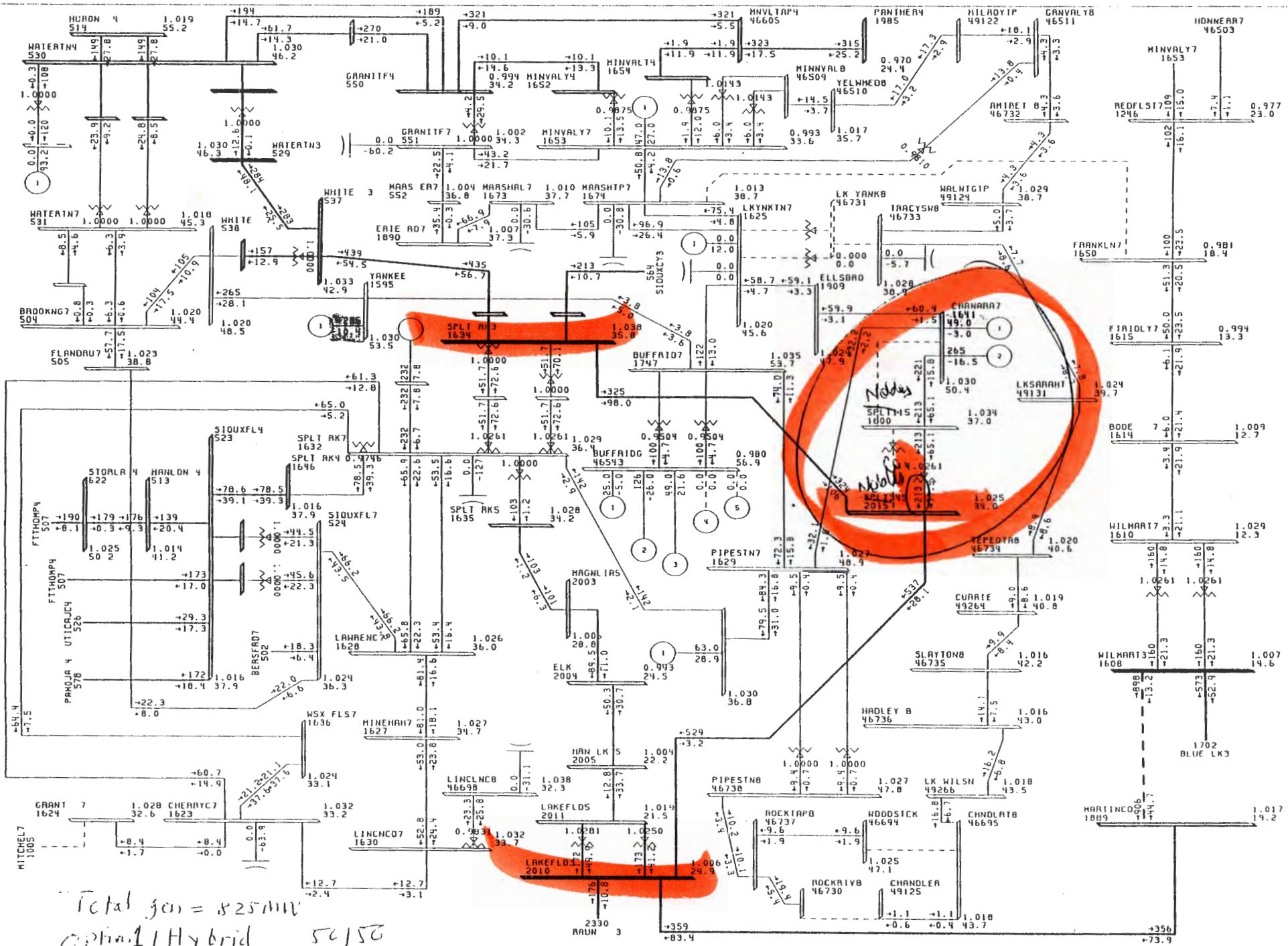


FIGURE #24



## Attachment C - Powerflows Nobles Substation 213 &amp; 302 MVA



Total gen = 825mm  
Optimal Hybrid 50/50

```
OPTION1-YANKEE-BUFFALORIDGE.SAV;DANUBE TO TROY OPEN
ND=1949,MH=2150,MN=1069;0 % AT CHB;50 % AT YANKEE
CHA2-345.DRW    WED, MAY 22 2002  14:06
```

100% RATE  
0.920 UV 1.100 OV  
KV:  $\leq 115$  ,  $\leq 161$  ,  $\leq 230$

|             |                      |
|-------------|----------------------|
| BUS -       | VOLTAGE (PU) / ANGLE |
| BRANCH -    | MW/MVAR              |
| EQUIPMENT - | MW/MVAR              |

Xcel Energy 58

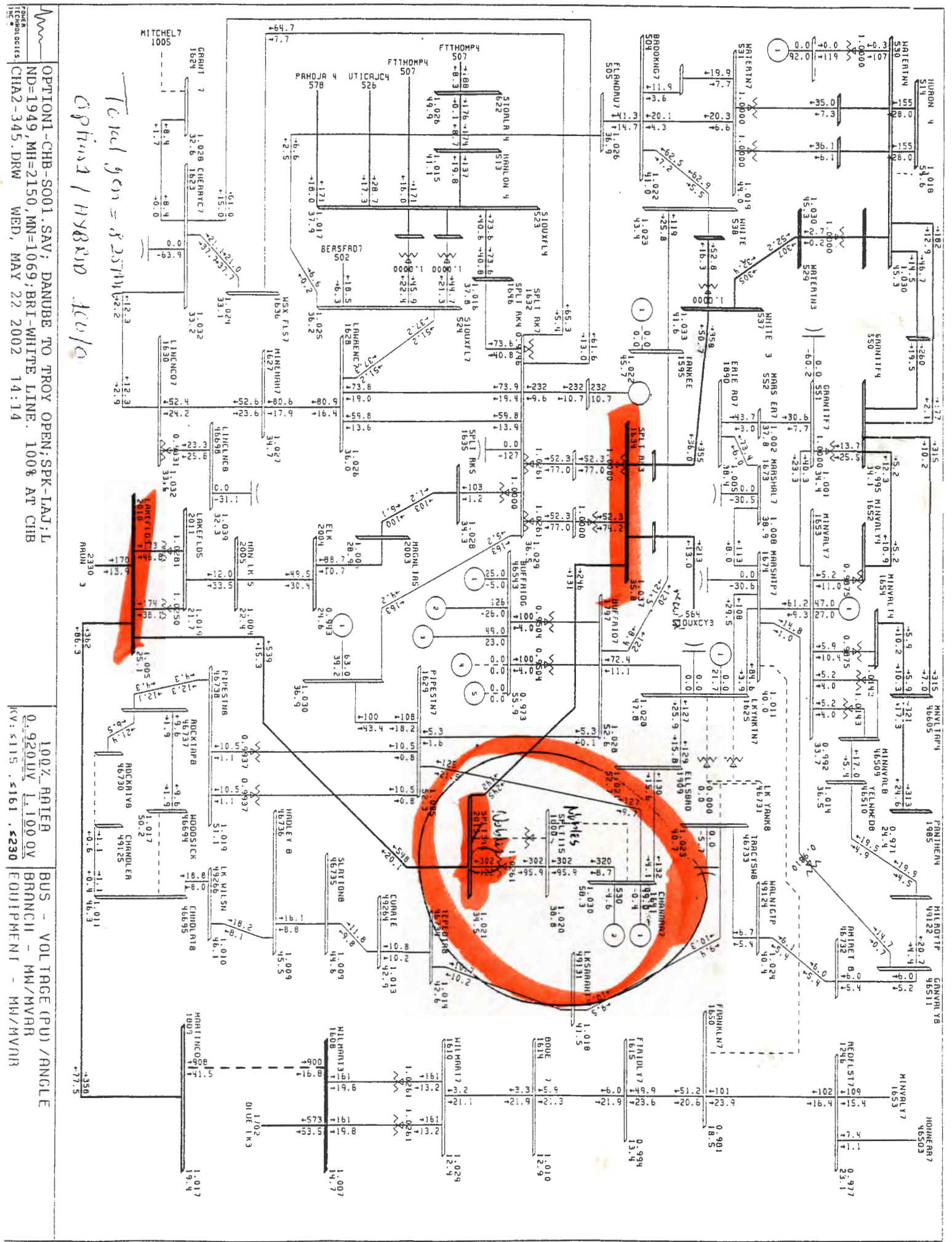




**ABB Project Summary Report**

|               |                                                                         |                   |                                     |           |
|---------------|-------------------------------------------------------------------------|-------------------|-------------------------------------|-----------|
|               | <b><u>LIGNITE VISION 21 PROJECT</u></b>                                 |                   |                                     |           |
| <b>Title:</b> | <b>PHASE II TRANSMISSION SYSTEM<br/>IMPACT STUDY<br/>SUMMARY REPORT</b> | Department<br>ESC | Date<br>Feb 6, 2001<br>Rev. 2-23-01 | Page<br>1 |

|                           |                     |                     |
|---------------------------|---------------------|---------------------|
| <b>Author(s):</b>         | <b>Reviewed by:</b> | <b>Approved by:</b> |
| R.J.Koessler<br>D. Martin |                     |                     |

**Summary:**

Electric Systems Consulting (ESC) of ABB Power T&D Company, Inc., has been contracted by the Lignite Energy Council to study the transmission system requirements for seven potential sites for a new 500-MW coal-fired generating unit in North Dakota. This study developed one to three alternatives for each site with one main alternative for exporting the power from North Dakota to the Minneapolis / St. Paul area. This is only one of many potential alternatives that could be developed and analysis of this alternative was limited to the technical performance to meet MAPP criteria. The evaluation did not consider contractual obligations, prior requests for transmission capacity, analysis of any potential SSR problems, or other commercial and environmental aspects.

This report is a summary of the results of the studies for each of the sites plus the common facilities for all of the sites to export power from North Dakota. For each of the seven sites in North Dakota, alternatives were developed for exporting power from North Dakota to the Minneapolis / St. Paul area. A common set of system upgrades and additions were identified for the sites for increasing the North Dakota Export (NDEX) and transferring the power to the Minneapolis / St. Paul area. The seven sites are shown in the attached diagram and described below by the nearest power system feature.

- Site #1 – Beulah Mine near Coyote Station
- Site #2 – Center Mine near Milton Young Station
- Site #3 – Falkirk Mine near Coal Creek Station
- Site #4 – Freedom Mine near Antelope Valley Station
- Site #5 – Great Northern Properties near Belfield Substation
- Site #6 – Gascoyne Mine near Hettinger Substation
- Site #7 – LUSCAR near Tioga Substation

Initially studies were made for identifying the common facilities required to export 2,450 MW from North Dakota with the new Lignite Vision 21 500-MW power plant. Studies were also made for identifying the facilities required to export 2,800 MW from North Dakota with the new Lignite Vision 21 500-MW power plant plus an additional 350 MW in transmission reservations. The transmission facilities common to all sites for increasing the NDEX to 2450 MW and transmitting the power to Minneapolis/St. Paul are listed as follows:

- Upgrade the operation of the Antelope Valley-Broadland 345 kV line to 500 kV and continue the line to Split Rock. This results in a 409-mile, 500 kV line from Antelope Valley to Split Rock, 299 miles of this 500 kV line will be the result of upgrading the existing A. Valley to Broadland line, which was built for 500 kV, but is currently operated at 345 kV. The remaining 110 miles will be new construction.
- The new 500 kV line is 88% shunt compensated (350 Mvar line shunts at each end of the line using existing 225 Mvar reactors plus new 125 Mvar reactors) to prevent excessive overvoltages during load rejection and energization.
- One 345/500 kV autotransformer (approximately 1,200 MVA) at Antelope Valley and Split Rock.
- A 70-mile, 345 kV circuit between Split Rock and Lakefield Junction.
- For high NDEX transfer scenarios (i.e., the Summer Off-Peak case), a 50-Mvar shunt capacitor at the Groton 345 kV station (to support voltages at that station following outage of the Antelope Valley to Split Rock 500 kV circuit).

Upgrading the Antelope Valley-Broadland 345 kV line to 500 kV and extending it to Split Rock is required to increase the transmission capacity for higher exports and to increase the system stability. Adding a line from Split Rock to Lakefield is required to provide a second 345 kV line to carry power out of the Split Rock (Sioux Falls) area. Without this line, an outage of the Split Rock-Sioux City 345 kV line results in overloads on the 230 kV system. These new lines are shown in the attached map of the electrical system. The new 500 kV line addition from Broadland to Split Rock is colored orange and in bold and the new Split Rock-Lakefield 345 kV line is red and in bold.

The transmission facilities required for increasing the NDEX to 2,800 MW (with generator tripping of the LV21 unit upon outages involving the A.Valley-Split Rock 500 kV line) and transmitting the power to Minneapolis / St. Paul are listed below. Only those facilities that are in addition to or modify the facilities listed above for the 2,450 MW NDEX are listed below (ie. this list is for the incremental facilities).

- 35% series compensation of the Antelope Valley-Split Rock 500 kV line
- 25% series compensation of the Leland Olds-Groton-Split Rock 345 kV line
- 220 Mvars in additional shunt compensation along the Leland Olds to Split Rock 345 kV line.
- A Broadland 500 kV station with a 1,000-MVA 500 / 230 kV transformer
- Line reactor compensation of the proposed 500 kV line is modified to the existing 225-Mvar reactors at Antelope Valley and Broadland

The transmission facilities required for increasing the NDEX to 2,800 MW without generator tripping of the LV21 unit requires additional series capacitors as listed below.

- 35% series compensation of the Antelope Valley-Split Rock 500 kV line
- 65% series compensation of the Leland Olds-Groton-Split Rock 345 kV line
- 65% series compensation of the Leland Olds-Ft. Thompson 345 kV line



The cost estimates for the common facilities to increase the NDEX to 2,450 MW and to 2,800 MW are listed as follows:

|                                                               |               |
|---------------------------------------------------------------|---------------|
| Costs for NDEX Upgrade to 2,450 MW                            | \$130,529,000 |
| Costs for NDEX Upgrade to 2,800 MW With Generator Tripping    | \$153,039,000 |
| Costs for NDEX Upgrade to 2,800 MW Without Generator Tripping | \$162,039,000 |

The confidential site reports identify the facility additions or modifications required for each specific site in addition to those common facilities listed above. These facilities insure that power can be transmitted from the nearby power system station identified in the site list above to the common facilities for a NDEX of 2,450 MW.

Since the three main EHV lines that export power from North Dakota emanate from the Antelope Valley and Leland Olds Stations, the closer the sites are to Antelope Valley and Leland Olds the less miles of transmission lines that need to be built or reinforced to export the power. In general it is required to transmit the power to Antelope Valley and / or Leland Olds Stations or to one of the 345 kV lines that ties into these stations in order to export the power. For some of the sites, alternatives were evaluated for connecting to the local 345 kV or 230 kV systems and enhancing the system to export the power versus building a 345 kV line directly from the site to the Antelope Valley and / or Leland Olds Stations.

Another consideration is the isolation between the generating stations in central North Dakota. The Coal Creek power plant and station is electrically isolated from the Antelope Valley and Leland Olds transmission system. The Coyote and Milton R. Young power plants and stations are also electrically isolated from the Antelope Valley and Leland Olds transmission system. Connecting these systems together generally has an adverse impact on system stability. Alternatives that connect these systems in general will need to increase the system stability by additional enhancements such as series capacitors. Some alternatives also included an Inter-phase Power Controller (IPC) to transmit power between these stations. The IPC transmits power but still results in the station being de-coupled for system faults, that is the IPC does not transmit fault current. This keeps the systems isolated so faults on one system do not excessively impact the other system and therefore do not adversely impact the system stability.

Some of the transmission alternatives for the sites required additional series compensation in the Antelope Valley-Split Rock 500 kV line and / or the Leland Olds-Groton-Split Rock 345 kV line. These alternatives would leave less flexibility to expand the transmission system for future increases in the NDEX. The site studies did identify the total system requirements for each site to insure that each site will meet the MAPP system requirements for steady-state and stability performance.

### **Conclusions:**

Facilities were identified for each site which result in all sites having the capability to export 2,450 MW. The common facilities for increasing the export level to 2,450 MW and to 2,800 MW have been identified for transfers to the Minneapolis / St. Paul area. For these common facilities an estimated cost has been provided. The individual site reports contain the facilities required for each specific site.



**Figure 1: Site Locations Map**

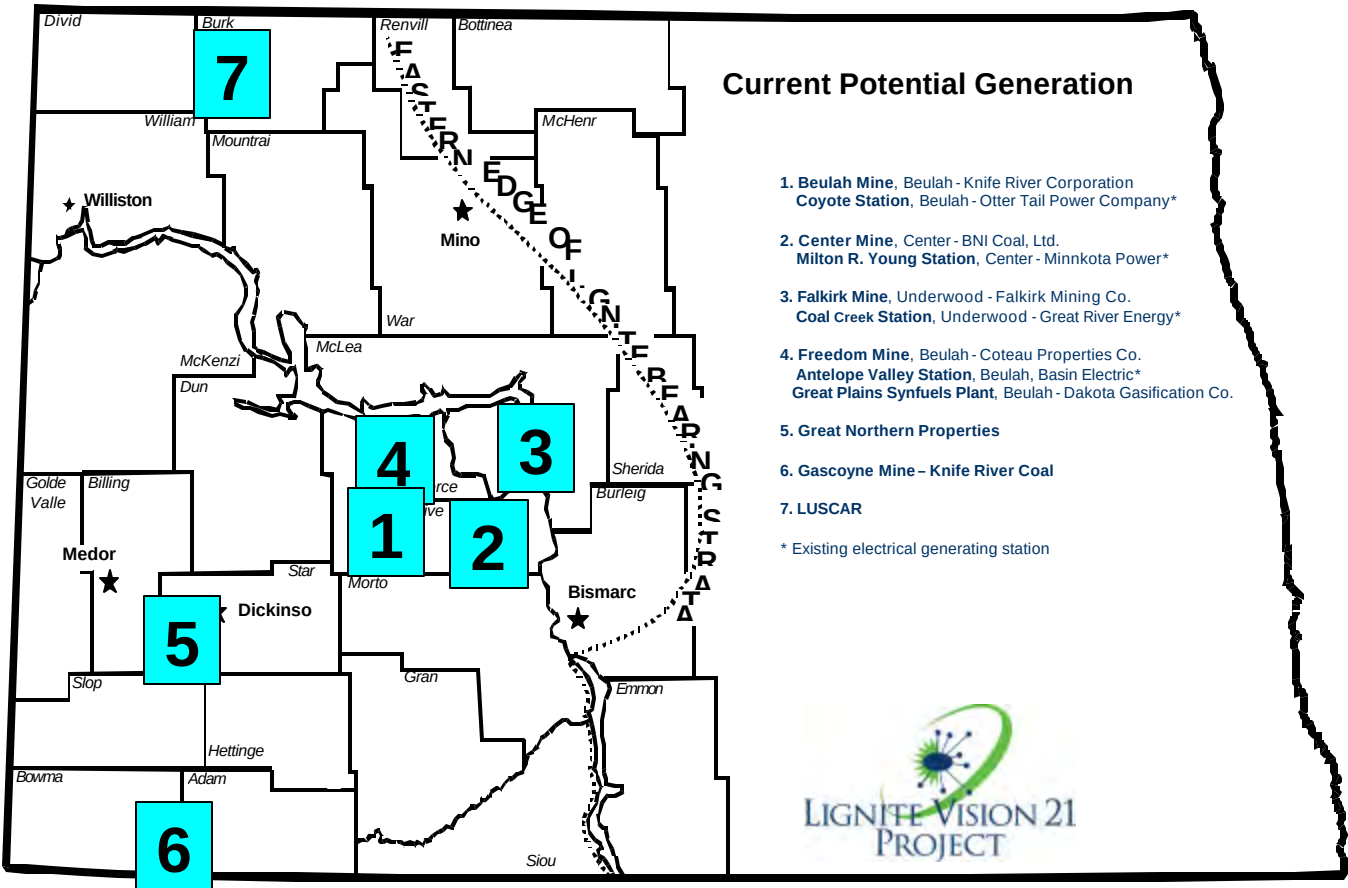


**Figure 2: Transmission Route Map**





**LMFS-99-31**  
**TECHNOLOGY DEVELOPMENT AND MARKETING PLAN FOR THE**  
**LIGNITE VISION 21 PROJECT**

**CONTRACTOR:** Lignite Energy Council

**PRINCIPAL INVESTIGATOR:** John Dwyer  
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Jeff Burgess  
[jburgess@lignite.com](mailto:jburgess@lignite.com)

**CONTRACT AMOUNT:** \$132,000

**Project Schedule – 11 Months**

Contract Date – 6/29/99  
Start Date – 7/1/99  
Completion Date – 6/01/00

**Project Deliverables**

First Quarterly Report – 11/30/99✓  
Draft Final Report – 7/01/00✓  
Final Report – 8/01/00✓

**OBJECTIVE / STATEMENT OF WORK**

The purpose of the Lignite Vision 21 Project (LV 21) is to revitalize growth in the lignite industry. An objective of the LV 21 Technology Development and Marketing Plan is to assist in the development of additional lignite-based electrical generation in North Dakota.

Specific Project Management Objectives for the Phase I LV 21 are:

- establish and maintain project management over the Phase I contracts, activities and support studies;
- coordinate activities of the Advisory Committees providing technical and business expertise and assistance for development and implementation of the Lignite Vision 21 Project;
- identify the most promising advanced lignite-based generation technologies;
- identify environmental and transmission issues and enhancements;
- evaluate innovative alternative extraction technologies;
- develop marketing and development strategies for potential industry and government partners;
- develop a detailed Project Development Phase II plan;
- identify funding for Phase II; and
- develop the marketing, technology and commercialization plan for the Lignite Vision 21 Project.

Specific Advanced Generation Objectives are as follows:

- determine the development status of advanced technology systems;
- identify and describe each advanced technology system;

- identify the characteristics of North Dakota lignite and identify those characteristics that do not penalize and may provide a competitive advantage for North Dakota lignite;
- estimate technical performance and economics; and
- recommend most promising advanced technology system.

## STATUS

Project management of Phase I LV 21 activities were concluded with the successful completion of the four major studies and submission of the Phase II plan. The summary results of the four studies are:

1. Electrical Transmission Study: The Industrial Commission contracted directly with ABB Power and the Lignite Energy Council (LEC) provided project management and supervision for this study. The North Dakota Electric Transmission Study is project LMFS-99-33. ABB identified a transmission route that could accommodate up to 800 MW of additional generation and export from North Dakota. While no existing firm capacity is available for North Dakota export and non-firm capacity is available only part of the time, upgrading of the existing Antelope Valley-Huron line to 500 kV could provide an attractive option to increase North Dakota export. This option should be evaluated in more detail including site-specific consideration and stability studies (see LMFS-99-33 for details).
2. Environmental Enhancement Study: The Industrial Commission contracted directly with Research Data International and the LEC provided project management and supervision for the study. The Environmental Enhancement Study is project LMFS-99-32. The study concluded environmental impacts during construction and operation of a LV 21 power plant are within manageable levels utilizing current emission control technologies (see LMFS-99-32 for details).
3. Advanced Generation Study: The Lignite Energy Council subcontracted with Black & Veatch for the Advanced Generation Technologies Study. The Advanced Generation Study identified pulverized coal fired technology with supercritical steam, circulating fluidized bed and integrated gasification combined cycle as the technologies with the highest probability to meet the LV 21 criteria. Advanced technologies criteria are \$1,000/kW EPC Costs, < 0.15 lbs NO<sub>x</sub>/MBtu, and 0.18 lbs/MBtu SO<sub>2</sub>. Additional criteria and performance standards are presented in the report.
4. Alternative Lignite Extraction Technologies: The Industrial Commission contracted directly with Dakota Gasification Company (DGC) and the LEC provided project coordination and review. The Alternative Lignite Extraction Technologies study is project LMFS-99-30. The study identified underground coal gasification, a concept called LANL and coal-bed methane as alternative technologies that warranted further study.

The contractor, Lignite Energy Council, in consultation with industry/state agency advisory panels, developed a detailed project plan for LV 21 Phase II. Activities for Phase II are project management, identification of wholesale customers and equity owners, marketing activities and planning for Phase III.



**LMFS-99-33**  
**NORTH DAKOTA ELECTRIC TRANSMISSION STUDY**

**CONTRACTOR:** ABB Power T&D Company, Inc.

**PRINCIPAL INVESTIGATOR:** Don Martin  
(919) 856-2463 (O)  
(919) 807-5060 (fax)  
[don.e.martin@us.abb.com](mailto:don.e.martin@us.abb.com)

**CONTRACT AMOUNT:** \$75,000

**Project Schedule – 6 Months**

Contract Date – 8/13/99  
Start Date – 9/15/99  
Completion Date – 3/15/00

**Project Deliverables**

Draft Final Report – 3/01/00✓  
Final Report – 5/15/00✓

**OBJECTIVE / STATEMENT OF WORK**

The purpose of this project is to evaluate the transmission capability for North Dakota considering future load growth and potential generation additions. The present and near term electrical transmission system, export of generation and capacity for additional export from North Dakota are evaluated. Specific objectives are:

- Determine the limitations of the existing bulk electric transmission network to provide transmission service to existing electrical load and generating facilities in North Dakota.
- Identify future electric load serving requirements and the possible enhanced capabilities (through increased efficiencies and minor improvements) of existing generating facilities in North Dakota.
- Identify and evaluate possible bulk transmission enhancements necessary to serve future electric load and the enhanced capabilities (through increased efficiencies and minor improvements) of existing generating facilities in North Dakota.
- Identify and evaluate possible bulk transmission enhancements necessary to provide additional transmission outlet capability for new coal-fired generating units that might be constructed in North Dakota.

**STATUS**

The existing ac transmission system has the capability to export over 2000 MW from North Dakota. The transmission limits for power exported from North Dakota are not due to thermal limits of the lines or equipment but are due to stability and voltage collapse limitations on the power system. Transfer capability from North Dakota on the ac system is also dependent on simultaneous transfer from Manitoba Hydro.

ABB completed an initial Industrial Commission funded study in 1993, "Technical and Economic Assessment of Options for Increasing Transmission Capacity from the State of North Dakota" (LMFS-7). ABB concluded that although there appeared to be spare capacity on the North Dakota transmission system, once all outages, transmission fluctuation and other factors were considered the level of spare capacity is sparse.

Local utilities emphasize that no existing firm capacity is available for North Dakota Export (NDEX) and non-firm capacity is available only part of the time.

As a part of project LMFS-99-33, ABB evaluated options to enhance NDEX. Series capacitor compensation to enhance existing transmission was one option investigated to increase export from North Dakota. The analysis indicates series capacitors provide potential for increasing NDEX, but additional study is needed to evaluate system performance and stability.

Export from an additional 500 MW of North Dakota generation appears feasible by upgrading the existing lines. Upgrading the existing lines from Antelope Valley, North Dakota to Huron, South Dakota to 500kV and the Huron, South Dakota to Split Rock, South Dakota and Split Rock, South Dakota, to Lakefield, Minnesota line to 345kV, would provide a path for power to the Twin Cities area of Minnesota.

Additional options are new high voltage direct current (HVDC) lines, upgrading existing HVDC lines and a new 230 kV line to Fort Thompson, South Dakota.

As a result of project LMFS-99-33, site-specific transmission analyses are recommended.





Multi-Value Project Dashboard

Tranche 2.1 Portfolio

WOLF Attachment E - Multi-Value Project Dashboard

| #  | Project Name                                                       | State      | Estimated In Service Date |              | Status                  |        | Cost                   |                                | Notes                     |
|----|--------------------------------------------------------------------|------------|---------------------------|--------------|-------------------------|--------|------------------------|--------------------------------|---------------------------|
|    |                                                                    |            | MTEP Approved             | Current Date | State Regulatory Status | Const. | MTEP Approved (2024\$) | Q4 2025 (2024\$; unless noted) |                           |
| 19 | Bison - Alexandria                                                 | MN; ND     | 2032                      | 2032         | <div></div>             |        | \$216                  | \$337*                         | Cost change under review. |
| 20 | Maple River - Cuyuna                                               | MN; ND     | 2033                      | 2033         | <div></div>             |        | \$908                  | \$1107*                        |                           |
| 21 | Iron Range - Arrowhead                                             | MN; WI     | 2032                      | 2032         | <div></div>             |        | \$428                  | \$499*                         |                           |
| 22 | Big Stone South - Brookings County - Lakefield Junction            | MN; SD     | 2034                      | 2034         | <div></div>             |        | \$1,459                | \$1739*                        |                           |
| 23 | Lakefield Junction - East Adair                                    | IA; MN     | 2034                      | 2034         | <div></div>             |        | \$1,375                | \$1398*                        |                           |
| 24 | Lakefield Junction - Pleasant Valley - North Rochester             | MN         | 2034                      | 2034         | <div></div>             |        | \$1,195                | \$1955*                        | Cost change under review. |
| 25 | Pleasant Valley - North Rochester - Hampton Corner                 | MN         | 2032                      | 2032         | <div></div>             |        | \$222                  | \$241*                         |                           |
| 26 | North Rochester - Columbia                                         | MN; WI     | 2034                      | 2034         | <div></div>             |        | \$1,924                | \$1873*                        |                           |
| 27 | Rocky Run - Werner - North Appleton                                | WI         | 2032                      | 2032         | <div></div>             |        | \$212                  | \$212                          |                           |
| 28 | South Fond du Lac - Rockdale - Big Bend - Sugar Creek - Kitty Hawk | WI         | 2033                      | 2033         | <div></div>             |        | \$1,102                | \$1102                         |                           |
| 29 | Bluemound - Arcadian - Waukesha - Muskego - Elm Road - Racine      | WI         | 2032                      | 2032         | <div></div>             |        | \$731                  | \$731                          |                           |
| 30 | Columbia - Sugar Creek                                             | WI         | 2034                      | 2034         | <div></div>             |        | \$743                  | \$686                          |                           |
| 31 | Sugar Creek - Collins                                              | IL; WI     | 2034                      | 2034         | <div></div>             |        | \$733                  | \$807                          |                           |
| 32 | Ludington - Denver - Tittabawassee & Nelson Road                   | MI         | 2032                      | 2032         | <div></div>             |        | \$1,553                | \$1553                         |                           |
| 33 | Greentown - Sorenson - Lulu                                        | IN; MI     | 2033                      | 2033         | <div></div>             |        | \$1,310                | \$1310                         |                           |
| 34 | Oneida - Sabine Lake - Blackfoot & Majestic                        | MI         | 2032                      | 2032         | <div></div>             |        | \$600                  | \$600                          |                           |
| 35 | Southwest Indiana-Kentucky                                         | IN; KY     | 2032                      | 2032         | <div></div>             |        | \$743                  | \$748*                         |                           |
| 36 | Southeast Indiana                                                  | IN; OH     | 2032                      | 2032         | <div></div>             |        | \$578                  | \$578                          |                           |
| 37 | Maywood - Belleau - MRPD - Sioux - Bugle                           | IL; MO     | 2032                      | 2032         | <div></div>             |        | \$881                  | \$881                          |                           |
| 38 | East Adair - Marshalltown - Sub T                                  | IA         | 2034                      | 2034         | <div></div>             |        | \$1,583                | \$1583                         |                           |
| 39 | Lehigh - Marshalltown - Franklin North & Montezuma                 | IA         | 2032                      | 2032         | <div></div>             |        | \$588                  | \$588                          |                           |
| 40 | Sub T - Woodford County - Collins & Reynolds                       | IA; IL; IN | 2034                      | 2034         | <div></div>             |        | \$2,298                | \$2298                         |                           |
| 41 | Woodford County - Fargo & Radbourn                                 | IL         | 2032                      | 2032         | <div></div>             |        | \$422                  | \$422                          |                           |
| 42 | Burr Oak - Schahfer                                                | IN         | 2032                      | 2032         | <div></div>             |        | \$68                   | \$68                           |                           |

\*Some or all facilities reported in nominal (year of occurrence) dollars.

|       |          |          |
|-------|----------|----------|
| Total | \$21,868 | \$23,314 |
|-------|----------|----------|

| State Regulatory Status Indicator Scale |                                                                   |
|-----------------------------------------|-------------------------------------------------------------------|
| <div></div>                             | Pending                                                           |
| <div></div>                             | In Regulatory Process or partially complete                       |
| <div></div>                             | Regulatory Process complete or no regulatory process requirements |



# 2025 HVDC IMPACT ASSESSMENT



December 2025

## HIGHLIGHTS

- Multiple factors, including the increase in renewable generation, economics, and merchant-based HVDC transmission projects, are driving MISO's need to understand impact and identify work required to incorporate planned and future facilities into MISO's planning, operations, and markets.
- This impact assessment has several focus areas aligned with MISO stakeholder-informed key questions, including markets, reliability operations, resource adequacy, interconnection of merchant HVDC, and expansion planning of intraregional lines.
- Based on the impact assessment, recommendations of future work are identified. These will be prioritized alongside non-HVDC work items when updating MISO's roadmap.



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# Preface

The electric power sector is experiencing unprecedented changes. Renewable resources represent an increasing portion of the generation portfolio, necessitating greater amounts of energy to be transmitted over longer distances than in the past. Demand is rising faster than it has in decades, driven by data centers and computing loads, electrification, and advanced manufacturing. At the same time, aging traditional “baseload” generation resources are facing retirement, while new dispatchable resources require long lead times for construction.

Utilities and grid operators are exploring ways to meet energy adequacy and reliability obligations, leveraging new technologies like storage and innovative solutions such as demand response programs. One of these alternatives, merchant High Voltage Direct Current (HVDC), is being proposed to increase transfer capabilities, given HVDC’s ability to support long-distance transfer, flow control, and ancillary service benefits. MISO is seeing interest in both merchant-led and regionally planned HVDC projects. MISO’s Merchant HVDC (MHVDC) Interconnection Queue currently contains three projects — North Plains Connector, Grain Belt Express, and SOO Green — with planned commercial operation in the 2030-32 timeframe. In parallel, utility-led, non-merchant HVDC projects are advancing. For example, Minnesota Power is modernizing the Square Butte HVDC line to incorporate voltage source converter (VSC) technology, enhancing controllability and grid support capabilities within MISO’s footprint.

MISO and its stakeholders recognize the opportunities HVDC brings and its cross-cutting impact on all four of MISO’s [Reliability Imperative](#) pillars: Market Redefinition, Operations of the Future, System Enhancements, and future Transmission Evolution. Stakeholders have requested MISO prioritize initiatives related to HVDC facilities, as reflected in the MISO Dashboard issues [MSC-2024-8](#) (Incorporating HVDC in Energy and Ancillary Services Market Operations, as well as Transmission Planning) and [RASC-2024-5](#) (Capacity Accreditation for External Resources facilitated by HVDC Transmission).

This paper presents an impact assessment of HVDC and provides initial recommendations for future work across MISO’s markets, reliability operations, resource adequacy, and planning organizations. Each section of the assessment briefly examines current practices, summarizes the analyses performed to understand HVDC impacts, and highlights key recommendations stemming from assessment insights.

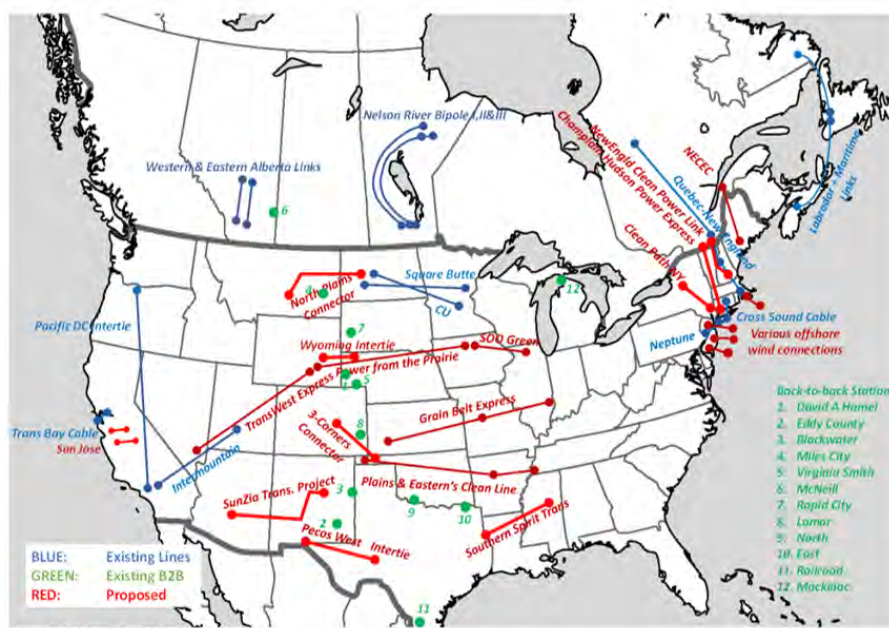


# Executive Summary

High Voltage Direct Current (HVDC) transmission spans all four of MISO's Reliability Imperative pillars: Market Redefinition, Operations of the Future, System Enhancements, and Transmission Evolution. Increasing renewable generation, economic factors, and merchant-based HVDC transmission projects are driving the need for MISO to understand the impact across those pillars and identify work necessary to incorporate planned and future facilities into MISO's planning, operations, and markets.

Figure 1 illustrates the volume and region of proposed HVDC across the United States and Canada as of November 2024. Within MISO, there are currently several operational HVDC facilities: Coal Creek to Dickinson (noted as CU in the figure), Square Butte – Arrowhead, Manitoba Hydro Forbes/Nelson River Bipoles I, II and III; and Mackinac back-to-back. Proposed HVDC lines to be connected to MISO include the merchant HVDC projects Grain Belt Express, Southern Spirit (application withdrawn), North Plains Connector, SOO Green, and an upgrade to the Square Butte – Arrowhead facility.

HVDC stakeholders have requested MISO prioritize initiatives related to HVDC facilities, as reflected in the MISO Dashboard issues [MSC-2024-8](#) (Incorporating HVDC in Energy and Ancillary Services Market Operations, as well as Transmission Planning) and [RASC-2024-5](#) (Capacity Accreditation for External Resources facilitated by HVDC Transmission). During the April 29, 2025, [HVDC Assessment Workshop](#), MISO and stakeholders identified key questions to define the focus areas for the 2025 impact assessment.



Ref: MISO HVDC Analysis Process for MTEP and LRTP, OMS MHVDC Workshop, April 2024  
Updated November 2024  
Used with permission from Dr. McCalley, Iowa State University

**Figure 1: Existing and Planned HVDC in the United States and Canada**



This paper describes the HVDC impact assessment and provides recommendations for future work across markets, reliability operations, resource adequacy, and planning. Each section briefly examines current practices, summarizes the analyses performed to understand HVDC impacts, and highlights key recommendations stemming from assessment insights. HVDC recommendations will be considered alongside other non-HVDC work items when updating MISO's Roadmap.

While the HVDC recommendations are not time-bound, they reflect three levels of priority. Recommendations beginning with:

- *"MISO should"* are high priority relative to other HVDC recommendations. These actions address reliability concerns or stakeholder priority.
- *"As HVDC penetration increases, MISO should"* are medium priority relative to other HVDC recommendations, with the need linked to further deployment of HVDC facilities within MISO. These actions can wait until planned HVDC facilities advance further in their development.
- *"MISO could"* are lower priority. These represent issues and ideas identified during MISO's assessment that might have value but are not necessarily pressing.

## MARKETS

MISO currently supports three HVDC participation models: generation lead lines, manually scheduled reliability assets, and external asynchronous resources (EARs). These models were developed on a case-by-case basis to address specific operational needs and do not constitute a unified framework for dispatchable HVDC integration. All existing HVDC facilities either operate within MISO's footprint or connect to asynchronous systems, such as Manitoba Hydro. MISO has no precedent for dispatchable HVDC connecting its system to synchronized, market-based neighbors like PJM or SPP.

### INTRA-REGIONAL HVDC OPTIMIZATION

In principle, HVDC flows could be co-optimized with generation and load in MISO's market systems. MISO presented initial conceptual formulations 2021 and subsequently collaborated with the National Laboratory of the Rockies (NLR)<sup>1</sup> to conduct simulations, which performed well under positive pricing but revealed challenges such as circular flows and loss-maximizing behavior under negative prices.

#### Other RTOs have addressed similar challenges:

- As a transmission asset under CAISO's operational control, the Trans Bay Cable is integrated into 5-minute Security Constrained Economic Dispatch (SCED), although HVDC losses are not modeled explicitly.
- NYISO's proposed approach excludes internal controllable lines from TCC (Transmission Congestion Contract) markets to maintain dispatch flexibility.

MISO will continue collaborating with NLR to develop constraints that prevent circular flows and to evaluate alternative approaches for modeling HVDC losses.

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<sup>1</sup> MISO is collaborating with NLR on a range of research initiatives, including HVDC modeling, market integration, and the development of interregional coordination frameworks.



## INTERREGIONAL HVDC COORDINATION AND RESOURCE PARTICIPATION

Currently two interregional coordination processes are active in MISO. The Market-to-Market (M2M) process facilitates coordination between MISO and neighboring markets to manage congestion on AC flowgates impacted by both markets in a cost-effective manner. The Coordinated Transaction Scheduling (CTS) process is designed to support cost-reducing interchange transactions<sup>2</sup> that reflect real-time price differences between markets. These processes were developed with non-controllable AC networks in mind.

Interregional coordination processes could be enhanced to identify opportunities for real-time congestion relief and more efficient interchange through controllable HVDC. These processes could evolve through graduated approaches tailored to dispatch authority, operational goals, and the participation of external resources enabled by HVDC. How these resources participate in MISO's markets (e.g., via pseudo-tie or EAR models) would depend on the coordination approach and project-specific characteristics. The following three approaches reflect a progression from status quo toward increasing levels of coordination and complexity.

| Level 0<br>HVDC Owner Operates the Line<br>(Status quo)                                                                                                                                                                                                                                                                                                                                                            | Level 1<br>Single RTO Dispatches for M2M<br>Congestion Relief                                                                                                                                                                                                                                                                                                                                       | Level 2<br>Dynamic Interchange Optimization                                                                                                                                                                                                                                                                                                                                                                         |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| The HVDC owner independently dispatches the line with no control from MISO or neighboring RTOs. HVDC flows are treated as fixed interchange and excluded from economic redispatch in both markets, with M2M continuing to identify generation redispatch solutions for congestion management. If HVDC contributes to congestion and generation relief is insufficient, only reliability-based curtailment remains. | One of the RTOs dispatches HVDC for internal optimization and for M2M congestion relief. This may require coordinating neighbors to exchange additional information beyond the shadow prices currently exchanged. Sharing relief cost curves, HVDC availability, ramp rates, and real-time congestion relief potential may be necessary to fully leverage HVDC controllability in M2M coordination. | One of the RTOs dispatches the HVDC line to vary interchange schedules across intervals (in contrast to Level 1, where net interchange is fixed). This requires both RTOs to coordinate on interchange accounting and power balancing, as HVDC flows directly affect power balance and transmission constraints in both systems. This approach offers flexibility but introduces additional operational complexity. |

## RECOMMENDATIONS

This assessment identifies three areas for potential enhancement to support efficient integration of HVDC into MISO's markets:

### 1. Interchange and market-to-market congestion management processes

Under current interchange and M2M coordination processes, large interregional HVDC facilities could complicate balancing and AC congestion management. While interchange schedules that threaten reliability can be interrupted using the Transmission Loading Relief (TLR) process, such interruptions are costly. Enhancing interchange and market-to-market coordination processes to

<sup>2</sup> Most interregional transactions are scheduled by market participants via e-Tags. While essential, these do not provide the operator-level coordination described here.

explicitly account for HVDC would allow these facilities to be controlled or incentivized to cost effectively mitigate energy imbalances and AC congestion, rather than exacerbating them.

*As penetration of HVDC increases, MISO should evaluate approaches to integrate HVDC into interchange and market-to-market congestion management processes and discuss these approaches with neighboring RTOs.*

## **2. Intra-regional HVDC in market and operations processes**

Under current market and operations processes, intra-regional HVDC facilities are generally not scheduled by MISO and can exacerbate AC system congestion. Integrating HVDC scheduling into dispatch and commitment processes would allow MISO to use these facilities to manage congestion rather than worsen it. Full integration is complicated by the potential for fully optimized HVDC schedules to drive circular flows, large angle differences between buses, swings in AC loss factors, unphysical bi-directional modeled flows, and increased overall losses.

Near-term implementation could leverage CAISO's operational experience with five-minute dispatch, as well as NYISO's proposed framework for treating controllable lines as resources. *As HVDC penetration increases, MISO should evaluate these potential approaches to partially integrate intra-regional HVDC into market and operations practices. Additionally, MISO could continue researching open questions related to full integration.*

## **3. HVDC in congestion hedging processes**

HVDC schedules in the FTR auctions impact the simultaneously feasible FTRs that can be cleared. When HVDC schedules differ between the FTR auctions and the day-ahead market under substantially similar conditions, auction-cleared FTRs may not be simultaneously feasible in day-ahead, potentially leading to underfunding. Additionally, inflexible scheduling of HVDC in the FTR auctions may reduce hedging opportunities. These challenges are compounded by the variety of approaches currently used to schedule HVDC facilities in day-ahead and real-time markets.

*MISO could assess the risk of FTR underfunding and potential missed hedging opportunities and evaluate process enhancements to better align FTR auctions with evolving operational practices.* Implementation approach and timing would depend on project characteristics, agreements with neighboring RTOs, regulatory direction, and stakeholder engagement outcomes.

## **RELIABILITY OPERATIONS**

VSC-based HVDC technology<sup>3</sup> can play an important role in enhancing system stability. It can provide fast and precise power flow control, helping to reduce bus phase angle separation during disturbances and supporting voltage in weak grid areas. Additionally, it can contribute to inertia-like responses and oscillation damping.

However, as these systems become more widespread and interact with Inverter-Based Resources (IBRs) and other advanced controls, new converter-driven and resonance stability risks may emerge. The net

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<sup>3</sup> The reliability assessment focuses on the impacts of Voltage Source Converter (VSC)-based HVDC systems. While the background section of this document discusses multiple HVDC technologies, VSC systems are emphasized due to their prominence in current HVDC proposals across MISO's footprint.

stability benefit of HVDC therefore depends on the availability of appropriate technology, proper control tuning, and continuous coordination with real-time operations.

Figure 2 provides a conceptual representation of stability benefits and risks associated with VSC-based HVDC technology.

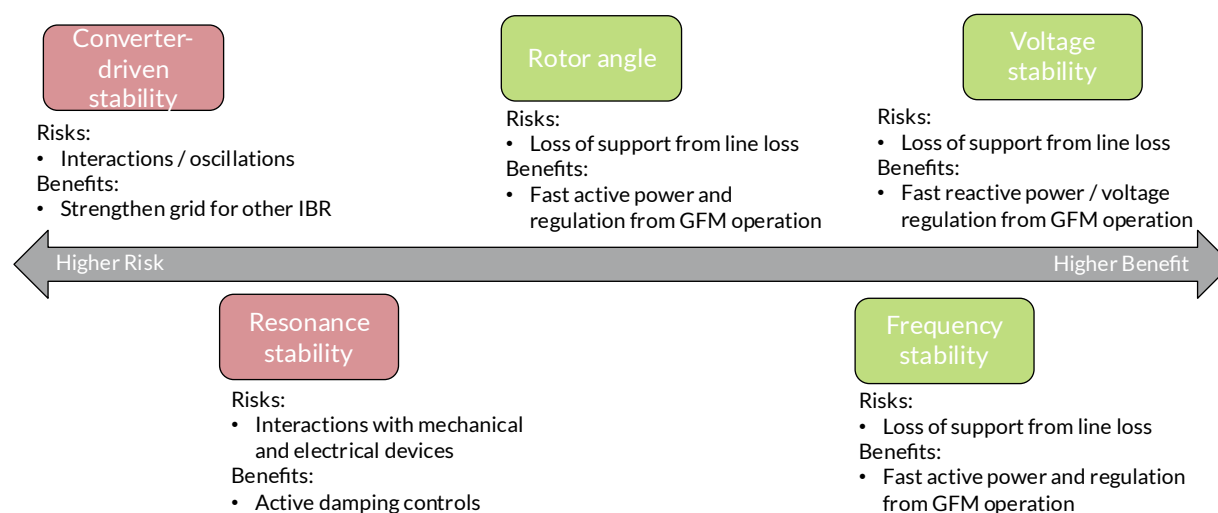


**Figure 2: Conceptual representation of the risks and benefits of VSC-HVDC on various aspects of system stability**

As described in the [Market Impact Assessment](#) section, MISO uses three types of HVDC models, developed on a case-by-case basis, to meet specific operational needs. These models support various real-time analysis functions in the Energy Management System (EMS). The way an HVDC system is modeled directly affects the data that must be delivered via Supervisory Control and Data Acquisition (SCADA). Under current practices, SCADA does not include dedicated DC-side alarms, and many models simplify or omit HVDC controllability and loss characteristics. This limits operator visibility into HVDC interactions with the broader grid. As HVDC penetration increases, the grid will require enhanced representation of HVDC facilities within MISO's EMS, along with other enhancements to improve operator visibility.

Contingencies involving large HVDC lines can create disproportionate impacts due to the sudden and significant loss of power transfer. When a line trips offline, system frequency declines rapidly, with the Rate of Change of Frequency (RoCoF) depending on the outage magnitude and available inertia. In lower-inertia conditions, this can trigger widespread IBR tripping, Underfrequency Load Shedding (UFLS), and immediate activation of operating reserves. The loss of an HVDC line can create large shifts in power flow across tie lines and constrained interfaces, potentially causing thermal overloads and dynamic stability risks. Deliverability of contingency reserves becomes critical, particularly when reserve-sharing arrangements across Balancing Authorities are limited.

The current outage coordination process, outlined in [Business Practice Manual \(BPM\)-008](#), provides a robust framework for planning, analyzing, and managing transmission and generation outages using tools such as the Control Room Operations Window (CROW) and Available Flowgate Capability (AFC) evaluations. However, HVDC systems involve converter stations, DC cables, and reactive support



equipment, each of which may require maintenance or experience partial outages and must be mapped into existing outage categories. Outage coordination should increasingly incorporate stability assessments, as HVDC outages can cause high magnitude, complex impacts beyond thermal constraints.

## RECOMMENDATIONS

Following the reliability impact assessment and gap analysis, MISO has identified potential next steps:

### 1. Contingency management procedures for HVDC facilities

Due to the large size of some of the HVDC facilities being considered in the MISO region, the potential loss of one of these facilities could have significant impacts. The loss could become the Most Severe Single Contingency (MSSC) for the MISO region, increasing contingency reserve requirements, which would have associated cost impacts. *MISO should continue to update the MSSC and contingency reserve requirements as system conditions evolve to ensure reliability. As HVDC penetration increases, MISO should assess the risk of contingency reserve cost increases and evaluate opportunities to mitigate these impacts through reserve sharing agreements or alternative cost allocation processes.*

### 2. HVDC impacts on system stability risk

The sudden loss of a large HVDC facility could affect frequency, voltage, and rotor angle stability. Additionally, like other inverter-based facilities, power electronic controllers on the HVDC facility may contribute to oscillations. *As penetration of HVDC facilities increases, MISO should conduct, or coordinate with other entities to conduct, frequency, voltage, and rotor angle stability risk assessments related to HVDC facility losses, including evaluations of converter-driven stability risks.*

### 3. Outage coordination and operator visibility for HVDC facilities

HVDC facilities currently operating in MISO participate in both outage coordination and real-time operations processes. However, participation could be enhanced in several ways. *As penetration of HVDC facilities increases, MISO should evaluate more granular representation of de-rates during outage coordination processes, enhance the representation of HVDC facilities in the Energy Management System, and consider other improvements to improve operator visibility.*

## RESOURCE ADEQUACY

Several merchant HVDC transmission lines are being proposed for interconnection to the MISO transmission system. MISO has had numerous discussions with stakeholders regarding the increased interregional transfer capability that the new HVDC transmission could provide, and how this capability may contribute to reliability and help relieve pressure on planning requirements. Stakeholders have sought guidance on the treatment and potential accreditation of these HVDC transmission lines within MISO's resource adequacy construct which will help inform future investment decisions.

Through these discussions, MISO has communicated that incorporating HVDC into existing resource adequacy processes, or developing new processes, cannot occur in isolation from a holistic assessment of overall HVDC integration. MISO acknowledges the need for stakeholder confidence prior to advancing HVDC transmission proposals, which is why MISO is providing this framework to guide evaluation of potential changes to the resource adequacy construct.



MISO has considered several mechanisms to incorporate HDVC transmission into the resource adequacy construct, provided here for discussion. Many of the potential solutions could require significant changes to MISO's Loss of Load Expectation (LOLE) modeling, as well as coordination and agreements with neighboring regions.

## RECOMMENDATIONS

MISO is committed to continuing work in this area and offers the following recommendations:

### 1. Resource adequacy treatment of external resources, including those delivered via HVDC

Under the current resource adequacy construct, External Resources can earn accreditation in the Planning Resource Auction (PRA) by demonstrating a firm contractual right to capacity and firm transmission to the MISO border and from the border to an identified MISO sink. These existing mechanisms allow HVDC-enabled external resources to participate directly in the PRA. However, stakeholders have conveyed that this process lacks sufficient clarity.

*MISO should collaborate with stakeholders to clarify how external resources, including those delivered by HVDC-enabled firm transmission, are modeled and participate under MISO's current resource adequacy construct.*

### 2. Accreditation enhancements for external resources

Accreditation of external resources has not yet been aligned with the Direct Loss of Load/Resource Adequacy hours framework that will apply to internal resources beginning in Planning Year 2028/29.

*MISO should evaluate updates to external resource accreditation to improve alignment with the Direct Loss of Load/resource adequacy hours approach.*

### 3. Representation of transmission in resource adequacy risk modeling

MISO's resource adequacy risk model is used to determine the system-wide Planning Reserve Margin Requirements (PRMR), Local Reliability Requirements, and, in the future, the accreditation of resources. Today, this analysis is conducted without transmission modeled (a copper sheet).

*MISO could evaluate approaches to incorporating transmission, including HVDC facilities, into resource adequacy risk modeling.*

## INTERCONNECTION OF MERCHANT INTERREGIONAL (OR INTRA-REGIONAL) HVDC LINES

Merchant interregional HVDC projects are progressing through the MISO MHVDC queue. Realizing the commercial value of these projects depends on securing the appropriate commercial products and approvals, including injection and withdrawal rights, deliverability for capacity and market participation, Transmission Service Request (TSR) transactions, and, where applicable, clearly defined limited-operation conditions to support safe interim use.

Reliable integration of MHVDC projects requires disciplined modeling and coordinated execution across all parties involved, including RTOs/ISOs, interconnection customers, Transmission Owners, and neighboring systems.



## RECOMMENDATIONS

Future work planned for MHVDC through the Interconnection Planning Working Group (IPWG) includes:

- 1. Improvements to the MISO Attachment GGG process**

Stakeholders have requested greater clarity and streamlining of interconnection processes for HVDC facilities. These requests include the use of TSRs via Module B for injection and withdraw rights and the development of preliminary MHVDC study procedures to better service customers prior to the full Attachment GGG studies. *MISO is making Tariff revisions to Attachment GGG, updating the MISO MHVDC interconnection process, and clarifying limited-operation conditions for interim periods on qualified MHVDC projects. MISO will continue engaging with stakeholders on these topics through the IPWG and PAC.*

- 2. HVDC Business Practice Manual**

Stakeholders have requested that MISO develop a dedicated BPM to enhance clarity, efficiency, and alignment with Tariff requirements for the MHVDC interconnection process. *MISO is creating an HVDC BPM that will address MHVDC applications, application modifications and withdrawals, study scope and timelines, study requirements, affected system studies, and pre-TCA considerations.*

## TRANSMISSION EXPANSION PLANNING OF INTRA-REGIONAL HVDC LINES

From a regional planning perspective, MISO applies an “all things considered” strategy when evaluating transmission solutions, including legacy EHV AC (345 kV and 500 kV), 765 kV EHV AC, and HVDC options. MISO analysis shows that HVDC generally offers a lower cost-per-megawatt-mile for line lengths exceeding 400 miles, whereas EHV AC, particularly 765 kV, tends to have the lowest cost-per-megawatt-mile for lines shorter than 250 miles. For line lengths between 250 and 400 miles, HVDC versus EHV AC must be evaluated on a case-by-case basis.

HVDC provides granular flow control that can be advantageous in managing flows on parallel AC lines. Conversely, EHV AC’s natural flow response can be more effective for managing renewable variability and large load fluctuations. These trade-offs are further described in this white paper.

While Line-Commutated Converter (LCC) HVDC lines consume substantial reactive power, newer VSC HVDC lines provide dynamic reactive support, a potential benefit when nearby facilities (e.g., conventional synchronous machines or inverter-based generation resources) are not already available to supply sufficient dynamic reactive power. Therefore, the potential reactive power benefits of VSC HVDC must be evaluated on a case-by-case basis.

In addition, VSC HVDC converters are also grid forming, a potential benefit when nearby facilities (e.g., conventional synchronous machines and grid forming inverter-based generation resources) are not already in place and capable of supplying these grid forming benefits. Therefore, the potential grid-forming benefits of VSC HVDC must also be evaluated on a case-by-case basis.

HVDC may play an important role alongside EHV AC solutions in MISO’s future regional transmission system. However, any HVDC solutions selected through the regional planning process will need to either:

- Employ VSC technology, be dispatchable, and be co-optimized with resource outputs on a five-minute basis through the real-time SCED algorithm; or



- Be configured with controls that emulate an AC line using a proxy impedance not feasible for an AC line of comparable length.

## RECOMMENDATIONS

### 1. Test modeling and performance of PROMOD HVDC simulation capabilities

HVDC may play a role alongside EHV AC solutions in MISO's future regional transmission system. However, any HVDC solutions selected through the regional planning process will need appropriate modeling and control capabilities. *As a medium priority, MISO should test the modeling and performance of the dispatchable and co-optimized HVDC capability of PROMOD to ensure it is an acceptable proxy for the dispatchable HVDC solution to be developed by the market side.*

### 2. Investigate feasibility of AC line emulation controls

Some HVDC facilities can be configured to emulate the behavior of AC transmission facilities. *MISO could further investigate the feasibility of AC line-emulation controls as an option for future regional HVDC lines where AC response is desired, but the line length is too long for an AC line.*





# 1 Background

## STAKEHOLDER ENGAGEMENT

MISO Stakeholders have expressed interest in several focus areas related to HVDC.

For merchant HVDC lines, stakeholders are actively involved in MISO's ongoing work with Attachment GGG updates.

In expansion planning, prior discussions have been conducted with stakeholder involvement. On February 16, 2021, MISO held a stakeholder workshop titled "New Ideas, Approaches, and Technologies to be considered in Planning for a Renewable Heavy Market." MISO and external entities made several presentations on HVDC, including one titled "Market Dispatchable HVDC." MISO has also presented topics on HVDC at the PAC, one at the March 8, 2023, PAC meeting titled "Discussion of 765 kV and HVDC," and a second at the May 2023 PAC, which included an extra day to allow external entities to make HVDC presentations to the PAC.

In markets, MISO and stakeholders have established MISO dashboard issue [MSC-2024-8](#) (Incorporating HVDC in Energy and Ancillary Services Market Operations, as well as Transmission Planning) and [RASC-2024-5](#) (Capacity Accreditation for External Resources facilitated by HVDC Transmission).

Stakeholders were involved in defining the focus areas for this impact assessment document through the [HVDC Assessment Workshop](#) on April 29, 2025 and via [Stakeholder Feedback](#) following that workshop. This assessment addresses stakeholder feedback, outlining the scope of HVDC impacts on MISO planning, operations, and markets and provides recommendations for additional work. A summary of this impact assessment will be presented at the [HVDC Assessment Workshop](#) on December 16, 2025, to be followed with a request for feedback to be submitted by February 2026.

## CONTINUED STAKEHOLDER INPUT IS CRUCIAL

Many ideas in this document reflect input from MISO stakeholders. MISO appreciates stakeholder feedback on this assessment and looks forward to continuing the dialogue with future work.

## HVDC TECHNOLOGY

Multiple HVDC voltage conversion transmission technologies have been considered to operationalize HVDC lines, including motor-generator sets, mercury arc technology, LCC technology, and most recently, voltage source converter (VSC) technology. LCC and VSC technology are solid state technologies and are primarily the technologies being considered for new HVDC transmission lines today. Except for the back-to-back HVDC link installed between Michigan's upper and lower peninsulas, all HVDC lines currently deployed within MISO's footprint are LCC technology. Minnesota Power's HVDC Modernization Project will bring HVDC VSC technology to MISO's footprint by 2030, between a new Nelson Lake substation in North Dakota and a new Saint Louis County Substation in Minnesota.

LCC technology uses thyristors to convert AC waveforms into DC voltages and vice versa. Thyristors are solid state switches that can be switched on by adjusting the firing angle at a precise point in the AC waveform when the device is forward-biased (i.e., when the converter has positive voltage across its





terminals). However, unlike fully controllable switches, thyristors cannot be turned off by control signals. Instead, they rely on the natural behavior of the AC waveform to cease conduction. This process, referred to as natural commutation, occurs automatically every half cycle of the AC voltage. As the AC current reverses direction and reaches zero, the thyristor naturally turns off, allowing the next thyristor in sequence to conduct. This commutation mechanism fundamentally depends on a strong and undistorted AC voltage waveform.

Multiple issues exist with LCC technology. First, LCC converters at both terminals consume a great deal of reactive power to facilitate voltage conversion. Second, unlike synchronous machines, LCC technology cannot form AC voltage waveforms, so historically synchronous machines are required at or beyond each terminal of the HVDC line to form the voltages. Lastly, LCC-based HVDC lines simply transfer power, given that voltages already exist at both line terminals. Because external voltage waveform formation is needed, system strength becomes an issue and LCC HVDC line performance generally requires sufficient levels of system strength at each terminal.

Voltage Source Converter (VSC) technology is a newer technology, one more likely to be used in the future. VSC technology uses solid state switching devices like insulated gate bipolar transistors (IGBTs) to facilitate voltage conversion. These devices can be switched on and off at high frequencies. These switches are controlled using a pulse width modulation (PWM) technique, where pulse timing and width are varied to approximate a desired sinusoidal waveform. This enables the converter to generate a controllable AC voltage and current from a DC source, and vice versa. For this reason, active and reactive power can be controlled independently on the AC side of voltage source converters. Not only does this fully eliminate the reactive power consumption issue associated with LCC technology, but it also allows VSC converters to be used as a source of dynamic reactive power at each AC terminal even when zero active power flow is scheduled on the HVDC line. VSC converters are also grid forming devices: they form AC voltage waveforms just like synchronous machines and grid forming inverters (GFMs) that interconnect renewable and energy storage resources. This benefit is not available from LCC technology. Because of grid forming capabilities, a VSC-based HVDC line can facilitate black starting one asynchronous system from another asynchronous system, unlike an LCC-based HVDC line.

In addition to LCC and VSC types, the HVDC line and converter have different pole and topology configurations, which have varying costs and provide different ways to transmit power. The configurations such as monopole, bipole, and back-to-back arrangements determine how power is transmitted, how redundancy is provided, and how the system behaves during faults or maintenance. Similarly, HVDC topologies such as two-terminal or multi-terminal arrangements determine whether the system operates as a point-to-point or as a more complex DC network with multiple injections and withdrawal points. Additional details about HVDC configuration and topology are provided in the [Technical Appendix](#).

## EXAMPLES OF HVDC TYPE CONFIGURATIONS

The HVDC lines in MISO today are mostly scheduled by the transmission owners, and most were originally put in place as generation lead lines. Additional HVDC configurations in MISO are the back-to-back HVDC station connecting the upper and lower peninsulas of Michigan, and the Manitoba HVDC lines that connect the asynchronous northern Manitoba system to the south. The Manitoba lines are

modeled as an External Asynchronous Resource, allowing for market offer submissions that are co-optimized in SCED and receive dispatch targets. The MISO regionally planned HVDC lines are intra-regional lines (internal to MISO) that would be scheduled by MISO. The scheduling would be via either co-optimizing the line schedules with resource outputs via the Security Constrained Economic Dispatch algorithm that dispatches the real-time market or via special controls to emulate the performance of a proxy AC line with a lower impedance per mile than physically practical. The merchant HVDC lines may be intra-regional or interregional lines that are proposed, paid for and scheduled by a merchant who obtains interconnection service from all interconnected transmission providers which includes funding of any AC network upgrades required to support the operation of the merchant HVDC line within the operating requirements and restrictions of the interconnection agreement. The following figures provide conceptual representations of the current HVDC configuration, MISO's regionally planned and merchant HVDC configurations, owner-scheduled, intra-regional, and merchant interregional HVDC configurations.

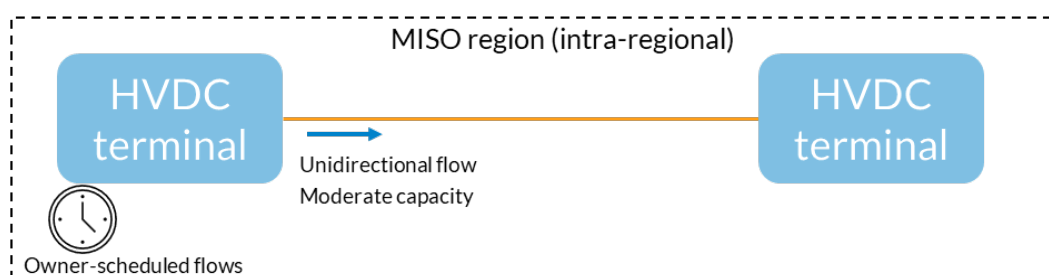


**Figure 3: Current HVDC (originally built as generation lead lines)**

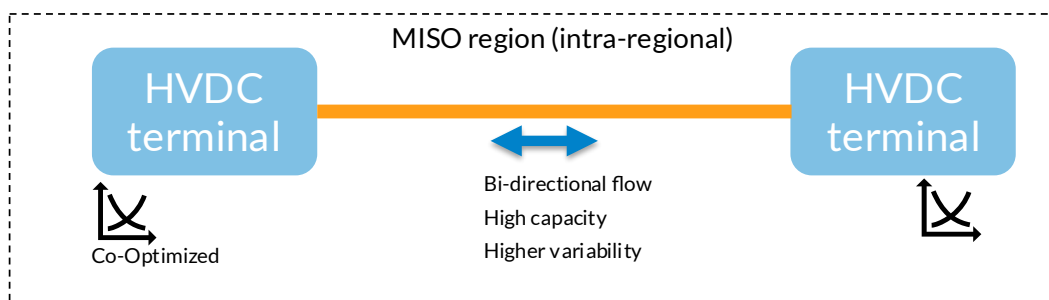


**Figure 4: Regional Planning**

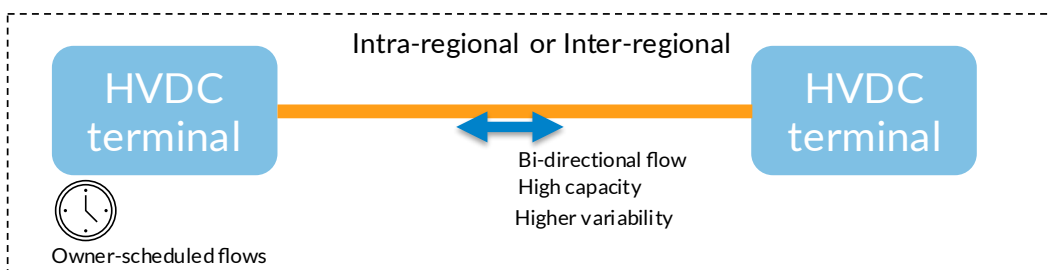


**Figure 5: Merchant HVDC**

## 2 Market Impact Assessment

HVDC technology offers unique controllability and efficiency benefits for both intra-regional transmission within MISO and interregional connections to neighboring systems. While MISO has successfully integrated several HVDC facilities under existing frameworks, the increasing number of proposed projects, particularly merchant-led interregional developments, presents new operational and market design challenges.

### Key Insights

- **Current HVDC models are fragmented and case-specific**, limiting MISO's ability to support scalable, dispatchable HVDC integration across both intra- and inter-regional contexts.
- **Intra-regional HVDC facilities are not fully co-optimized with generation and load**, which can exacerbate AC congestion and reduce market efficiency. Enhanced SCED integration and loss modeling are needed to unlock their full value.
- **Existing interregional coordination mechanisms (M2M, CTS) were designed for AC systems** and do not leverage HVDC's controllability. New coordination levels and participation models are needed to support dynamic interchange and congestion relief.

### Recommendations

- **Interchange and congestion management:** As penetration of HVDC increases, MISO should evaluate approaches to integrate HVDC into interchange and market-to-market congestion management processes and discuss these approaches with our neighbors.
- **Intra-regional HVDC:** As HVDC penetration increases, MISO should evaluate potential approaches from other RTOs to partially integrate intra-regional HVDC into market and operations practices. Additionally, MISO could continue to research open questions related to full integration.
- **HVDC and congestion hedging processes:** MISO could assess the risk of FTR underfunding and possibility of missed hedging opportunities and evaluate potential process enhancements to better align FTR auctions with evolving operational practice.

### CURRENT STATE OF MISO MARKET OPERATIONS

MISO currently supports three HVDC participation models, each developed for specific operational needs and commercial contexts (see Figures 3, 4, and 5 in the Background section for HVDC configuration types). These models reflect not only physical topology but also how HVDC-enabled flows interact with MISO's market systems such as dispatchability, Balancing Authority (BA) relationships, and congestion management. This section summarizes their key characteristics and limitations to assess their suitability for emerging HVDC use cases. While effective within their original scope, these models were developed case-by-case with opportunities remaining to further optimize HVDC, and they do not form a unified framework capable of supporting the diversity of HVDC projects now emerging.



## **GENERATION LEAD LINE MODEL**

This model applies to HVDC lines that are dedicated to delivering energy from a specific generation facility to the MISO grid. These lines are typically intra-regional, operate entirely within MISO's Balancing Authority Area (BAA) and are not used for regional congestion management or broader market transactions. To simplify integration and reflect their dedicated purpose, MISO models HVDC generation lead lines as part of the generator rather than as standalone transmission assets. The HVDC interface is represented using fictitious units: one at the source side, where the generator injects power into the HVDC line, and one at the sink side, where power is delivered to the AC grid. These two units are not electrically connected in the network model. This representation avoids unnecessary AC network complexity and allows the generator to manage HVDC flows directly. It also decouples pricing between terminals, reflecting the fact that the HVDC line bypasses the AC network and does not contribute to congestion between those points.

Because the sink-side unit is where power enters AC grid, it is the point that is visible to MISO's market systems. Ancillary Services such as regulation and contingency reserves are typically offered at the sink-side node. Energy offers may be submitted at both terminals, depending on the modeling configuration. Because the fictitious units are not electrically connected, the HVDC line itself is not directly optimized in SCED. Instead, the generator is responsible for adjusting HVDC flows to match cleared output. Current implementations (e.g., Coal Creek to Dickinson and Square Butte to Arrowhead<sup>4</sup>) operate entirely within the MISO BAA.

## **RELIABILITY ASSET (FIXED/MANUAL SCHEDULE)**

This model applies to intra-regional HVDC lines operated manually under fixed or pre-arranged schedules, without real-time market optimization. The Mackinac HVDC facility illustrates this approach: it is modeled using two fictitious units, one at the source and one at the sink, that are not electrically connected in the network model. HVDC losses are excluded from Locational Marginal Prices (LMPs) and handled outside the dispatch engine. While energy and ancillary service offers may be submitted at both terminals, they do not influence HVDC dispatch, which remains manual. These offers may clear independently based on local conditions but are not co-optimized with HVDC transfers.

## **DYNAMIC TRANSFER (EXTERNAL ASYNCHRONOUS RESOURCE)**

This model enables participation of external resources that are not synchronously connected to MISO's grid. These resources are integrated into MISO's Day-Ahead and Real-Time markets through dynamic scheduling and proxy modeling. Manitoba Hydro is the primary example: its generation fleet is in northern Manitoba and electrically decoupled from the Eastern Interconnection via an internal HVDC system.

MISO models Manitoba as an External Asynchronous Resource (EAR), allowing it to submit market offers that are co-optimized through SCED every five minutes. Once cleared, EARs receive dispatch targets like internal resources. They are modeled at proxy points on the AC side of the HVDC interface, as they are not physically located within MISO's balancing area, and their output is reflected in market settlements. To facilitate interchange, EARs must submit a Fixed Dynamic Interchange Schedule via a dynamic e-Tag.

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<sup>4</sup> Square Butte was originally modeled as a unidirectional generation lead line but now supports both injections and withdrawals.

This tag includes a pre-approved hourly schedule and a dynamic energy profile that reflects expected 5-minute dispatch levels. While the e-Tag itself is not updated sub-hourly, the physical interchange is expected to follow the SCED-cleared dispatch. Deviations are monitored, and the dynamic profile is used to align physical flows with market instructions without requiring continuous tag updates.

This structure supports both import and export transactions, allowing EARs to offer energy (positive or negative) and ancillary services such as Regulation and Contingency Reserves. Importantly, MISO does not calculate sensitivities directly across the HVDC line. Instead, congestion management is handled at the AC-side proxy nodes where the EAR is modeled. This approach is effective because EAR dispatch is not expected to cause congestion on Manitoba's AC system, allowing MISO to manage impacts without modeling the external network in detail.

## **SUMMARY OF CURRENT STATE**

MISO's current HVDC facility models were developed to serve specific operational and commercial needs. As HVDC proposals diversify in design and purpose, participation models will need to accommodate configurations ranging from short back-to-back links to long interregional lines. While the specific instruments and scheduling mechanisms may vary, MISO's approach to market integration: dispatch, loss modeling, and controllability should all align within a consistent optimization framework. To inform potential enhancements to MISO's HVDC integration framework, it is useful to examine how other grid operators around the world have approached HVDC market participation, optimization, and coordination.

## **BEST PRACTICES FROM OTHER MARKETS**

The way HVDC facilities are integrated into markets depends less on their physical configuration and more on how they are embedded within operational and institutional frameworks. North American examples provide the most directly applicable insights for MISO, as these markets share similar nodal pricing structures, real-time dispatch mechanisms, seams coordination challenges and common regulatory framework. In contrast, international examples reflect different operational and market structures, offering alternative approaches worth considering.

## **NORTH AMERICAN RTO MARKETS**

North American RTOs have adopted varied approaches to HVDC integration, largely shaped by balancing area needs and market design. Intra-BA facilities like CAISO's Trans Bay Cable are integrated into 5-minute SCED but it does not participate directly in Ancillary Services market. In contrast, inter-BA HVDC facilities especially those connecting synchronized systems like PJM and NYISO typically operate under fixed or hourly schedules with limited market optimization. These merchant lines (e.g., Neptune, Cross Sound Cable) generally serve load pockets and are excluded from real-time congestion management because their flows are not co-optimized through joint dispatch.

Asynchronous interties offer greater flexibility. Because asynchronous HVDC decouples system frequency, one RTO can dispatch the resource independently. For example, MISO's integration of Manitoba Hydro via the EAR model allows independent dispatch across BA boundaries enabling participation in 5-minute SCED and ancillary services. However, broader integration challenges persist.



No U.S. RTO currently models HVDC losses in real-time LMPs, and proposed congestion hedging products remain limited to intra-RTO footprints. While some RTOs (e.g., SPP) are exploring option-based Transmission Congestion Rights (TCRs) for controllable transmission, cross-market hedging remains unsupported due to incompatible settlement systems.

## **GLOBAL HVDC MARKET INTEGRATION**

HVDC infrastructure is widespread globally, with significant deployments in Asia, South America, and other regions. However, most of these systems operate under centralized planning models or utility-controlled dispatch that offer limited insights for market-based RTO environments. Two market-based systems, Australia's National Electricity Market (AEMO) and Europe's coordinated market coupling framework, provide useful comparisons. Both demonstrate more advanced sub-hourly optimization approaches than most North American inter-BA implementations, though under fundamentally different institutional and market structures than US nodal markets.

More details about the North American RTO HVDC market integration and global HVDC integration are included in the Appendix, section on “Comparative Analysis of HVDC Market Integration.”

## **IMPLICATIONS FOR MISO**

For MISO, the examples above highlight a range of design choices and modeling practices that can inform how intra-regional HVDC might be integrated into MISO's market systems. North American cases reveal persistent barriers to synchronized inter-BA HVDC dispatch such as differences in market rules, settlement systems, and operational coordination. A unified optimization framework for HVDC in MISO will require not only improved modeling but also scalable coordination mechanisms that reflect the diversity of project types and dispatch authorities. These insights point to the need for solutions that align with MISO's specific operational context.

## **INTRA-REGIONAL HVDC OPTIMIZATION**

Intra-regional HVDC facilities within MISO's footprint present different market integration considerations than interregional facilities that span RTO boundaries. While interregional coordination must address seams issues and multi-party settlement, intra-regional HVDC can potentially leverage MISO's existing dispatch framework for economic optimization. This section outlines the technical considerations and modeling refinements that would be required to support such integration within MISO's economic dispatch process.

## **DISPATCH INTEGRATION IN SCED**

Integrating HVDC into MISO's SCED framework would allow controllable HVDC flows to be co-optimized with generation and load, enabling the system to dynamically respond to congestion, price signals, and system conditions. In this model, HVDC line flows become dispatch variables, with offers and bids submitted at both terminals. This allows the HVDC line dispatch to relieve AC line transmission constraints, support economic transfers, and enhance system flexibility. However, modeling HVDC as a controllable transmission element introduces complexity, as it affects power balance at both terminals and interacts with AC constraints.





MISO's preliminary SCED formulations have shown promise under positive pricing but revealed challenges under negative prices, including circular flows and loss-maximizing dispatch. These issues stem from simplified, linear loss approximations which do not accurately reflect the relationship between losses and flow magnitude or direction. Additional challenges include oscillatory dispatch behavior, inaccurate loss modeling for large HVDC transfers, and potential stability concerns in weak AC areas. Addressing these issues requires enhancements such as piecewise or hybrid loss models, integer variables for flow direction, and angle difference constraints to prevent circular flows.

Other RTOs have implemented practical solutions that offer near-term guidance. As a transmission asset under CAISO operational control, the Trans Bay Cable is integrated into the five-minute dispatch to manage congestion. It does not actively bid into ancillary service markets. HVDC losses are not modeled explicitly within the market optimization. NYISO, meanwhile, uses a proxy bus model and a two-part settlement structure that reflects both day-ahead schedules and real-time deviations. This approach enables economic optimization of HVDC flows while maintaining operational control and ensuring losses are reflected in pricing and settlement. These examples demonstrate that partial integration is feasible and can inform MISO's path forward.

### **ANCILLARY SERVICE PARTICIPATION**

Dispatchable HVDC facilities could provide ancillary services to support grid reliability and operational flexibility. Generation resources at the sending terminal could offer regulation and operating reserves, while load resources at the receiving terminal could participate in demand response programs. The controllability of HVDC enables ancillary service delivery across internal transmission constraints that might otherwise limit resource participation.

### **CONGESTION HEDGING FOR INTRA-REGIONAL HVDC**

As dispatchable HVDC becomes integrated into SCED, MISO will need to evaluate how congestion revenues are allocated and whether existing Financial Transmission Rights (FTRs) provide adequate hedging coverage. Current FTR frameworks were designed for AC transmission and do not account for the directional and controllable nature of HVDC. Other RTOs offer contrasting models: NYISO and CAISO generally exclude HVDC from their congestion rights markets to preserve dispatch flexibility. SPP has developed an 'option-style' settlement proposal for DC ties connecting the Eastern and Western interconnections. Under this framework, congestion rights across the back-to-back facilities would function as options rather than obligations, protecting holders from counter-flow payments. These examples highlight that the appropriate hedging structure depends on multiple factors including the facility's dispatchability, market integration, and role in congestion management. MISO may need to evaluate flexible approaches such as segmented settlement or optionality-based rights to determine whether they align with its operational and market framework.

### **TECHNICAL CHALLENGES**

Dispatchable HVDC integration into SCED presents several technical challenges that require careful modeling. These include circular flow behavior, loss modeling inaccuracies, and interactions with AC system constraints.



**Circular flows** can arise when HVDC interacts with AC congestion or negative pricing in ways that create looped transfers. These flows may appear economically rational in the optimization but are physically inefficient or infeasible. They can occur under both fixed and dispatchable HVDC schedules and are exacerbated when the optimization inadvertently maximizes losses under negative LMPs. Even under positive prices, circular flows may emerge when HVDC is used to relieve AC congestion, especially in systems with strong parallel AC paths.

**Loss modeling** is another important consideration. MISO's current SCED uses linear loss sensitivity factors, which are generally sufficient for small AC redispatch but become inaccurate with large HVDC transfers. Piecewise linear (PWL) or hybrid loss models offer better accuracy but introduce complexity, especially under negative prices, where the optimization may favor high-loss segments unless constrained. Without proper modeling, dispatch outcomes may become oscillatory or non-physical.

**System stability** issues may also arise. HVDC facilities, especially based on voltage source converter technology, have the technical capability to support voltage and frequency stability. However, HVDC dispatch can interact with AC system in ways that might increase overall system stress and create stability issues. The HVDC converter interactions are even more prominent in weak AC areas, requiring further evaluation outside the SCED framework.

MISO, in collaboration with NLR, is actively researching modeling enhancements to support dispatchable HVDC, including improved loss modeling, circular flow mitigation, and flow direction optimization. While these challenges are real, other RTOs have already implemented practical solutions that offer near-term guidance. As discussed earlier, CAISO and NYISO provide contrasting but instructive models for integrating HVDC into real-time dispatch and settlement. These examples show that partial integration is both feasible and effective. MISO may evaluate these potential approaches to partially integrate intra-regional HVDC into market and operational practices. In parallel, ongoing research could address open questions related to full integration. For additional modeling details and mathematical formulations related to intra-regional HVDC integration, see the Appendix section titled "Technical Formulations for Intra-Regional HVDC."

## INTERREGIONAL HVDC COORDINATION AND MARKET PARTICIPATION

Existing interregional coordination mechanisms were designed for AC systems, where flows follow physical laws and cannot be directly controlled. HVDC, by contrast, offers controllability that introduces new flexibility for both scheduling and congestion management. This contrast highlights the need to reassess current frameworks and identify enhancements to better align with HVDC capabilities.

### EXISTING INTERREGIONAL COORDINATION PROCESSES

MISO coordinates interregional flows using four legacy mechanisms: Market-to-Market (M2M), Coordinated Transaction Scheduling (CTS), Transmission Loading Relief (TLR), and Phase Angle Regulators (PARs). These were designed for conventional AC systems with fixed, scheduled flows. While these mechanisms govern how flows are economically or operationally coordinated between RTOs, all resulting interchange - whether from CTS, bilateral agreements, or other sources - must be submitted through the NERC-administered e-Tag system. Coordination practices vary by neighbor: MISO uses market-based coordination with PJM and SPP; bilateral scheduling with TVA and AECI; and asynchronous





coordination with Manitoba Hydro through the EAR model. Each mechanism reflects the operational and market arrangements in place with the respective entity.

### ***NERC-ADMINISTERED E-TAG SYSTEM***

Although not a coordination mechanism itself, the e-Tag system is a primary compliance tool that documents and implements scheduled transactions across balancing areas. Regardless of how interchange is determined such transactions must be submitted and approved via e-Tags. While essential for reliability and compliance, e-Tags are not updated in real time and do not support sub-hourly adjustments, limiting their ability to reflect HVDC's fast controllability.

### ***TRANSMISSION LOADING RELIEF (TLR)***

TLR is a reliability-based curtailment procedure used when transmission constraints threaten to exceed system limits. Administered under NERC standards, TLR identifies and curtails scheduled transactions that contribute to constrained flowgates based on their calculated impact and firmness. It is a reactive tool, invoked when other coordination mechanisms are unavailable or insufficient. TLR does not consider economic efficiency, lacks financial settlement, and operates independently of market dispatch. HVDC schedules submitted via e-Tags may be curtailed under TLR, but the process does not leverage HVDC's controllability to manage congestion proactively.

### ***PHASE ANGLE REGULATOR (PAR) COORDINATION***

PARs are AC flow control devices used to manage loop flows across seams, such as those between MISO and Ontario's Independent Electricity System Operator (IESO). They adjust the phase angle of voltage to steer power flows across parallel AC paths. PAR coordination is governed by bilateral protocols and focuses on meeting agreed flow targets through tap adjustments. While PARs offer controllability, they operate within a reliability framework and are not integrated into market-based redispatch or interchange optimization. HVDC, by contrast, provides direct point-to-point control and could complement PARs if coordinated effectively. However, current frameworks do not account for interactions between HVDC injections and AC flow control devices like PARs.

### ***COORDINATED TRANSACTION SCHEDULING (CTS)***

CTS is a forward-looking interchange scheduling mechanism jointly implemented by MISO and PJM. It allows market participants to submit interface bids based on forecasted price difference between proxy buses in each RTO. These bids are evaluated and cleared every 15 minutes, resulting in scheduled interchange that reflects expected economic arbitrage opportunities. CTS was designed to improve the efficiency of scheduled interchange by aligning it more closely with real-time price signals, while preserving the independence of each RTO's dispatch.

Despite its market-based design, CTS is limited in its responsiveness and scope. Bids must be submitted at least 75 minutes in advance, and once cleared, the resulting schedules are fixed for the delivery interval. This lag between bid submission and flow execution reduces the ability to respond to real-time system conditions, especially under volatile or uncertain conditions. Moreover, CTS does not coordinate with M2M redispatch. If CTS-induced flows contribute to congestion, the resulting impacts are managed reactively through M2M, not through adjustment of CTS schedules. HVDC facilities, which can adjust



flows dynamically, are not integrated into the CTS framework and do not participate in the bid-clearing process. While HVDC injections may influence LMPs at proxy buses, CTS does not explicitly model or leverage HVDC controllability.

### **MARKET-TO-MARKET (M2M) FLOWGATE COORDINATION**

M2M coordination is the primary mechanism for managing real-time congestion across market-based seams, such as those between MISO and PJM or SPP. It was designed to replace reliability-based curtailment with economic redispatch, allowing each RTO to relieve congestion on jointly monitored flowgates using its own internal generation. When a flowgate becomes constrained, the monitoring RTO sends its shadow price to the non-monitoring RTO. If the non-monitoring RTO can provide relief more economically, it redispatches generation to reduce its contribution to the constraint. This process runs every five minutes and is aligned with each RTO's SCED cycle. A summary table of coordination mechanisms with neighboring entities is provided in the Appendix under "Coordination Mechanisms by Neighboring Entities".

However, M2M was built around the assumption of fixed net interchange and does not include mechanisms to coordinate controllable transmission assets like HVDC. HVDC flows are treated as part of the fixed interchange baseline and are not redispatched through the M2M process. While HVDC can materially affect flowgate congestion, the current framework lacks the ability to request or respond to HVDC adjustments. Shadow price exchange provides a signal of congestion cost but does not convey HVDC availability, ramp capability, or economic value. As a result, HVDC flexibility remains untapped in M2M coordination, limiting its potential to support congestion relief across seams.

### **LIMITATIONS OF CURRENT COORDINATION MECHANISMS FOR HVDC**

Despite the range of mechanisms available for interregional coordination several structural and operational gaps remain. These gaps are not specific to HVDC but reflect broader limitations in how congestion and interchange are managed across seams.

**Timing misalignment:** MISO's coordination tools operate on different timescales. M2M runs every 5 minutes in sync with SCED, while CTS clears every 15 minutes but requires bids 75 minutes ahead. TLR is purely reactive, triggered only when constraints bind. These mismatched timelines can lead to inefficient flows, especially when forecasts diverge from real-time conditions. HVDC's fast controllability could improve outcomes but leveraging it requires more frequent or forward-looking coordination balanced against added data and computational demands.

**Reactive and delayed congestion management:** Most existing tools are inherently reactive. TLR is triggered by reliability violations, and M2M redispatch begins only after a constraint is binding and coordination thresholds are met. Even then, the Independent Market Monitor has noted that administrative delays in M2M activation can reduce the timeliness and effectiveness of relief<sup>5</sup>. These lags can result in higher congestion costs and missed opportunities for early intervention, especially problematic when HVDC could have provided fast, targeted relief had it been integrated into the process.

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<sup>5</sup> [2023 State Of The Market Report \(https://www.potomaceconomics.com/wp-content/uploads/2024/08/2023-MISO-SOM\\_Appendix\\_Final.pdf\)](https://www.potomaceconomics.com/wp-content/uploads/2024/08/2023-MISO-SOM_Appendix_Final.pdf)



**Incomplete information exchange** Coordination frameworks must balance HVDC dispatch flexibility with the need to manage its impact on AC network constraints in both systems. The right approach depends on the HVDC project's purpose, the institutional relationship between RTOs, available infrastructure, and stakeholder preferences. Effective coordination requires richer information exchange, such as shadow prices, LMPs at both terminals, ATC, ramp rates, and real-time relief potential. The level of detail needed varies by model: unilateral dispatch may need less, while bilateral optimization requires more. Tailoring information exchange to the coordination model is crucial to leveraging HVDC controllability.

**Structural misalignment with HVDC capabilities:** Current mechanisms assume that transmission is either passive (AC) or scheduled in advance (interchange). Neither M2M nor CTS is designed to coordinate dynamically dispatchable transmission assets. For example, M2M treats HVDC flows as fixed contributions to market flows, excluding them from redispatch logic. CTS assumes participant-driven scheduling, not operator-controlled dispatch. TLR and PAR coordination are reliability tools with no economic optimization. These limitations become increasingly problematic as neighboring systems integrate higher levels of renewable generation, creating more volatile dispatch patterns and rapid changes in interchange needs that current coordination frameworks cannot efficiently manage.

## INTERREGIONAL COORDINATION RESEARCH WITH NLR

Recent research by NLR, academic institutions, and industry collaborations has explored ways to improve interregional coordination in systems with diverse resources and controllable transmission. These efforts offer conceptual frameworks and practical tools for evaluating coordination alternatives that align with evolving system needs, particularly in the context of HVDC.

### OPERATIONAL MECHANISM: REAL-TIME AND FORWARD PROCESS INTEGRATION

A key focus of this work is enhancing coordination between RTOs where controllable transmission, such as HVDC, is involved. While nodal markets have advanced internal optimization through tools like Security Constrained Unit Commitment (SCUC) and SCED, coordination across seams remains fragmented. Responsibilities for power balance, reserves, and congestion management are distributed across entities, which can limit overall system efficiency. MISO is continuing its collaboration with NLR to identify scalable strategies for HVDC coordination that reflect these operational realities.

NLR's research categorizes real-time coordination methods into several tiers of complexity and responsiveness. These include basic shadow price exchange (RT1), price curve sharing (RT2), marginal resource representations (RT3), and relief cost curve exchange (RT4). Each approach offers trade-offs in terms of communication overhead, responsiveness, and implementation complexity. HVDC adds further flexibility but also requires mechanisms to determine flow direction, ramping, and congestion impacts in near real-time. Coordination models must account for these dynamics without introducing instability or excessive operational burden.

### MULTI-ENTITY COORDINATION FRAMEWORKS

To support this, NLR has developed a framework to assess how RTOs manage four key constraints:



*Power Balance:* Each RTO ensures that generation matches load plus losses and interchange. Coordination at this level involves aligning net interchange schedules or enabling dynamic adjustments through mechanisms like HVDC dispatch.

*Transmission Constraints (Energy Flow):* RTOs manage congestion on internal flowgates using SCED. Coordination here involves sharing shadow prices or redispatch responsibilities for jointly monitored flowgates, as in M2M processes.

*Reserve Requirements:* RTOs procure and deploy reserves to meet reliability standards. Coordinating reserve procurement or sharing reserve capacity across seams is rare but could improve system flexibility.

*Transmission Constraints (Energy + Reserve Flow):* These constraints ensure that the system can deliver reserves under post-contingency conditions. Coordination at this level is complex and typically not implemented across RTOs today.

Depending on their operational goals, RTOs can coordinate on any combination of system constraints. While full coordination across all four categories may be impractical, targeted enhancements like incorporating HVDC into real-time congestion management or enabling forward interchange coordination can deliver meaningful benefits. MISO will continue working with NLR to evaluate scalable coordination methods that better leverage HVDC controllability without requiring full integration.

## **IMPLICATIONS FOR INTERREGIONAL HVDC OPTIMIZATION**

Interregional HVDC can both relieve AC congestion and dynamically optimize net interchange between RTOs, but current coordination frameworks, designed for fixed interchange and generation redispatch limit its potential. Real-time HVDC dispatch remains constrained by institutional boundaries, incomplete data exchange, and lack of protocols for dynamic control. Forward coordination could improve efficiency, especially under high renewable conditions, while real-time integration into SCED could enable one RTO to dispatch HVDC for both internal and interregional relief. However, this raises questions around dispatch authority, settlements, and system impacts. Flexible, scalable coordination models could deliver significant benefits without requiring full joint optimization.

## **POTENTIAL MISO ENHANCEMENTS FOR INTERREGIONAL HVDC COORDINATION**

Merchant HVDC developers are proposing interregional transmission facilities that recover costs through capacity sales rather than regulated rates. Unlike utility-owned transmission integrated into the RTO tariff, merchant HVDC operators retain commercial control over their facilities while selling transmission capacity to multiple independent participants. This structure requires MISO to coordinate with the HVDC operator on physical dispatch while also managing energy transactions from multiple resources using the line's capacity. The HVDC line's capabilities can only be fully utilized if the external resources enabled by it are able to participate in a manner that supports MISO's market efficiency and grid reliability. This type of dual coordination is not supported by existing frameworks.

## **CANDIDATE COORDINATION APPROACHES FOR MERCHANT HVDC**

While earlier sections have outlined the limitations of existing coordination mechanisms, merchant HVDC projects introduce additional complexity that may require new or enhanced approaches. Table 1



compares three candidate coordination models, illustrating how each differs in terms of dispatch authority, interchange optimization, congestion management, and information exchange. This comparison helps clarify the trade-offs between implementation complexity and operational flexibility.

| Coordination Approach                          | HVDC Role                                    | Interchange Optimization        | Congestion Management        | Information Exchange                                                |
|------------------------------------------------|----------------------------------------------|---------------------------------|------------------------------|---------------------------------------------------------------------|
| <b>Level 0: Merchant Control</b>               | Fixed parameter (merchant sets schedule)     | No                              | Generation redispatch only   | Shadow prices + relief requests                                     |
| <b>Level 1: HVDC for M2M Congestion Relief</b> | Provides M2M relief within fixed interchange | No (fixed net interchange)      | HVDC + generation redispatch | Shadow prices + relief requests                                     |
| <b>Level 2: Interchange Optimization</b>       | Economic dispatch + relief capability        | Yes (15-min ahead or real-time) | HVDC + generation redispatch | Shadow prices + forecasted or real-time price/quantity coordination |

**Table 1 Comparison of Candidate Coordination Approaches for Merchant HVDC**

#### **Level 0: Merchant Control (Status quo)**

The HVDC owner independently schedules flows, with no RTO dispatch authority. Flows are treated as fixed interchange, and coordination occurs through existing M2M processes, which do not adjust HVDC flows. When the HVDC flows contribute to flowgate congestion, both RTOs are limited to reliability-based curtailment. This approach is similar to current M2M framework and simple to implement but does not leverage HVDC's controllability.

#### **Level 1: HVDC for M2M Congestion Relief**

One RTO dispatches HVDC to relieve M2M congestion while maintaining fixed net interchange. The neighboring RTO signals congestion via shadow prices but cannot directly request HVDC adjustments. Research by MISO and NLR demonstrates that a single RTO controlling HVDC dispatch can economically provide M2M relief to neighboring RTOs through enhanced information exchange, including HVDC availability and relief capability, but can operate within an enhanced M2M framework.

#### **Level 2: Interchange Optimization**

One or both RTOs dynamically dispatch HVDC to optimize interchange and manage congestion. Schedules adjust based on real-time or forecasted prices, affecting power balance and transmission constraints in both systems. This model offers the most flexibility but requires new protocols for bilateral scheduling, real-time coordination, settlements, and M2M impact management.

### **EXTERNAL HVDC-ENABLED RESOURCE PARTICIPATION OPTIONS**

Merchant interregional HVDC creates participation challenges distinct from existing frameworks. When multiple independent resources seek to use capacity owned by a separate transmission provider, questions arise about how resources submit offers, how capacity is allocated, and how schedules are



coordinated across RTO boundaries. Three potential participation approaches could be evaluated, each with different trade-offs:

***EAR Model Extension*** would adapt MISO's current single-entity dispatch model to support multiple participants, requiring mechanisms for offer aggregation, flow management, and settlement coordination.

***Pseudo-tie Enhancements*** would treat HVDC-enabled resources as internal, but would need to address capacity sharing, M2M impacts, and the distinction between resource and transmission ownership.

***Enhanced Dynamic Transfer*** is a conceptual approach that would separate commercial transmission rights from physical operation: the HVDC operator sells capacity to multiple participants who submit offers at an interface node, while retaining operational control. This approach raises design questions around dispatch intervals, data exchange, and settlement structures but offers a scalable path for merchant HVDC integration.

## IMPLEMENTATION CONSIDERATION

The appropriate participation model for merchant HVDC will depend on project-specific factors such as physical configuration, commercial structure, developer preferences, coordination level (e.g., merchant control, M2M relief, or interchange optimization), and agreements with neighboring RTOs. Each model raises design questions around loss allocation, ancillary service coordination, and congestion hedging, requiring collaborative development with stakeholders. While HVDC configurations will vary - from short back-to-back links to long-haul, multi-zone lines - a unified participation model is unlikely. However, consistent treatment in market optimization is achievable through standardized approaches to loss modeling, circular flow mitigation, and financially neutral settlement.

For intra-regional HVDC, enhanced SCED modeling can support economic dispatch; for interregional projects, scalable coordination options can align with different dispatch authorities without requiring full joint optimization. The Enhanced Dynamic Transfer model offers a promising path by separating commercial participation from physical operation. Continued work with NLR, developers, and neighboring RTOs will be essential to refine coordination protocols, ensure transparent loss treatment, and develop hedging mechanisms that reflect HVDC's controllability.





## 3 Reliability Operations Impact Assessment

The reliability impact assessment of HVDC systems is organized into four key areas: i) Stability Impact, ii) Operational Modeling, Monitoring, and Control, iii) Contingency Impact, and iv) Reliability Coordination. The Stability Impact assessment evaluates how HVDC influences rotor angle, voltage, frequency, and converter-driven stability, drawing from extensive literature reviews and Transient Security Assessment Tool (TSAT) simulation results. Operational Modeling, Monitoring, and Control explores how Energy Management System (EMS), Supervisory Control and Data Acquisition (SCADA), and network models can be enhanced to accurately represent HVDC behavior, while also assessing the role of advanced tools such as Phasor Measurement Units (PMUs) and wide-area control systems. The Contingency Impact assessment explains system performance under HVDC outage scenarios. Finally, Reliability Coordination reviews the existing outage coordination framework and potential improvements needed to ensure reliable HVDC integration. Topics related to congestion management and market coordination are covered in the Market Operations section and are referenced here for completeness. While a broader discussion of HVDC technologies is provided in the [Background section of this document](#), this reliability impact assessment focuses primarily on Voltage Source Converter (VSC) systems as most proposed HVDC projects within MISO's footprint utilize VSC-based technology.

### Key Insights

- Due to the large size of some HVDC facilities being considered in the MISO region, the loss of one of these facilities could become the MSSC, thereby increasing contingency reserve requirements and resulting in additional cost impacts.
- HVDC facilities can have impacts on frequency, voltage, and rotor angle stability, and like inverter-based resources, their power electronic controllers may contribute to oscillations.
- HVDC facilities currently operating in MISO participate in both outage coordination and real-time operations processes. However, participation could be enhanced in a variety of ways.

### Recommendations

- **Contingency management procedures for HVDC facilities:** MISO should continue to update the MSSC and contingency reserve requirements as system conditions evolve to ensure reliability. As HVDC penetration increases, MISO should assess the risk of contingency reserve cost increases and evaluate opportunities to mitigate these increases through reserve sharing agreements or alternative cost allocation processes.
- **HVDC impacts on system stability risk:** As penetration of HVDC facilities increases, MISO should conduct, or coordinate with other entities to conduct frequency, voltage, and rotor angle stability risk assessments related to the loss of the HVDC facility as well as assess converter-driven stability risks.
- **Outage coordination and operator visibility for HVDC facilities:** As penetration of HVDC facilities increases, MISO should evaluate more granular representation of de-rates during outage coordination processes, enhanced representation of HVDC facilities in the energy management system and consider other enhancements to improve operator visibility.

## HVDC STABILITY IMPACT ASSESSMENT

HVDC systems, particularly those based on VSC technology, have implications across most categories of the IEEE stability taxonomy.<sup>6</sup> A qualitative review conducted by dynamics studies subject matter experts, supported by prior MISO work and findings from other ISOs/RTOs, identified both potential benefits and risks.

The MISO Renewable Integration Impact Assessment (RIIA) noted that VSC-HVDC lines enhance capabilities for power flow control, reactive power and voltage support, dynamic stability, and synthetic inertia.<sup>7</sup> The RIIA study introduces HVDC as a dynamic stability solution starting at the 30% renewable energy milestone, with significant HVDC stability solutions introduced at the 40% milestone. Figure 6 shows the level of HVDC solutions, relative to other solutions, deployed in the RIIA study to resolve stability constraints introduced by increasing levels of renewable energy.

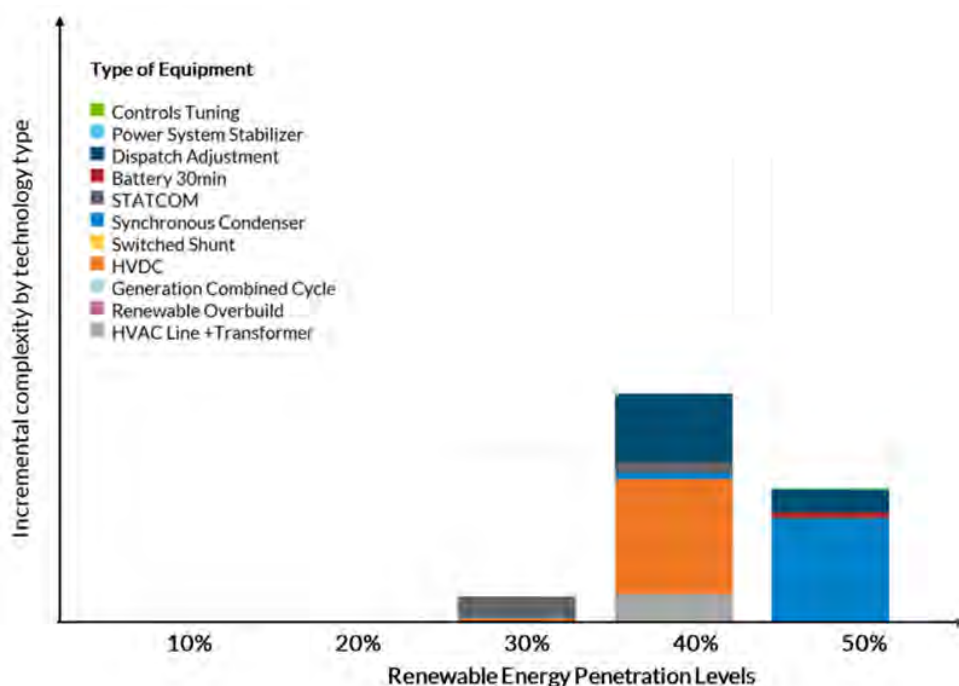


Figure. 6: Dynamic stability solutions -incremental complexity by technology for each renewable penetration milestone (reproduction of RIIA Figure UC-12)

The RIIA study deployed VSC-HVDC as a solution based on recognized stability benefits that include

- **Fast dynamic response:** Independent control of active and reactive power enables P-Q modulation within 10–50 milliseconds for voltage and frequency support
- **Four-quadrant operation:** Bidirectional transfer of real and reactive power
- **STATCOM functionality:** Reactive power support without active power transfer

<sup>6</sup> N. Hatziargyriou et al., "Definition and Classification of Power System Stability – Revisited & Extended," in *IEEE [Institute of Electrical and Electronics Engineers, Inc.] Transactions on Power Systems*, vol. 36, no. 4, pp. 3271-3281, July 2021

<sup>7</sup> MISO, Renewable Integration Impact Assessment. <https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf>



- **Operation in weak systems:** Suitable for operation in grids with low Short Circuit Ratio (SCR)
- **Fault ride-through:** Maintains oscillation damping during grid disturbances
- **Grid-forming capability:** Functions as a voltage source, enabling system restoration and support
- **Grid strengthening:** Increases effective SCR at the point of interconnection, similar to grid-forming inverters
- **Active oscillation damping:** Supports system stability through controller-based damping

However, these benefits are highly dependent on control system design, grid strength, and technology. Poorly tuned or uncoordinated HVDC systems may introduce adverse control interactions and degrade overall system stability. Converter driven stability, or the potential for HVDC to interact with other inverter-based resources, is potentially the greatest current risk of HVDC. Certain types of resonant stability such as sub-synchronous control torsional interactions (SSCTI) were observed in early HVDC installations, posing reliability challenges. The following subsections detail the potential positive and negative operational reliability impacts of HVDC across these categories. Figure 7 provides a more nuanced view of the benefits and risks associated with HVDC.

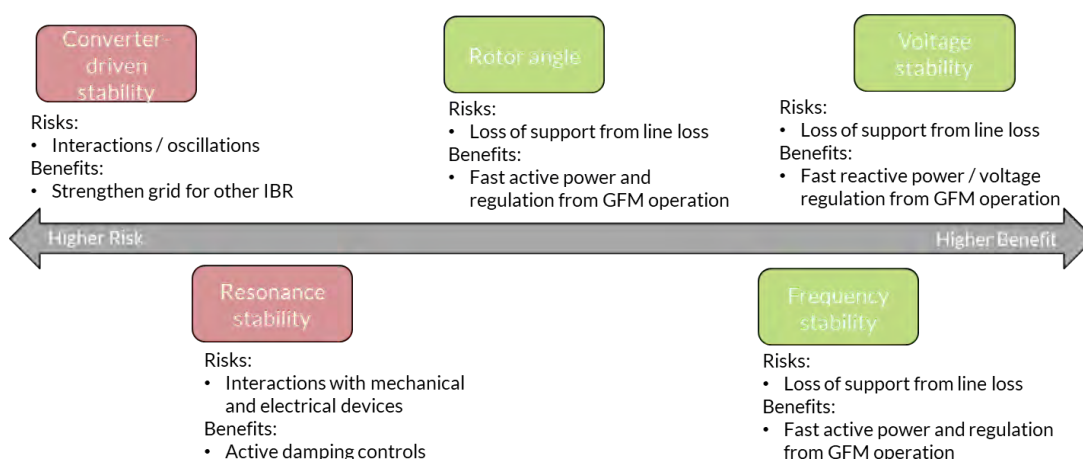


Figure 7: Conceptual risks and benefits of VSC-HVDC lines and stability

## ANGULAR STABILITY SUPPORT

HVDC systems enhance angular stability by decoupling interconnected AC areas, allowing power transfer to remain stable even during large post-fault swings that could destabilize an AC intertie. This electrical separation prevents disturbances in one region from driving oscillations in another. Additionally, HVDC controls can rapidly modulate real power during and after faults, limiting rotor-angle excursions and improving the overall post-fault network stress. The [technical appendix](#) illustrates, using a simplified 176-bus model of Western Electricity Coordinating Council (WECC), how a fast HVDC power transfer can reduce the relative phase-angle differences and lower overall network stress.<sup>8</sup>

<sup>8</sup> S. M. Rovnyak, D. W. Longbottom, D. C. Vasquez, and M. N. Nilchi, "Response-based event detection for one-shot wide-area stability controls," in *Monitoring and Control using Synchrophasors in Power Systems with Renewables*, ser. Books, pp. 177–200, June 29, 2020, [https://doi.org/10.1049/pbpo121e\\_ch8](https://doi.org/10.1049/pbpo121e_ch8)

## VOLTAGE STABILITY SUPPORT

For voltage stability benefits, VSC-based HVDC can almost instantaneously inject or absorb reactive power independent of active power, allowing STATCOM operation. VSC terminals can be designed with full reactive power capabilities. As highlighted in the [technical appendix](#), these benefits have been demonstrated in international grids over the past decade.

The instantaneous reactive power response can be illustrated in a simple test system, such as one described by Figure 8 with a 400 MW VSC-based HVDC link. A representative simulation involves playing back lower voltage steps at the inverter-side Point of Interconnection (POI) bus i.e., bus 4.

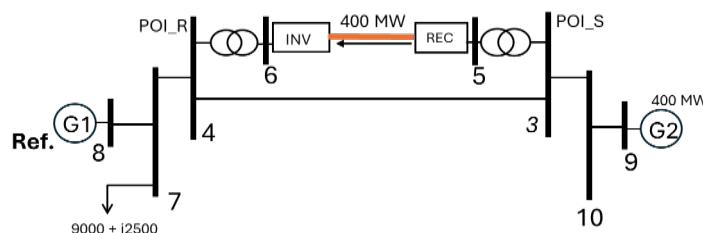


Figure 8: HVDC test system

Two step-reductions in the POI bus voltage are introduced – the first at 2 seconds, and the second at 6 seconds as shown in Figure 9. The V-Q dynamics demonstrate that the inverter’s reactive power shifts from an initial state of absorption (negative Vars) to injection (positive Vars). At 2 seconds, the reactive power injection is increased by 109.1% relative to its pre-disturbance value.

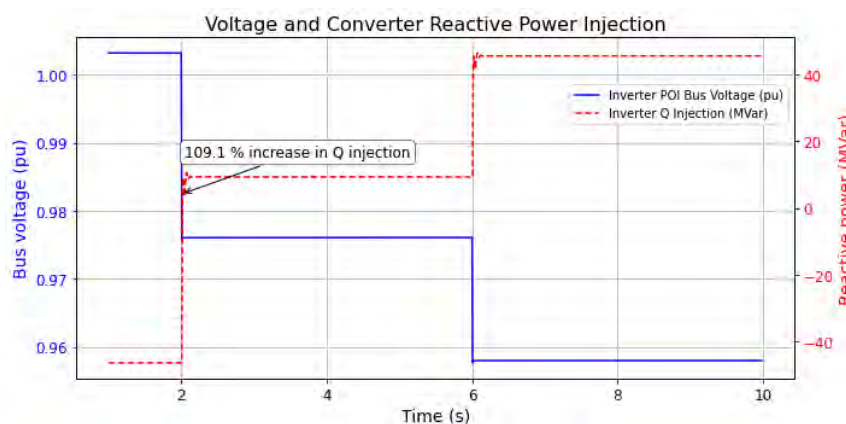


Figure 9: Low voltage test for VSC converter

Similarly, VSC-based HVDC systems can operate reliably under weak grid conditions. A weak grid can be emulated by increasing the impedance between the converter’s POI and the surrounding AC network, thereby reducing the Short-Circuit Ratio (SCR) seen by the converter. The SCR test has been explained in the [technical appendix](#).

These tests serve as proxies for validating the inherent behavior of HVDC dynamic models. In practice, system operators and planning engineers may require more extensive model validation to maintain planning accuracy and reliability. As discussed in the [Transmission Planning](#) section later in this paper, evaluating such dynamic reactive power benefits from HVDC also requires understanding what alternative sources of dynamic reactive support already exist and whether those sources would remain available independently of the HVDC line.

## FREQUENCY STABILITY SUPPORT

VSC-HVDC also supports frequency stability across all relevant timescales for frequency recovery through droop-based control and synthetic inertia. Inertia control makes the VSC converter respond to the rate of change of frequency (ROCOF) and can be emulated by using grid-forming control strategies that utilize the energy stored in the DC-link capacitors. These systems enable fast frequency responses, with active power modulation achievable within 10 to 50 milliseconds.<sup>9</sup> Primary frequency control is implemented through droop control mechanisms, analogous to those used in synchronous machines. Standardization around frequency response is found in ENTOS-e's HVDC Grid code.<sup>10</sup>

## CONVERTER-DRIVEN STABILITY RISKS

Despite all the stability benefits of HVDC, converter-driven stability issues may arise from dynamic interactions between HVDC converters and other power electronic devices, such as inverter-based resources (IBRs) or large converter-fed loads. While VSC-HVDC systems can improve local system strength, particularly in weak grid areas, they can also introduce or amplify control-based instabilities under certain conditions. Findings from the MISO RIIA indicate potential converter-driven stability concerns beginning at the 30% renewable penetration milestone. These concerns align with projections from the Regional Resource Assessment (RRA), which anticipates localized weak-grid conditions as renewable integration increases. Even the HVDC stability benefits are highly dependent on control system design, grid strength, and technology. Poorly tuned or uncoordinated HVDC systems may introduce adverse control interactions and degrade overall system stability.

As an example, converter interaction is found in the Dutch transmission system, where grid operator TenneT has reported persistent sub-synchronous oscillations beginning in 2024.<sup>11</sup> These oscillations typically occur in the 3.4 to 3.8 Hz range, with active power fluctuations around 30 MW and associated voltage variations of approximately 1% of nominal voltage. The events are most frequently observed during summer, particularly at mid-day, and are concentrated near HVDC terminals connecting lines to Denmark and Norway. These areas also host a high density of solar PV generation near the HVDC

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<sup>9</sup> Stojković, J., Lekić, A., & Stefanov, P. (2020). Adaptive Control of HVDC Links for Frequency Stability Enhancement in Low-Inertia Systems. *Energies*, 13(23), 6162. <https://doi.org/10.3390/en13236162>

<sup>10</sup> European Union, Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules, August 26, 2016, <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32016R1447#d1e211-1-1>

<sup>11</sup> Tennent, Investigation of persistent sub-synchronous oscillations in the Netherlands. March 2025. <https://www.esig.energy/download/session-4a-investigation-of-persistent-sub-synchronous-oscillations-in-the-netherlands-aleksandar-boricic/?wpdmdl=12932&refresh=67e1709f9b7551742827679>



interface. Phasor Measurement Unit (PMU) data has been essential in capturing and analyzing these oscillatory events.

In China's Xiamen HVDC project, oscillations occurred at 23.6 Hz when operating at 100 MW and shifted to 25.2 Hz at 500 MW, demonstrating a power-dependent frequency characteristic.<sup>12</sup>

In July 2015, China's Hami Wind Farm (a massive 3,000 MW installation of Type-4 wind turbines connected through a weak AC network and  $\pm 800$  kV HVDC) triggered sub-synchronous torsional oscillations around 27–33 Hz.<sup>13</sup> These oscillations, arising from interactions between full-converter turbines and the weak grid, propagated over 300 km and excited torsional modes in remote thermal power units. As a result, protection systems tripped multiple generators, causing a 600 MW loss in capacity and reducing HVDC export capability from 4,500 MW to 3,000 MW.

## STABILITY IMPACT RECOMMENDATIONS

As penetration of HVDC facilities increases, MISO should conduct, or coordinate with other entities to conduct frequency, voltage, and rotor angle stability risk assessments related to HVDC facility as well as assess converter-driven stability risks.

## HVDC OPERATIONAL MODELING, MONITORING AND CONTROL

### CURRENT MODELING PRACTICE

The network topology for MISO HVDC lines is currently modeled differently for the following three different scenarios as described in the [Market Impact Assessment](#) section:

1. Generation-lead intra-regional line
2. Bi-directional scheduled intra-regional line
3. Bi-directional scheduled inter-regional line

The network model supports various real-time analysis functions in the Energy Management System (EMS) such as state estimation, voltage stability analysis, contingency analysis, etc. The way an HVDC system is modeled directly affects what data must be delivered via SCADA. Currently, the SCADA model for HVDC systems includes the following:

1. AC Side Breaker Status
2. AC Side Measurements (MVA, MW, MVAR, and voltage values at the AC terminals)
3. DC Side Measurements (MW at both the sending and receiving ends; two readings for bipoles)

AC-side alarming is supported through both flow-based alarm limits and standard thermal alarms (typically three thresholds). No dedicated DC-side alarms are currently implemented in the SCADA system.

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<sup>12</sup> Yin, C., Xie, X., Xu, S., & Zou, C. (2018). *Review of oscillations in vsc-hvdc systems caused by control interactions*. The Journal of Engineering, 2019(16), 1204-1207. <https://doi.org/10.1049/joe.2018.8634>

<sup>13</sup> Y. Liu et al., "Stability Problems of Wind Power Integration with Weak AC Grids and Their Solutions," Journal of Engineering (IET), 2017. DOI: [10.1049/joe.2017.0612](https://doi.org/10.1049/joe.2017.0612)



The Inter-control Center Communication Protocol (ICCP) model manages the communication infrastructure that supports SCADA operations at MISO. This includes modeling inbound data received from customers and enabling outbound control signals sent by MISO. The system ensures reliable data exchange and real-time visibility across the grid. As HVDC systems are integrated, more detailed telemetries may be required, such as multiple MW readings, breaker statuses, and potential DC alarms. These could significantly increase the volume of data handled by the system. This growing data volume is an important consideration for maintaining system performance and scalability.

The operation of HVDC lines is influenced by how the market dispatch system is configured, such as whether it uses power dispatch or firing angle control, with dispatch targets typically set on a 5-minute interval. Currently, HVDC systems are not controlled through Automatic Generation Control (AGC) and therefore do not respond to 4-second regulation signals.

## MODELING IMPROVEMENTS

Since HVDC lines are modeled using a generation-load approach, this has eliminated the need to explicitly represent the HVDC link in steady-state reliability studies. However, in the future, HVDC line loss modeled as a contingency may be needed to better capture their potential impact on system stability.

Existing real-time applications such as State Estimator (SE), and Contingency Analysis (CA) already have capabilities to incorporate HVDC system modeling with minimal enhancement. For example, Constraint Logger (Clogger) supports sensitivity calculations within its existing framework and can model a controlled reduction in power transfer through HVDC, often referred as runbacks, to quantify the resulting relief on AC line flows. However, the ability to model a runback in studies is separate from the ability to execute it in real-time. Operational implementation would require that the HVDC facility support automated runback capability, as well as the installation of reliable, secure communications for real-time activation.

If HVDC facilities are used for regulation services or dispatched directly, the dispatch logic and modeling formulation need to be coordinated with application vendors. This might represent a substantial shift in operational monitoring and control practices. Additional monitoring capabilities may also be required, including PMUs, and angle controller visualization for real-time angle tracking.

## ADVANCED HVDC MONITORING AND CONTROL

An interregional HVDC link can play a critical role in improving frequency stability by providing fast balancing power support across asynchronous areas. Unlike conventional generators, which are constrained by mechanical inertia and governor response, HVDC systems can respond almost instantaneously to frequency deviations, thereby acting as a highly effective stabilizing resource.

A previous study evaluated how decentralized HVDC frequency controllers can improve system frequency response between the Eastern Interconnection (EI) and the Western Interconnection (WI) in the U.S. under a large disturbance.<sup>14</sup> The test scenario considered a simulated trip of a large generating unit in WI, resulting in a sudden drop in frequency. The decentralized controller provides fast response

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<sup>14</sup> Frequency Response and Congestion Management using Multi-terminal HVDC overlay.  
<https://www.osti.gov/servlets/purl/1817447>

and shows improvement in both the lowest frequency point (nadir) and the settled final frequency. The control scheme increases power injection into the WI when its terminal frequency is low by utilizing the spinning reserves available in the EI to support the WI during the generation loss event.

From a centralized control perspective, HVDC fast power modulation can also be used for wide-area control. Assuming PMUs are installed at key locations in a network, their synchronized measurements can be leveraged in the control room to compute overall network stress in nearly real-time. The [technical appendix](#) formulates an Integral Square Bus Angle (ISBA) index that measures the overall network stress in terms of phase angle differences in the system.<sup>15</sup> A higher ISBA value indicates larger overall angle differences between buses, which means that the system is more stressed or closer to instability.

A response-based, centralized HVDC control scheme is a key application for such real-time indices. For example, if the rate of change of the phase angle difference exceeds a predefined threshold indicative of rapid angular divergence, the control center can automatically trigger a fast HVDC transfer (e.g., 500 MW). Such action would require advanced wide-area monitoring (e.g., PMUs) and automation can be done using machine learning algorithms trained to detect early signs of instability for fast control actions.

## CONTINGENCY IMPACTS

### CURRENT LANDSCAPE

One example of how an HVDC system can eliminate contingency constraints is the DC runback scheme implemented for Manitoba Hydro. The Manitoba Hydro system relies on HVDC bipoles to deliver bulk power from hydro-stations in northern Manitoba to southern Manitoba, where the power is then transferred to other Canadian provinces and into the MISO system through multiple AC tie lines. During periods of surplus generation in Manitoba, these AC ties become critical export paths. However, if one of the AC tie lines becomes overloaded or trips, the power it was carrying is redistributed onto the remaining parallel AC lines. This sudden redistribution can push those lines beyond their thermal limits, creating the risk of cascading outage across multiple tie lines. To mitigate this risk, Manitoba Hydro employs HVDC runback schemes that leverage HVDC's fast controllability to automatically reduce DC power injections into the AC grid during tie-line contingencies. Simulation of tie-line loss events with MISO have shown that, *without runback action*, post-contingency flows on the remaining parallel lines immediately exceed their emergency ratings after fault clearance.<sup>16</sup>

A sudden loss of an HVDC bipole can withdraw large amounts of power from the system, potentially representing the most severe contingency. For HVDC lead lines proposed to connect significant amounts of remote generation, a bipole trip may require an immediate subsequent trip of the remote generation because other facilities might not be in place to unload such generation. Depending on the magnitude of

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<sup>15</sup>S. M. Rovnyak, M. N. Nilchi, D. W. Longbottom and D. C. Vasquez, "Angle stability predictive indices," 2012 IEEE Power and Energy Society General Meeting, San Diego, CA, USA, 2012, pp. 1-6, <https://doi.org/10.1109/PESGM.2012.6344976>

<sup>16</sup>N. V. Raju, A. D. Rajapakse, I. T. Fernando and D. Diakw, "Wide area synchrophasor measurements-based ac/dc integrated remedial action scheme for overload prevention," 15th IET International Conference on AC and DC Power Transmission (ACDC 2019), Coventry, UK, 2019, pp. 1-6, <https://doi.org/10.1049/cp.2019.0038>



such a generation trip, there could be adverse impacts to the interconnection including potential underfrequency load shedding (UFLS).

Although the NERC's 2004 Frequency Response Standard Whitepaper<sup>17</sup> is relatively dated, it provides insights that remain relevant to understanding frequency response of the Eastern Interconnection (EI). It reported an average EI frequency response of 3100 MW/0.1 Hz which means the first tier of UFLS at 59.7 Hz would be triggered at 9300 MW given the frequency declined from the nominal 60 Hz. Even with a reported declining rate of about 70 MW/0.1 Hz per year, UFLS vulnerability to a 2400 MW loss was projected after 34 years, which is a timeframe just around the corner today. While a merchant HVDC bipole trip resulting in a subsequent generation trip of 3000-5000 MW may or may not trigger UFLS today, it is prudent to study this possibility. NERC's whitepaper also did not foresee large-scale synchronous generators retirements, widespread IBR adoption, or high electronic load growth, all of which may worsen the issue, nor did it anticipate battery-based fast frequency response, which could help mitigate it.

Brazil's Rio Maderia project and Itaipu HVDC project (both consisting of two +/- 600 kV bi-poles each rated at 3,150 MW) connect remote generation resources relying on the HVDC links for injection into the system. When a bipole is blocked, these generations become electrically disconnected, causing a sudden drop in frequency in the receiving regions. On the other hand, for intra-regional or embedded HVDCs such as Brazil's Xingu bipoles ( $\pm 800$  kV each at 4,000 MW), a loss of the bipole causes an immediate redirection of power through the parallel AC corridors. This redirection leads to rapid increase in power-flow across long-distance loaded AC lines, potentially exceeding stability margins and causing voltage collapse.

To mitigate these effects, ONS system operators in Brazil have employed multi-tiered response strategies including an automatic run-up of remaining bipoles up to their short-time overload capacity, activation of Special Protection Schemes (SPS) to command generation tripping, and controlled load shedding.

## CONTINGENCY IMPACT ASSESSMENT

Contingencies involving large HVDC lines can create disproportionate operational impacts due to the sudden and significant loss of power transfer. When such line trips offline, system frequency declines rapidly, with the rate-of-change-of-frequency (RoCoF) depending on the magnitude of the outage and the available system inertia. In lower-inertia conditions, this can result in widespread IBR tripping, potentially triggering under-frequency load shedding (UFLS), and immediate activation of spinning reserves.

Under these types of disturbances, Area Control Error (ACE) spikes sharply, straining automatic generation control (AGC) systems and dispatch logic. Large shifts in power flow across tie lines and constrained interfaces can lead to thermal overloads and dynamic stability risks. Deliverability of contingency reserves becomes critical, particularly when reserve-sharing arrangements across Balancing Authorities are limited.

Under NERC BAL-002-3, the HVDC line may be classified as a single balancing contingency if its full loss is considered credible, requiring reserves equal to its full rating. This classification can significantly increase

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<sup>17</sup> <https://studylib.net/doc/8926789/frequency-response-standard-whitepaper>

reserve procurement requirements and operational costs. The MSSC must be determined and updated accordingly, and the value communicated to the Contingency Reserve Sharing Group (CRSG) as required under BAL-002-3 R1 and R2. MISO's current MSSC is 1732 MW. An annual review of MSSC is completed during November/December each year.

The loss of a large HVDC line can degrade voltage support and alter power flow distributions across the network. Inertia conditions may be particularly stressed during periods of low load or high IBR penetration. In multi-BA or multi-ISO environments, as is the case across the Eastern Interconnect, the reserve response to such a contingency must be coordinated and verified in advance. Real-time evaluation should confirm whether the event leads to ARS (automated reserve sharing) triggers or affects use of external asynchronous resources (EARs), such as those seen in Manitoba-related events. For instance, run back schemes should be coordinated with external resource owners.

## **CONTINGENCY IMPACT RECOMMENDATIONS**

To mitigate the risks associated with HVDC contingencies, several measures can be taken. As a part of the contingency management procedure, MISO should continue to update the MSSC and contingency reserve requirements as system conditions evolve to ensure reliability. As HVDC penetration increases, MISO should assess the risk of contingency reserve cost increases and evaluate opportunities to mitigate these increases through reserve sharing agreements or alternative cost allocation processes.

Within the post-contingency timeframe, it is necessary to assess both transient stability and dynamic response of the system. Frequency response losses must be quantified, and any generation redispatch or additional load shedding actions identified. Existing remedial action schemes (RAS) or special protection systems (SPS) relevant to the HVDC facility should be reviewed to ensure appropriate triggering and containment logic.

Market systems may need to assess whether sufficient ramping and reserve capability exists post-contingency. Changes in reserve obligations or delivery timelines may occur depending on how the event is classified and responded to.

Finally, operational readiness must be ensured. Control room operators should be trained for HVDC-specific outage scenarios, including appropriate notification and escalation procedures. Post-event analysis and regulatory filings may be required depending on the size, cause, and consequence of the event.

## **RELIABILITY COORDINATION**

To support the reliability of System Operations, MISO's current outage coordination process, as outlined in BPM-008, provides a robust framework for planning, analyzing and managing transmission and generation outages through tools such as CROW and AFC evaluations. However, as the system footprint increasingly integrates large-scale HVDC facilities, the traditional outage coordination framework faces new challenges. Unlike conventional AC lines, HVDC outages can cause high-magnitude and complex impacts that extend beyond thermal constraints. A bipole outage, for instance, may represent several thousand megawatts of sudden power transfer loss or redirection, significantly influencing voltage stability, inter-area oscillations, and reserve deployment. Moreover, HVDC systems involve converter stations, DC cables, and associated reactive support equipment, each of which may require maintenance





or experience partial outages that needs to map neatly into existing AC outage categories. Partial outage or derate causes temporary reduction in the transfer capability that affects operations and must be represented accurately in operational and planning models.

## **RELIABILITY COORDINATION RECOMMENDATIONS**

As HVDC systems become operationally flexible, outage coordination will need to increasingly incorporate functional performance and stability assessments. MISO could evaluate more granular representation of partial outages or de-rates during outage coordination. Transmission operators must submit planned maintenance outage schedules that include reactive device outages related to HVDC facilities. All active outage records, including those for HVDC related facilities, will be used in MISO's AFC calculation process and posted to NERC System Data Exchange (SDX) system for use in congestion management. Operational planning needs to increasingly incorporate specialized contingency screening, including NERC TPL-001 standard P6 and P7 contingencies to include the loss of single pole and bipole HVDC due to a short-circuit fault.

The maintenance of HVDC and its components must be monitored. As for example, CAISO monitors the maintenance practices of transmission facilities, including HVDC systems, in accordance with Appendix C, Section 4 of the CAISO Transmission Control Agreement (TCA). This section establishes the availability measures used to evaluate the effectiveness of transmission owner's maintenance programs. For HVDC facilities, these measures include indices such as the Annual Average Forced Outage Frequency, and Annual Average Forced Outage Duration, calculated using forced outage data. Scheduled outages and any events not classified as forced outages are excluded from these calculations. Transmission owners are required to include descriptions of maintenance activities for DC components within their stations in their annual maintenance reports. An example of such reporting is the Trans Bay Cable annual net availability report, which provides data on overall HVDC system performance.<sup>18</sup>

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<sup>18</sup> <https://www.caiso.com/documents/trans-bay-cable-transmission-availability-report.pdf>

## 4 Resource Adequacy Impact Assessment

Resource adequacy (RA) refers to the ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability. One such measure of reliability is the industry-accepted 1-day-in-10 years Loss of Load Expectation (LOLE) target. This section provides an overview of how External Resources and transmission are currently treated in MISO's resource adequacy construct, updates which are currently being considered by MISO, and additional options that could be explored to represent the impact of HVDC-enabled facilities on resource adequacy.

### Key Insights

- **External Resources are accredited in the PRA:**  
Existing rules allow for External Resources transferring power into MISO to participate in the MISO PRA
- **LOLE model is transmission-less:**  
The model includes and recognizes estimates of imports and exports between Regions, External Region interactions with the MISO system not explicitly modeled

### Recommendations

- **Resource adequacy treatment of external resources, including those delivered via HVDC:**  
MISO should collaborate with stakeholders to clarify how external resources, including those delivered by HVDC-enabled firm transmission, are modeled and participate under MISO's current resource adequacy construct.
- **Accreditation enhancements for external resources:**  
MISO should evaluate updates to external resource accreditation to improve alignment with the Direct Loss of Load/resource adequacy hours approach.
- **Representation of transmission in resource adequacy risk modeling model:**  
MISO could evaluate approaches to incorporating transmission, including HVDC facilities, into resource adequacy risk modeling.

### MISO RESOURCE ADEQUACY CONSTRUCT OVERVIEW

In the MISO footprint, the primary responsibility for achieving resource adequacy resides with Load Serving Entities (LSE) with oversight by Relevant Electric Retail Rate Authorities (RERRA), as applicable by jurisdiction. MISO facilitates these efforts by administering its Open Access Transmission, Energy and Operating Reserve Markets, tariff-defined Resource Adequacy Requirements (RAR) and the Planning Resource Auction (PRA), which LSEs use to demonstrate their ability to contribute to resource adequacy and provide a sufficient margin of excess supply. Following FERC's acceptance of MISO's Seasonal Resource Adequacy Construct and Seasonal Accredited Capacity filing, MISO now sets the LOLE-based Planning Reserve Margins on a seasonal basis for each PRA.<sup>19</sup>

MISO facilitates the annual PRA where resources offer capacity (MW) that can be used to meet the demand and reserve obligations of LSEs that are determined from a combination of their peak demand

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<sup>19</sup> Filed in August 2022, effective with MISO's Planning Year 2023-2024 PRA.



forecasts and the modeling results of the LOLE study. In preparation for the annual PRA, MISO conducts a probabilistic LOLE study to determine Resource Adequacy Requirements for the upcoming Planning Year. The LOLE study calculates the Planning Reserve Margin (PRM) to achieve the annual LOLE target, as well as minimum LOLE targets by season. These requirements are identified on a seasonal basis within MISO. In addition to the PRM, Local Reliability Requirements for each Local Resource Zone (LRZ) are determined for each season of the upcoming Planning Year and represent the capacity that must be held internally in each zone to achieve the reliability requirement.

The LOLE study assumes no transmission limitations within the model and does not directly model transmission. The MISO Tariff explicitly excludes transmission considerations in the modeling that sets capacity requirements.<sup>20</sup> Although transmission is not considered in the LOLE analyses, import and export capabilities with external systems are considered in MISO's PRA indirectly through both firm and non-firm external support. Additionally, Capacity Import Limits (CIL) and Capacity Export Limits (CEL) are considered when setting the LRZ requirements in the PRA.

Under MISO's current resource adequacy construct, all Planning Resources that qualify to participate in the PRA will have a Seasonal Accredited Capacity (SAC) value determined by MISO. Planning Resources consist of Capacity Resources, Load Modifying Resources, and Energy Efficiency Resources. Capacity Resources consist of Generation Resources, Electric Storage Resources, External Resources, and Demand Response Resources. Load Modifying Resources consist of Behind the Meter Generation and Demand Resources. Energy Efficiency Resources<sup>21</sup> are resources registered with MISO that permanently reduce electricity Demand.

MISO does not determine explicit capacity credit for transmission lines (both HVAC and HVDC). External Resources can participate in the MISO PRA regardless of whether they are transferring power into the MISO footprint through the HVAC or HVDC lines provided they meet the qualification criteria as documented in MISO's Resource Adequacy [Business Practices Manual BPM-011](#).

## EXTERNAL RESOURCES IN THE RESOURCE ADEQUACY CONSTRUCT

MISO's resource adequacy construct allows firm/contracted resource to earn capacity credit in the PRA. Transmission enables internal and external resources to participate in the MISO capacity market but transmission alone does not earn capacity credit. Instead, transmission enables the resources utilizing it to participate in the PRA and the MISO Energy Markets. No RTO in North America currently allows transmission lines to earn capacity credit. Every RTO only accredits Resources. A key consideration in the evolving capacity accreditation practices is whether - and under what circumstances - transmission facilities themselves should be eligible for earning capacity credit. Implementing such a change would represent a significant shift from the current approach, which only accredits Resources utilizing those facilities.

MISO requires capacity cleared in the PRA to be dedicated exclusively to the MISO Region. The same generation resource cannot earn capacity credit in two different RTO Regions for the same portion of the

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<sup>20</sup> MISO Tariff 68A.2 - Planning Reserve Margin Analysis

<sup>21</sup> MISO filed to remove Energy Efficiency Resources from the PRA in FERC Docket No. ER26-148 on October 15, 2025.



resource. In addition to the requirement that committed capacity be exclusive to MISO, a demonstration of ownership or contractual obligation is required.

Without an attestation that generating capacity is proven and dedicated to MISO, significant modeling and external coordination would be required to have a reasonable expectation of expected reliability. In addition to modeling and coordination concerns, allocating capacity credit to transmission lines would require some method to separate the reliability benefits provided by transmission lines from the reliability benefits provided by generators using the transmission lines. This methodology could be complicated even if it were determined to be feasible and would require additional processes to avoid double-counting expected reliability benefits.

Although MISO does not currently accredit transmission, External Resources can earn accreditation and participate in the PRA based on ownership (direct or joint), firm contracted capacity, or using a slice-of-system approach. Each of these frameworks provides a potential option for HVDC-enabled external resources to participate directly in the MISO PRA.

- i. Market Participants can register External Resources that they have either direct ownership or joint ownership of for one or more seasons in the PRA. If owned, a Market Participant may also choose to register an External Resource in MISO's Network and Commercial Models through a pseudo tie.
- ii. An External Resource registration that is backed by a Power Purchase Agreement (PPA) is often referred to as firm contracted capacity. To register this type of External Resource, the Market Participant would need to provide MISO with the proper documentation, including but not limited to a copy of the PPA, that demonstrates the entitlement to the specific amount of capacity they are seeking to register and the specific generator(s) comprising the External Resource registration.
- iii. A Market Participant may also register a pool of two or more generators as a slice-of-system External Resource. Slice-of-system External Resources that participate in MISO are registered through a type of PPA which guarantees seasonal or annual capacity commitments from a pool of resources physically residing in an external system. The requirements of a standard PPA described in provision (ii) would also apply to a slice-of-system PPA. Additionally, a slice-of-system PPA may involve a diversity exchange arrangement wherein, during specific months of the year, capacity from MISO-internal resources is exported to support an external system and vice-versa during other specified months. In the case of diversity exchange agreements, the MISO-internal capacity being exported is excluded from accreditation in applicable seasonal auction(s) of the PRA as it would be unavailable to serve MISO load.

External Resources are referred to as Firm External in the LOLE Study Report and must meet the following requirements:

- Seasonal Accredited Capacity (SAC) is based on seasonal Generator Verification Test Capacity (GVTC) and seasonal 3-year average forced outage rates, if GADS-reporting. If a non-GADS resource, SAC is based on historical availability during MISO system coincident seasonal peak hours.



- Requires firm transmission to the MISO border and from the border to an identified MISO sink.

Firm External Resources are accounted for as a line item in the seasonal PRM calculations. Exports to other areas (such as PJM and SPP) are accounted for in the LOLE model and in the Planning Resource Auction based on PJM's Reliability Pricing Model (RPM) as well as the MISO Independent Market Monitor (IMM) exclusion list.

External resources that clear the PRA have a Must Offer requirement in the Day-Ahead Energy Market as outlined in Section 6.1.4 of [MISO's Resource Adequacy Business Practices Manual \(BPM 011\)](#).

External Resources that clear the PRA get the External Resource Zone (ERZ) pricing, unless they are a Border External Resource or a Coordinating Resource. If a Border External Resource or a Coordinating Owner External Resource (Manitoba Hydro), they would get the ACP of the sink zone and are treated as if they were an internal Resource in the model.

A Border External Resource is an External Resource that:

- has direct interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control;
- will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to such substation; and,
- whose Unforced Capacity offered into MISO may be accommodated on those transmission line(s) under the Transmission Provider's functional control.

The LOLE probabilistic analyses for Planning Year 2026-2027 assumed between 1.0 – 1.3 GW of firm imports, depending on the season, as shown in Table 3-16 of the [Planning Year 2026-2027 Loss of Load Expectation Study Report](#).

## TREATMENT OF TRANSMISSION IN THE LOLE MODEL

The current LOLE model does not include the limitations that transmission imposes on the transfer of power across the MISO footprint. MISO incorporates non-firm external support as seasonal probabilistic distributions within the LOLE Model. Non-firm support is estimated using historical Net Schedule Interchange (NSI) and removes any participating firm external capacity as well as firm exporting capacity as identified by the Independent Market Monitor and PJM's Reliability Pricing Model (RPM).

The non-firm support represents the amount of non-firm energy MISO could reasonably expect on a real-time basis to meet electricity demand while accounting for the transmission constraints between MISO and external areas, as well as the amount of excess available energy that external areas would be able to offer MISO after serving the external Region.

Non-firm support is not a line item in the PRM calculations but is accounted for when determining the adjustment needed to reach seasonal LOLE criteria. The inclusion of non-firm support in resource adequacy modeling results in lower seasonal PRMR as it offsets the need for a more positive adjustment to capacity in the model to reach seasonal LOLE criteria.

HVDC transmission today can enable Firm External Resources to participate in the MISO PRA for capacity credit and can additionally provide non-firm support contributing to overall reliability. Under the

current construct, an HVDC line does not need to be explicitly included if the HVDC-enabled External Resources are included in the model. Estimating the reliability contributions of an HVDC line, independent of the resources involved, would likely require incorporating transmission into the LOLE model, some knowledge of how the capacity is showing up in energy markets, and explicit modeling of External Regions in the LOLE model. Inclusion of these factors would increase the complexity of the LOLE model.

MISO is exploring whether and how to incorporate the effects of transmission in the LOLE model, which is expected to add significant complexity to the model. MISO anticipates that HVDC and HVAC transmission may need similar considerations to be included in the model.

## A NEW ACCREDITATION FRAMEWORK

Beginning in PY 2028-2029, MISO's DLOL methodology for accrediting all resources (except Load Modifying Resources and External Resources) measures a resource's availability when reliability risk is greatest. Direct Loss of Load (DLOL)-based accreditation is based on the modeled capabilities of Resource Classes and is allocated by an evaluation of the historical performance of specific resources within a Resource Class.

DLOL accreditation will be determined in a two-step process:

- The Resource Class-level step sets the "size of the pie" for each of the thirteen Tariff-defined Resource Classes which is determined using probabilistic risk modeling by measuring resource availability during simulated high-risk hours.
- The Resource-level step determines how large each "slice of the pie" is by evaluating a specific resource's historical availability during historical high-risk hours. Resource Class-level accreditation is then allocated to each individual Resource within a given Resource Class.

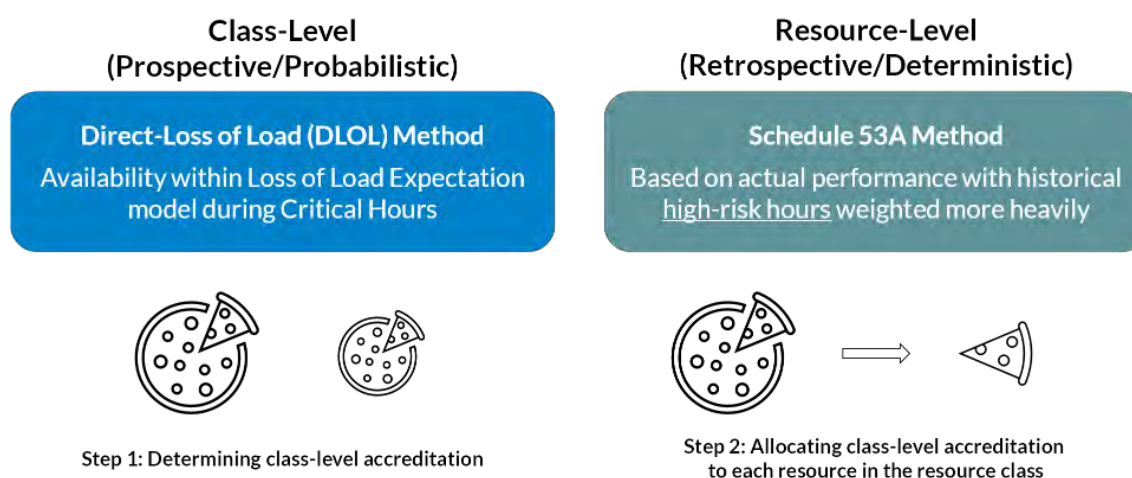


Figure 10: DLOL Accreditation

Although the accreditation of External Resources was not included in the recent reforms adopting DLOL accreditation, MISO plans to begin an evaluation of External Resource accreditation as a next step in



Resource Accreditation Reform. In collaboration with stakeholders, MISO plans to evaluate External Resource accreditation in the PRA to align with the DLOL framework that was approved by FERC and is going into effect starting with Planning Year 2028-2029. Consideration of HVDC-enabled capacity will be an important part of this work.

## RESOURCE ADEQUACY MARKET DESIGN

MISO has explored a wide range of potential accreditation approaches for new HVDC-enabled resources. MISO understands and acknowledges that the new HVDC-enabled resources can contribute to reliability and resource adequacy of the MISO system. However, incorporating HVDC into existing resource adequacy processes or developing any new processes cannot be isolated from a holistic assessment of overall HVDC integration.

As described above, External Resources today can participate as Firm External Resources. MISO has identified a few options for incorporating HVDC transmission into the resource adequacy construct. Table 2 lists options that would need to be evaluated before figuring out changes to the design for HVDC's role in the MISO resource adequacy construct, specifically accreditation and reliability requirements calculations. Although MISO is not actively exploring any of these options at this time, this list is intended for discussion purposes. Any options would need to be evaluated for complexity, feasibility, accuracy, and other factors. These options are presented in order of increasing complexity, with the first items on the list being available with little to no changes to current systems, and the latter ones requiring the largest potential changes to MISO systems and models.

| Option                                                                                 | Summary                                                                                         | Anticipated Considerations                                                                                                                            |
|----------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------|
| Continued use of External Resource Accreditation                                       | Credit firm external resources, non-firm imports are socialized                                 | Resource Class definitions may be needed for HVDC-enabled External Resources                                                                          |
| Credit HVDC line based on performance during resource adequacy hours                   | HVDC line modeled and accredited separately from other non-firm external support                | Potentially difficult model changes needed to differentiate the impact of HVDC assistance from other external support                                 |
| Expand Zonal Deliverability Charge (ZDC) Hedges to include merchant-built transmission | Allowing merchant HVDC to have an option similar to ZDC-hedge in MISO Tariff Section 69A.7.7(b) | ZDC hedges have not been exercised and are currently only available to LSEs providing benefit for investment and would require stakeholder discussion |
| HVDC Direct Loss of Load (DLOL)/Resource Adequacy Hour accreditation                   | HVDC-enabled assistance accredited based on DLOL accreditation design                           | Potentially requires detailed modeling of and coordination with External Regions                                                                      |

Table 1: Evaluation of options for HVDC role in the MISO resource adequacy construct

## CONTINUED EXTERNAL RESOURCE ACCREDITATION

The default option is to continue with MISO's current market design with no major changes to the construct. Under the status quo, HVDC lines are not provided with explicit capacity credit but act to



enable firm and non-firm support from external areas. As a part of MISO's evaluation of External Resource accreditation reforms there still may need to be some adjustments needed due to HVDC-enabled Resources such as new Resource Class definitions for external classes.

### **CREDIT HVDC LINES BASED ON PERFORMANCE DURING RESOURCE ADEQUACY HOURS**

Another option could provide accreditation to HVDC lines based on performance during Resource Adequacy (RA) hours. Under this option, the expected reliability contribution from an HVDC line would be evaluated based on the power delivered by the HVDC lines during challenging operational hours, like how performance for internal Resources are calculated under Schedule 53.<sup>22</sup> HVDC lines would not be explicitly included in the model, but their impact would have to be carved out from non-firm import assistance.

No data would be available for the first year of operation for new lines which would require developing a default methodology for new HVDC lines. It could also prove difficult to estimate accreditation in forward-looking assessments without sufficient operating histories. An alternative would be for new lines to start with no accredited value until sufficient historical data is available to measure historical performance.

Although the impact on the model may not be large, model modifications would be needed to differentiate the impact of HVDC assistance from other external support (e.g., a reduction of expected assistance from non-firm imports). Additional challenges include how the line will be registered and operated, as well as how Resource Adequacy (or capacity) obligations would be assigned.

### **EXPAND ZDC HEDGES TO INCLUDE MERCHANT-BUILT TRANSMISSION**

The current tariff allows an LSE to benefit from transmission investment that is shown to alleviate transmission congestion and, as a result, lower internal zonal capacity obligations in the form of a Zonal Deliverability Charge (ZDC) Hedge. A ZDC Hedge allows protection against zonal price separation in instances where the Auction Clearing Price (ACP) of the LRZ where the Resource is physically located is less than the ACP of the exporting LRZ whose PRMR the Resource is being used to meet. ZDC Hedges have not been exercised historically and are currently only available to LSEs. Expanding this concept to merchant-HVDC investments would require further evaluation and stakeholder discussion.

### **HVDC DIRECT LOSS OF LOAD (DLOL) ACCREDITATION**

HVDC assistance could also be evaluated under the DLOL framework by using modeled transfers. This approach would require modeling of the external world in the LOLE model. At a minimum, it requires creating "bubbles" to represent neighboring regions and their capacity transfers to MISO. This would require collection and generation of data for those regions, including but not limited to, a list of resources (type, capacity, performance, maintenance, etc.), wind/solar shapes, load hourly shapes, and load

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<sup>22</sup> Under Schedule 53 and 53a, performance during resource adequacy hours is used to distribute the Resource Class DLOL accreditation among individual resources. This is captured in Figure 10 (DLOL Accreditation). While that would remain unchanged for internal resources, this option proposes to calculate the average contribution of each HVDC. HVDC lines would likely not have a Resource Class accreditation determined through the LOLE model.





forecasts. This more detailed representation of the MISO neighbors would result in a significant increase in model complexity, and effort needed to update and maintain the model every year.

A benefit of this increased modeling complexity is forward-looking assessments that could estimate the impact of those imports. Those updates would also be more complex because they would require representing future portfolios and scenarios for the modeled neighboring regions.

As with other options, introducing DLOL accreditation for assistance from external regions may require coordination and tradeoff discussions with neighbors to ensure that MISO and its neighbors will get the expected benefit when either system is at a high risk for shedding load. External Systems may need to be fully incorporated into the model, which would greatly increase the complexity of reliability modeling. Coordination agreements may be required to ensure reliability across regions and may require adding transmission to the current transmission-less model. Benefits provided by Resources and by transmission would also need to be separated from one another.

## CONCLUSION AND NEXT STEPS

Several merchant HVDC transmission lines are being proposed for interconnection to the MISO transmission system. This section provides an overview of External Resource accreditation in MISO's resource adequacy construct, next steps in the reform of the construct, and additional options that could be explored to assess the impact of HVDC facilities on resource adequacy.

HVDC-enabled resources will need to be accounted for in the MISO resource adequacy construct by either utilizing existing processes or through the development of new processes. However, incorporating HVDC into existing resource adequacy processes or developing any new processes cannot be isolated from a holistic assessment of overall HVDC integration.

MISO has considered several mechanisms to incorporate HDVC transmission into the resource adequacy construct which are provided herein as a starting point for discussion. Many of the options under consideration could require significant changes to MISO's Loss of Load Expectation (LOLE) modeling as well as coordination and agreements with neighboring regions. As mentioned previously, MISO is planning to enhance the existing External Resource accreditation process as the next step in its Resource Accreditation Reform effort. HVDC-enabled resources will be a part of that evaluation effort. Additional changes to the resource adequacy construct would need to be evaluated and prioritized before moving forward with further evaluation.

Future work will focus on:

- Providing clarification regarding how External Resources, including those delivered by HVDC-enabled firm transmission, are modeled and participate under MISO's current RA construct.
- Evaluating accreditation of external resources to improve alignment with the Direct Loss of Load / Resource Adequacy (RA) Hours approach.
- Evaluating methods for incorporating transmission lines, including HVDC, into resource adequacy risk modeling.

## 5 Interconnection of Merchant HVDC Lines

This section discusses the MHVDC Interconnection Process only and is not applicable to HVDC transmission considered internally in MISO's Transmission Expansion Planning process. Tariff Attachment GGG describes the MHVDC Transmission Connection Procedure (MHCP), which was implemented in 2018. This procedure governs the method by which a Merchant HVDC transmission line external to MISO may connect to the Transmission System.

| Key Insights                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       | Recommendations                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"><li>• Several Merchant Interregional HVDC projects are being proposed in MISO MHVDC queue.</li><li>• Commercial value of Merchant Interregional HVDC depends on securing the right products and approvals, such as:<ul style="list-style-type: none"><li>○ Injection and/or Withdrawal rights</li><li>○ Deliverability</li><li>○ Limited-Operations provisions &amp; interim use, etc.</li></ul></li><li>• MHVDC needs strong interconnection planning modeling and coordination among all impacted parties- associated RTOs, interconnection customers, and transmission owners. etc.</li></ul> | <ul style="list-style-type: none"><li>• <b>Improvements to MISO Attachment GGG Process:</b> Stakeholders have requested clarification and streamlining of interconnection processes for Merchant HVDC facilities. These requests include the use of TSRs via Module B for Injection/Withdraw rights and the development of preliminary MHVDC study procedures to better service customers before the full Att. GGG studies. MISO is making Tariff language changes to Attachment GGG, updating the MISO MHVDC interconnection process, and making Limited Operation clarifications for interim periods on qualified MHVDC projects and will continue to engage with stakeholders on these issues through the IPWG and PAC.</li><li>• <b>HVDC Business Practice Manual:</b> Stakeholders have requested that MISO create a dedicated BPM to enhance clarity, efficiency, and alignment with Tariff provisions for the MHVDC interconnection process. MISO is creating an MHVDC BPM focusing on MHVDC application, application modification, application withdrawal, study scope, process timelines, study requirements, affected system studies, and Pre-TCA considerations.</li></ul> |

MISO has received several interregional MHVDC connection requests across multiple seams since 2019. Operationalizing each of these requests will require strong interconnection planning modeling and close coordination between MISO, the MHVDC interconnection customer, impacted Transmission Owners, and neighboring Regional Entities.

### CURRENT STATE OF MISO'S MERCHANT HVDC INTERCONNECTION PROCESS

Figure 11 below shows the major steps of the MHVDC Connection Procedure, which begins with a Transmission Connection Request (TCR) and ends with an executed Transmission Connection Agreement (TCA). Applications for MHVDC Transmission Connection Service are processed on a first-come, first-serve basis.

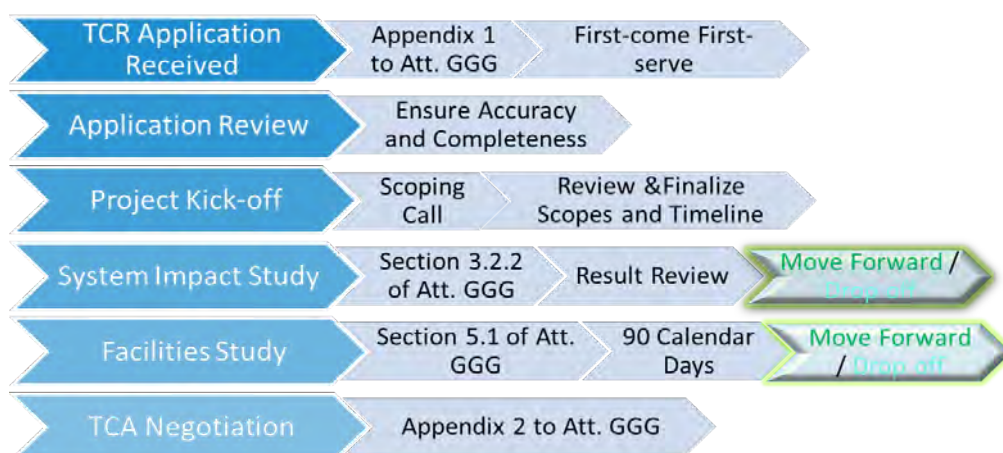


Figure 11: MHVDC Connection Procedure Steps

## ACTIVE PROJECTS IN MISO'S MHVDC INTERCONNECTION QUEUE

MISO's MHVDC Interconnection Queue currently contains the following three projects, all of which are targeting commercial operation in the 2030-2032 timeframe:

- North Plains Connector (NPC) – A proposed bi-directional HVDC transmission project in the Northern Plains region intended to facilitate transfer capability between the western and central U.S. grids, with a proposed interconnection into the MISO footprint.
- Grain Belt Express (Phase 1) – A proposed multi-phase HVDC transmission project designed to deliver energy from the central Plains region into the Midwest, with an announced future extension concept to enable delivery farther east.
- SOO Green – A proposed underground HVDC transmission project intended to move power between Iowa and northern Illinois, with planned interconnections in the MISO and PJM regions.

Project descriptions are based on publicly announced information; specific interconnection request configurations, POI details, study status, and queue positions may be confidential and are not reflected here.

All MHVDC projects submitted to MISO, including those completed, withdrawn, active, or queued, are publicly disclosed on [MISO's website](#).

## MHVDC PROCEDURES IN OTHER ISO/RTOS

The following is a short summary of policy notes on MHVDC processes hosted by other regional entities (SPP, NYISO, and ERCOT) based on publicly available information.

### Southwest Power Pool (SPP)

- SPP allows merchant HVDC, with structured interconnection and service request processes.
- SPP's Tariff Attachment AR governs this MHVDC interconnection process.

Recent revisions of the process require demonstration of site control, more formal milestone tracking, and clarity around modifications (very similar in spirit to pending MISO Attachment GGG improvements).



## New York ISO (NYISO)

- NYISO has a special Interconnection Service Agreement (ISA) process for MHVDC facilities.
- Deliverability studies are fully integrated into the Class Year process.
- MHVDC projects are treated under the developer-funded interconnection model, and the developer is responsible for any required transmission system upgrades.
- Limited operations (e.g., pre-commercial testing) are handled case-by-case but must comply with NYISO's Tariff and Operating Procedures.

## Electric Reliability Council of Texas (ERCOT)

- ERCOT requires that most HVDC projects must demonstrate no adverse operational impact on ERCOT system reliability.
- All costs are developer-funded; there is no network cost allocation.
- MHVDC ties are typically operated in a controlled flow mode to prevent unscheduled interchange.

## MERCHANT HVDC INTERCONNECTION FUTURE STATE - PROCESS IMPROVEMENTS

After gaining experience with Merchant HVDC transmission connection procedures outlined in MISO's Tariff Attachment GGG, both MISO and stakeholders have identified opportunities for improvement and efficiencies to benefit future MHVDC projects. This will include changes in both the Tariff and Business Practice Manuals, and is captured as "Attachment GGG Improvements" on the MISO Dashboard in [Issue PAC-2024-6](#).

The general workplan for improvement is expected to proceed in three phases, subject to change and stakeholder feedback, with expected completion by the end of 2026.

- Phase 1 includes creating a new Business Practice Manual dedicated to the current process, updating the MHVDC application process, clarifying withdrawal rights, and initiating a limited operations framework for MHVDC projects that require network upgrades. This work is actively in progress.
- Phase 2 includes clarification of Necessary Upgrade and Network Upgrade definitions within Attachment GGG, and other clarifications within the Transmission Connection Agreement (TCA).
- Phase 3 will include changes to Module B Transmission Service provisions to consider MHVDC injection and withdrawal rights. Currently, MHVDC projects seeking injection rights are limited to requesting these in the Generation Interconnection queue via Attachment X.

## 6 Transmission Expansion Planning of Intra-regional HVDC Lines

Any future intra-regional HVDC solutions selected in a future regional planning process will likely require automatic controls, which could include phase angles controls that simulate the performance of a proxy AC line, or the line could be dispatchable and co-optimized with resource outputs via the security constrained economic dispatch algorithms that clear the real-time market on a five-minute basis. Other control configurations could be explored as well.

### Key Insights

- For lines longer than 400 miles in length, HVDC tends to have a lower cost per MW mile.
- For lines shorter than 250 miles in length, EHV AC tends to have a lower cost per MW mile.
- For lines in the 250-50-400-mil length, the cost of HVDC vs. EHV AC should be determined on a case-by-case basis.
- For scenarios where granular flow control capability is desired, HVDC lines have an advantage.
- For scenarios where natural flow response is desired, EHV AC lines have an advantage.
- VSC HVDC lines can potentially provide dynamic reactive power and other ancillary benefits, but such benefits only exist if not already available from other nearby facilities such as conventional synchronous generation over inverter-based generation that must be installed to facilitate resource interconnections.

### Recommendations

- **Test modeling and performance of PROMOD HVDC simulation capabilities:** As a medium priority, MISO should test the modeling and performance of the dispatchable and co-optimized HVDC capability of PROMOD to ensure it is an acceptable proxy for the dispatchable HVDC solution to be developed by the market side.
- **Investigate feasibility of AC line emulation controls:** MISO could further investigate the feasibility of AC line emulation controls as an option for future regional HVDC lines where AC response is desired, but the line length is too long for an AC line.

### MISO CURRENT STATE

Intra-regional HVDC lines represent lines that are entirely within the MISO region and are planned by MISO. Any intra-regional HVDC line that is planned by MISO will be under full functional control of MISO including full five-minute dispatch control. For MISO to plan an intra-regional HVDC line, the ability to dispatch and co-optimize an intra-regional HVDC line must be developed, tested, and approved by the MISO markets and operations organizations as a valid option.

## MISO FUTURE STATE

### TRANSMISSION CAPACITY IMPACTS OF LINE LENGTH FOR EHV AC VS. HVDC LINES

The main consideration when comparing EHV-AC solutions versus HVDC solutions is the cost per MW-mile of each choice. Therefore, it is important to understand the limits of EHV AC lines vs. HVDC lines and how these loading limits are impacted by line length.

The capacity of an HVDC line is typically limited by two considerations whereas the capacity of an EHV AC line is typically limited by three considerations.

#### THERMAL LIMITS

Both HVDC lines and AC lines are limited by thermal limits, which represent the maximum operating temperatures for all load carrying electrical facilities and equipment. For HVDC lines, this includes the line conductors, the converters at each terminal and the AC terminal equipment at each terminal. For EHV AC lines, this includes the line conductors as well as AC terminal equipment at each terminal. Thermal limits are not a function of line length for either HVDC lines or AC lines.

#### MAXIMUM POWER TRANSFER LIMITS

HVDC and AC lines are also limited by a maximum power transfer limit that is unique to each line. For AC transmission lines, the maximum power transfer limit of a line is typically based on the following equation which approximates the real or active power flow on an AC transmission line:

$$\text{Maximum Power Flow (Per Unit or MW)} = |V_S||V_R| / |X_L|$$

where  $V_S$  = Voltage at Sending Terminal in per unit or  $kV_{\phi\phi}$

$V_R$  = Voltage at Receiving Terminal in per unit or  $kV_{\phi\phi}$

$X_L$  = Series reactance of line in per unit or Ohms

The equation above implies that the maximum power flow through an AC transmission line is inversely related to the series reactance of the line, and thus inversely related to the length of the line. Figure 12 illustrates the maximum power transfer limit of various AC EHV lines versus line length:

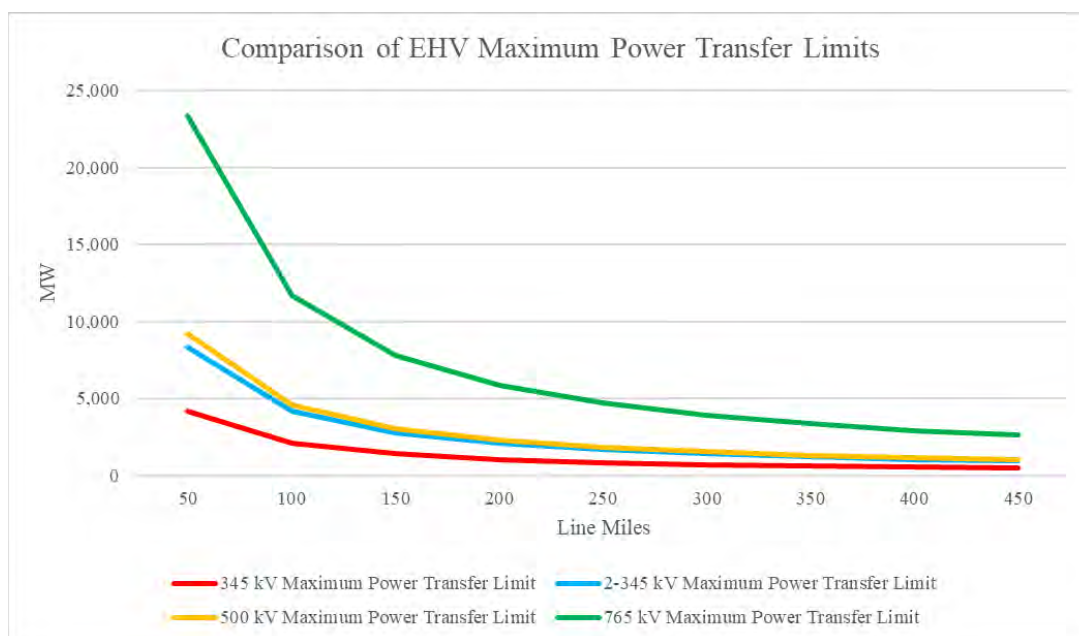


**Figure 122. Comparison of Extra High Voltage Maximum Power Transfer Limits by Line Rated Voltage**  
**NOTE: The graph assumes that the line terminals are infinite buses.**

For HVDC bi-pole lines, the maximum power transfer limit of a line is typically based on the following equation which approximates the power flow on an HVDC transmission line when the terminal HVDC voltages are constrained to +/- 5% of the nominal HVDC voltage level:

$$\text{Maximum Power Flow} = 2 * [1.05V_N][1.05V_N - 0.95V_N] / R_L = 0.21V_N^2 / R_L$$

where  $V_N$  = Nominal HVDC Voltage in per unit or  $kV_{LG}$

$R_L$  = Series resistance of line in per unit or Ohms

The equation above implies that the maximum power flow through an HVDC transmission line is inversely related to the series resistance of the line, and thus inversely related to the length of the line. Figure 13 illustrates the maximum power transfer limit of various hypothetical +/- 640 kV HVDC lines versus line length:



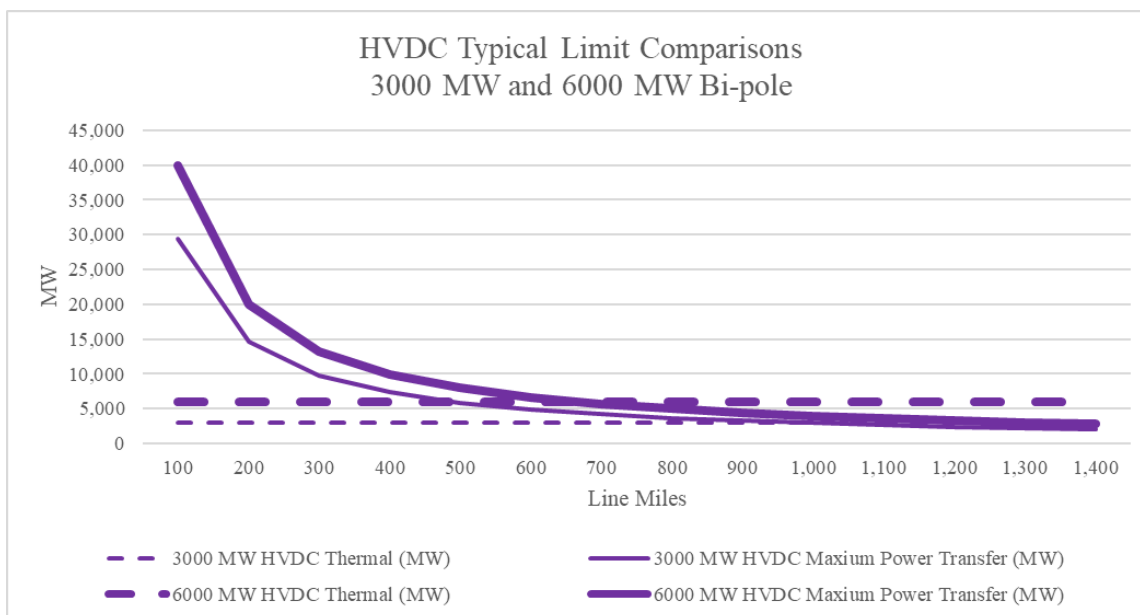


Figure 133. HVDC Typical Limit Comparisons by Line Length

## SAFE LOADING LIMITS

Only AC lines have safe loading limits. A safe loading limit is a risk-based limit and typically represents an inflection point between an operating point of lower reliability risk vs. an operating point of higher reliability risk, hence the name safe loading limit. HVDC lines do not need a safe loading limit because their power flow is precisely controlled which means they can be operated all the way to the maximum power transfer limit without risk of exceeding the maximum power transfer limit or the permissible voltage drop on the HVDC line because of major system disturbances or even minor system perturbations. On the other hand, there should always be a safety margin between the actual operating level and the maximum power transfer limit of an AC line to ensure a major contingency or other sudden change to the operating state of the system does not create an angular or voltage stability issue. Safe loading limits provide such a margin, and like maximum power transfer limits, are inversely related to the line length.

The most common safe loading limit is based on the modified St. Clair curve described in a paper written by three AEP engineers in 1979.<sup>23</sup> In this paper, the safe load limit is designed to limit loading on an EHV AC line to that level which ensures the voltage drop between the sending-end and receiving-end terminals of the line is 5% or less and that loading on the line does not exceed 70% of the steady-state stability limit of the line (often referred to as a 30% stability margin), where the steady-state stability limit for an AC line is equal to the maximum power transfer limit of the AC line. For line lengths of about 200 miles or less, the voltage drop criteria is usually the driving criteria. For line lengths above 200 miles, the steady state stability margin is typically the driving criteria.

<sup>23</sup> Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.



The safe loading limit is calculated as follows:

$$\text{Safe Loading Limit (MW)} = \text{SIL} * \text{SCM}$$

Where SIL = Surge Impedance Loading of the Line (MW)

and SCM = St. Clair Multiplier

The Surge Impedance Loading (SIL) of an AC transmission line is the MW loading level where the reactive power produced by the distributed capacitance of the transmission line exactly balances the reactive power consumed by the distributed inductance of the transmission line, thus the transmission line neither produces nor consumes net reactive power. At loading levels below the SIL, the transmission line produces net reactive power. At loading levels above the SIL, the transmission line consumes net reactive power. The surge impedance loading of a transmission line is a function of the line voltage and per mile distributed capacitance and inductance of the line, but not on the line length.

The St. Clair Multiplier is obtained from the St. Clair curve<sup>23</sup> (Figure 14) and is a function solely of line length. The St. Clair Multiplier is a ratio of the Safe Loading Limit of the line to the Surge Impedance Loading of the line at a specified line length. The Safe Loading limit is the MW loading level that either creates a voltage drop across the line of 5% or greater or encroaches into the 30% steady state stability margin. Figure 15 illustrates the Safe Loading limit vs line length for several AC EHV lines.

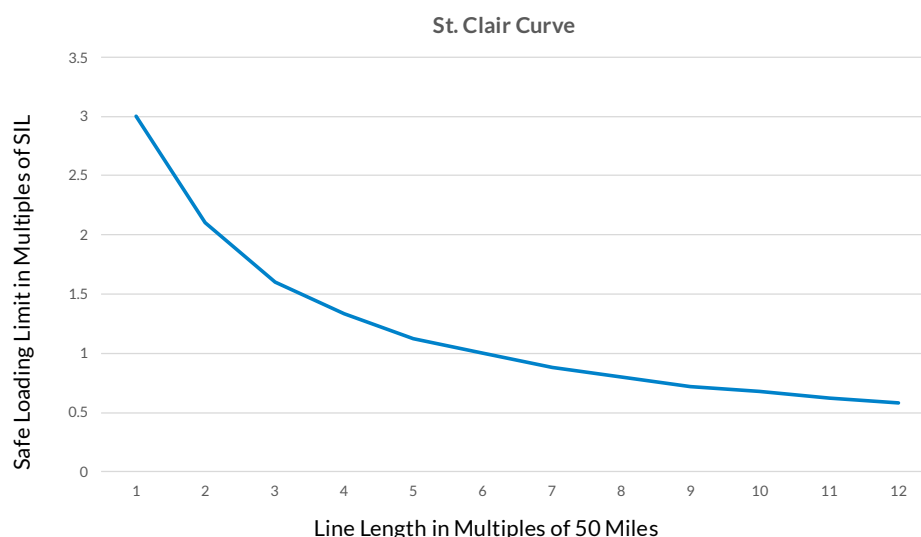


Figure 14: St. Clair Curve, illustrating Safe Loading Limit in Multiples of Surge Impedance Loading for AC EHV lines

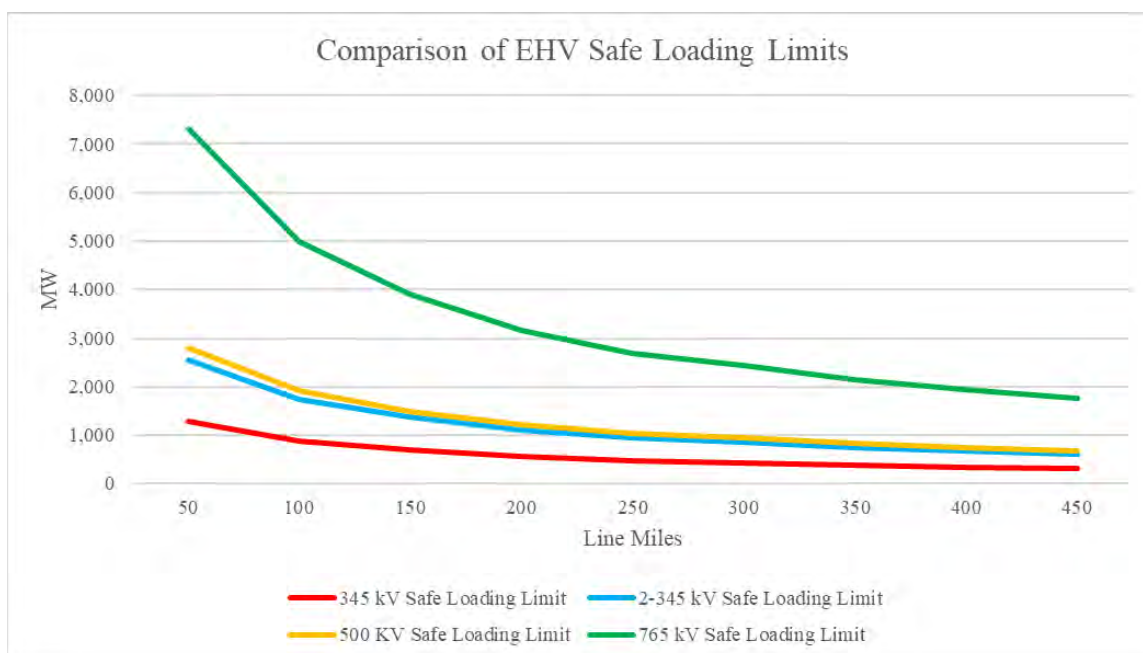


**Figure 15: Safe Loading Limit for Various AC EHV Lines**

*NOTE: The graphs above assume that the line terminals are strong (50 kA fault duty)*

## CROSSOVER POINTS BETWEEN THERMAL LIMIT AND MAXIMUM POWER TRANSFER LIMIT

The graph shown in Figure 13 (HVDC Typical Limit Comparisons by Line Length) illustrates the crossover points where the maximum power transfer limits of the 3000 MW and 6000 MW +/- 640 kV HVDC bi-pole lines fall below their respective thermal ratings. For the 3000 MW HVDC bi-pole line, the crossover point is at 980 Miles. For the 6000 MW HVDC bi-pole line, the crossover point is at 665 miles. Therefore, for line lengths below 650 miles or so, there is typically no reduction of HVDC line capacity with increasing line length. On the other hand, based on the graph above for AC lines (Comparison of EHV Safe Loading Limits), for 765 kV lines, while conductor thermal limits are high at 6,625 MW, the crossover point where the safe loading limit falls below the thermal limit is at a line length of approximately 60 miles, or about 90 miles if 4000 A terminal equipment is used and the 765 kV thermal ratings falls to 5300 MW (which is applicable to most of the 765 kV lines approved in LRTP Tranche 2.1). These crossover points do not represent maximum limitations on line length nor do they represent break-even distances when considering 765 kV versus HVDC but instead represent the line length where the capacity of the 765 kV line begins to reduce as line length increases. For a 345 kV line, the crossover point where the safe loading limit begins to decrease below the thermal limit is less than 50 miles.

## COST-PER-MILE IMPACTS OF LINE LENGTHS FOR AC EHV VS. HVDC LINES

Transmission line capital costs can be broken down into the cost of equipment at the substation terminals and the cost of the line itself. Both EHV AC lines and HVDC lines have certain substation terminal costs. All lines have the cost of AC circuit breakers, breaker disconnect switches, surge arresters, bus conductors, insulators, and similar terminal equipment within the substation footprint. Some EHV AC lines such as 765 kV lines will have shunt reactors connected to the line terminals on the line-side of the



circuit breakers within the substation footprint, thus such equipment is considered part of the terminal equipment costs for the 765 kV line in question. HVDC lines require converters at each terminal, which tend to be very expensive. The costs of all terminal equipment associated with a specific transmission line at the terminating substations can be encapsulated into the term: “zero-mileage” cost. Zero-mileage costs implies that such costs are incurred regardless of the line length and thus are not a function of line length. The “Mileage” costs would then represent the actual cost of the line itself and is a function of line length. The total cost of the line is then the sum of the “zero-mileage” cost and the “mileage” cost. For a typical type of AC or HVDC line, the costs are often expressed in terms of the “zero mileage” cost and the “per mile mileage” costs, and the total cost is then equal to the sum of the zero mileage costs and the product of the per mile cost and the line length in miles.

The costs shown in the table below were estimated in 2023 and represent the zero-mileage and per mile costs of a 765 kV transmission line, 3000 MW +/- 640 HVDC bi-pole line and 6000 MW, +/- 640 kV bi-pole line. The zero-mileage costs of the 765 kV line terminals include two 5000 A circuit breaker positions (one per terminal) and two 300 MVAR shunt reactor banks with dedicated circuit breaker and spare single-phase reactor (one per terminal). The zero-mileage costs of the 3000 MW, +/- 640 kV HVDC bi-pole line includes two 3000 MW, +/- 640 kV VSC HVDC converters (one per terminal) and four 765 kV 3000 A circuit breaker positions (one per pole per converter). The zero-mileage costs of the 6000 MW, +/- 640 kV HVDC bi-pole line includes four 3000 MW, +/- 640 kV VSC HVDC converters (two per terminal) and eight 765 kV, 3000 A circuit breaker positions (one per pole per converter).

The cost per mile of the +/- 640 kV, 3000 MW HVDC line are about half the cost per mile of the 765 kV line option or the +/- 640 kV, 6000 MW option. The cost per mile of the 765 kV line option and the +/- 640 kV, 6000 MW option are about the same. The 765 kV Line has three conductors compared to two conductors for the 6000 MW HVDC line (both lines use 6-795 Aluminum Conductor Steel Reinforced (ACSR) conductor bundles), but the HVDC line requires some additional vertical and horizontal clearances for the conductors, so the per-mile costs of these two options is roughly the same.

| LINE TYPE                                                          | ZERO-MILEAGE COST<br>(TERMINAL COSTS)<br>MILLION \$ | LINE COST PER MILE<br>MILLION \$ / MILE |
|--------------------------------------------------------------------|-----------------------------------------------------|-----------------------------------------|
| 765 KV AC OVERHEAD LINE<br>(6-795 ACSR CONDUCTOR BUNDLE)           | \$ 62.6                                             | \$5.0                                   |
| +/- 640 KV, 3000 MW HVDC BI-POLE<br>(2-1590 ACSR CONDUCTOR BUNDLE) | \$1,658.0                                           | \$2.7                                   |
| +/- 640 KV, 6000 MW HVDC BI-POLE<br>(6-795 ACSR CONDUCTOR BUNDLE)  | \$3,316.0                                           | \$5.0                                   |

Table 2: Comparison of zero-mileage cost and line costs between AC 765KV and HVDC lines

Based on the information in Table 3, the zero-mileage costs of the HVDC options are significantly greater than the zero-mileage costs of the 765 kV options, whereas the per mile costs of the HVDC options are less than or the same as the per mile costs of the 765 kV options.

## LINE LENGTH IS THE KEY CONSIDERATION DRIVING THE CHOICE BETWEEN EHV AC VS. HVDC

For line lengths below 650 miles, the capacity of EHV AC lines tends to diminish with line length when the safe loading limit of the EHV AC lines falls below the thermal limit of the EHV AC line, whereas the capacity of the HVDC lines tends to remain constant with line length at the thermal rating. This is illustrated by Figure 16 below.

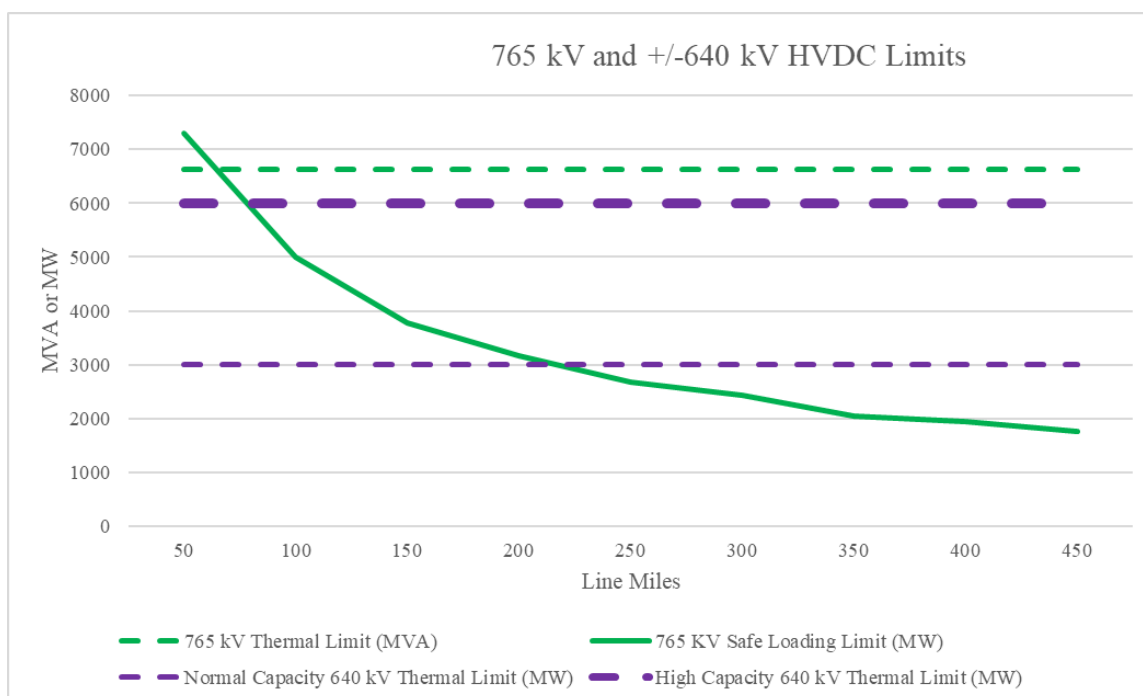


**Figure 16: Comparison of 765 kV and HVDC line capacity and safe loading limits vs line length**

Furthermore, HVDC lines have very high “zero-mileage” costs whereas the zero-mileage cost of an EHV AC lines are much lower. The per-mile cost of an HVDC line tends to be the same or lower than the per-mile cost of an EHV AC line of comparable voltage level. In summary, HVDC lines have very high zero-mileage costs, but the capacity of an HVDC line does not diminish with line length. Furthermore, the per-mile costs of HVDC lines tend to be less than or equal to the per-mile costs of EHV AC lines. Having said this, when EHV AC lines are compared with HVDC lines on a cost per MW-mile basis, the EHV AC lines are more economical below a certain line length and the HVDC lines are more economical above a certain line length. Figure 17 was prepared in 2023 based on the 2023 cost estimates in Table 3 and the 765 kV and +/- 640 kV HVDC line limits in Figure 16. It is important to note that the actual breakeven mileage can vary significantly based on changing assumptions, such as voltage level, type of conductor used, type of converter used, and other such design criteria, so in general, a single breakeven point should be avoided, and a breakeven range should be considered instead. The breakeven range in Figure 17 is 250 to 400 miles. Above 400 miles, HVDC tends to be more economical whereas below 250 miles 765 kV tends to be more economical. For line lengths above 250 miles and below 400 miles, the choice of 765 kV vs. HVDC should be analyzed in more detail.

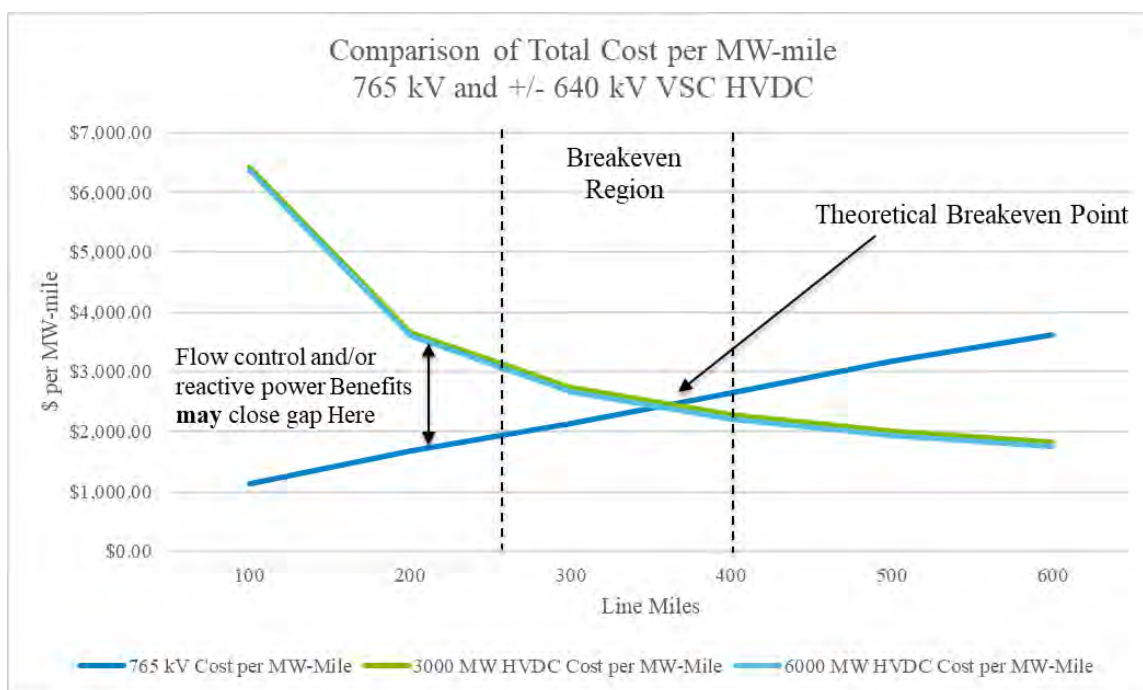


Figure 17: Comparison of Total Cost per MW-mile: 765 kV and +/- 640 kV VSC HVDC

## THE BENEFITS OF HVDC FLOW CONTROL VERSUS THE BENEFITS OF AC NATURAL FLOW RESPONSE

There are potential flow control benefits provided by HVDC lines under certain scenarios and conditions and potential natural flow response benefits associated with EHV AC lines under other scenarios and conditions. It is important to discuss the pros and cons of flow control versus natural flow response and how this consideration could impact the choice between an EHV AC line and an HVDC line.

Regarding AC lines, it is well known that the flows on AC lines are a natural function of the following:

- The topology of the AC transmission system and the characteristics of AC transmission facilities (e.g., line impedances and shunt susceptance, etc.).
- The location and magnitude of generation, load, and other shunts (e.g., capacitor banks, etc.).
- The status of generation and transmission facilities (forced outages, planned outages, unit commitment, switched shunts, tap changers, etc.)

It is important to note that there are devices that can be used on the AC transmission system to influence transmission flows, but these techniques simply alter the topology and/or characteristics of the AC system and do not precisely control the flows on AC transmission facilities. The more common methods of controlling flows on the AC system are:

- Switchable series reactors or capacitors (very limited control options – in or out).
- Phase angle regulator transformers (rough control at best – not continuous).



- Static synchronous series compensators (more precise control, but not as precise as HVDC flow control – often incorporated into “smart wire” technology).

Unlike flows on AC transmission facilities, the flows on HVDC lines are precisely scheduled or controlled. Common methods of scheduling or controlling flows on HVDC lines include the following:

- Manually entered schedules.
- Automatic controls to follow the output of a source generation resource.
- Automatic controls to emulate an AC transmission line natural response (based on voltage phase angles at the AC terminals of the HVDC line and a simulated proxy impedance).
- Potentially dispatching HVDC flows in real-time via Security Constrained Economic Dispatch to co-optimize resource outputs with HVDC schedules.

A primary distinction between the flows on AC transmission lines versus HVDC transmission lines is that AC transmission line flows are natural and HVDC transmission flows are precisely scheduled. The response of AC transmission flows to changes in generation output, load, and system topology is natural and nearly instantaneous. Natural and nearly instantaneous transmission flow response can be a good thing or a bad thing. The response of HVDC transmission flows to changes in generation output, load, and system topology requires manual intervention or control action, and while it can be fast, it is not instantaneous. The requirement of flows on HVDC transmission lines to be controlled or scheduled can be a good thing or a bad thing.

The ability to control flows on HVDC lines can provide several benefits. Because HVDC flows are scheduled and not dependent on the transmission system topology and characteristics, the entire capacity of an HVDC line can be used whenever needed and there is no risk that a major system disturbance or minor system perturbation will cause the HVDC line to overload or exceed its maximum power transfer limit. This allows an HVDC line to act like a “vacuum cleaner”, absorbing flow off heavily loaded parallel AC lines up to the capacity of the HVDC line without a risk that the HVDC bi-pole could become overloaded following a major contingency or minor system change. This requires of course that the underlying AC system be strong enough to withstand a monopole or bi-pole trip of the HVDC facility.

Another potential benefit of the ability to control flows on HVDC lines is to co-optimize the HVDC schedules with resource outputs to further minimize AC transmission congestion and overall transmission system losses, which of course will further minimize overall production costs. The co-optimization of HVDC schedules with resource outputs can be accomplished via modifications to the day-ahead market security constrained unit commitment and security constrained economic dispatch algorithms, the security constrained unit commitment algorithms used in the various reliability assessment commitment processes, and the security constrained economic dispatch algorithm used to clear the real-time market. MISO is presently pursuing the capability to dispatch and co-optimize HVDC lines. More information is provided in the markets section of this white paper on MISO work to date and future MISO plans.

While the ability to control flows on the HVDC lines can provide several benefits, the lack of natural flow response on the HVDC lines can be problematic under a future where generation dispatch and load is much more volatile. For example, fast morning ramp-down of wind in one region coupled with fast





morning ramp-up of solar in another region (or vice versa) can cause very fast and significant changes to flow patterns on the AC system. Fast or near instantaneous ramping of large data centers can be equally problematic. If HVDC schedules do not quickly follow these fast and significant changes in resource dispatch and load, the result can be substantial congestion and/or reliability risk on the underlying AC transmission system. In the past, there are situations where the flow on a 765 kV line changed from 3000 MW in one direction to 3000 MW in the opposite direction within a 12-hour period. These changes were not driven by major outages of generation or transmission facilities but instead changes in generation dispatch and load. In the future, as the penetration of renewable generation continues to increase, resource dispatch becomes more volatile, large data center loads become a much higher percentage of the total system load, and the overall volatility of load becomes much greater, the magnitude and speed of AC line flow changes could increase significantly. These volatile flow changes are not an issue with AC transmission since the flow response of AC transmission is natural and adjusts as generation output and load levels adjust, thus volatile changes in generation dispatch and load (i.e., major ramping) is followed perfectly by AC lines. For HVDC, it is necessary to stay on top of significant and fast changes in generation and load to ensure HVDC schedules follow these generation and load changes, otherwise the flow control requirement of HVDC lines could compound the issues.

Regarding flow control, VSC HVDC equipment is capable of very fast response and bi-directional response, so there are two strategies to mitigate (but not totally eliminate) the lack of natural response by VSC-based HVDC lines. First, it is possible to mitigate the requirement for flow control and the lack of natural flow response on HVDC lines by installing a control system that simulates the natural response of an AC line. Such a control system would simulate a predetermined proxy AC line impedance and then continuously control flows on the HVDC line based on the phase angle difference between the bus voltages at the sending and receiving AC terminals of the HVDC line. For long distance lines where the capacity of an AC line is significantly derated based on the length of the line, this is a promising strategy. For shorter and intermediate distances where the capacity of the AC line is not significantly derated, it would likely be best to simply install an AC line instead and save the cost of the HVDC converter equipment that would otherwise be required.

A more promising mitigation strategy being pursued by MISO is to allow the real-time market security constrained economic dispatch algorithm that clears the real-time market to also co-optimize HVDC schedules with resource outputs every five (5) minutes. This does not provide instantaneous natural response, but does allow for automatic control of HVDC schedules to occur every five (5) minutes based on data that is ten (10) to fifteen (15) minutes old (i.e., the real-time dispatch is updated every five (5) minutes and initiated about ten (10) minutes ahead of the targeted dispatch time point in the real-time market using inputs that are up to five (5) minutes old). In addition to mitigating congestion and minimizing losses in general, dispatchable HVDC can also mitigate (but not totally eliminate) the lack of natural response on HVDC lines during times when generation dispatch and load is volatile. As stated before, more information is available elsewhere in this whitepaper on the concept of dispatchable HVDC and the work that is currently underway to research and develop dispatchable HVDC at MISO.

In summary, the flow control capabilities of HVDC lines can provide substantial benefits, but the lack of natural flow response in HVDC lines can also cause substantial issues. While flow control can be a benefit

for HVDC, it can also cause issues, thus the assessment of net flow control benefits on any HVDC line must be studied on a case-by-case basis.

## **CONSIDERATION OF ANCILLARY BENEFITS IN PLANNING INTRA-REGIONAL HVDC LINES**

The HVDC industry has been articulating several ancillary benefits provided by VSC HVDC technology and has claimed that these ancillary benefits must always be considered in making planning decisions regarding the pursuit of VSC HVDC transmission solutions versus EHV AC transmission solutions. In some cases, many of these ancillary benefits are valid. In some cases, these ancillary benefits are only realized in certain situations. Lastly, some of the touted ancillary benefits are either not valid or at best are dependent on several variables and thus must be considered on a case-by-case basis. Listed below are the most common ancillary benefits and a brief discussion on situations where there may be valid benefits that deserve due consideration:

### **Dynamic Reactive Power and Voltage Control**

While LCC HVDC technology consumes substantial amounts of reactive power and does not allow for voltage control, VSC HVDC technology does not need to consume reactive power and can inject or absorb reactive power independently of real or active power schedules at each AC terminal. The VSC converter is thus a source of dynamic reactive power and voltage control and basically acts as a STATCOM at each AC terminal of the HVDC line. This is a valid benefit and could be substantial for contributing to dynamic voltage recovery.

The assessment of the dynamic reactive power benefits must consider other potential sources for dynamic reactive power and whether those sources would be in place regardless. One potential resource is synchronous machines. To the extent there are conventional resources with synchronous generators in the vicinity of the AC terminals of an HVDC line, such resources may be able to provide the dynamic reactive power needs of the system as well in this area, thus the dynamic reactive power benefits provided by the HVDC VSC converters, while valid, are also unneeded since there is no deficit in dynamic reactive power supply in the area. These conventional generation resources could represent older legacy generating units or newly installed generation resources such as combined cycle gas generation resources or small modular reactor resources that continue to use synchronous machines. It is important to note that synchronous machines are not always on-line, and to the extent a resource that drives a synchronous generator is off for economy or other reasons, such resource will not be able to supply dynamic reactive power except for rare situations where the unit is set up to operate as a synchronous condenser when the prime mover is off-line.

It is also important to note that both the grid following and grid forming inverters that enable the interconnection of renewable energy resources such as wind and solar, as well as energy storage resources such as electric batteries, are also generally capable of providing dynamic reactive power and voltage control. With respect to grid following inverters, which are the most common inverters in place today for wind and solar resource, these inverters act as current sources and can control the phase angles of the currents they inject into the system with respect to the phase angles of the AC voltages at their terminals to dynamically inject or absorb reactive power within the limits of the inverter. MISO requires IBRs to provide dynamic reactive current injection during voltage ride-through events. Grid forming inverters act as voltage sources capable of generating the inverter's internal output voltage magnitude,



phase angles, and frequency. These types of inverters behave similarly to synchronous machines, except for typically having a lower fault current rating. Grid Forming Inverters are essentially equivalent to STATCOMs, but unlike STATCOMs, are not in place to provide dynamic reactive power, but instead are in place to facilitate the interconnection of renewable energy resources and battery energy storage systems. In any event, to the extent dynamic reactive power and voltage control is available from grid following and/or grid forming inverters across the system installed for the purpose of interconnecting generation resources, the dynamic reactive power capabilities of these inverters are ancillary benefits that can be used to meet dynamic reactive power benefits, thus diminishing or eliminating the actual dynamic reactive power ancillary benefits from VSC HVDC converters in the area in most cases.

Three additional points need to be made regarding the use of grid following and grid forming inverters as sources of dynamic reactive power. First, some in the industry have expressed concern that the dynamic reactive power capabilities of inverters are less than the dynamic reactive power capabilities of traditional synchronous machines, and the displacement of synchronous machine based resources with inverters could create a deficit in dynamic reactive power needs that could be met or partially met by the VSC converters associated with HVDC lines, thus the dynamic reactive power ancillary benefits of VSC HVDC lines should always be considered. The reactive power capabilities of synchronous machines and inverters are based on the specific capability curves of the machine or device and vary with the real power output of the resource. However, the rated power factors of the machine can be used to estimate relative reactive power capabilities of a synchronous machine versus an inverter. For example, a typical rated power factor for a synchronous machine might be 85%, which means the reactive power injection capabilities of a 100 MW synchronous machine resource operating at full output would be approximately 62 MVAR. A typical rated power factor for an inverter might be 95%, which means the reactive power injection capabilities of a 100 MW inverter-based resource operating at full output would be approximately 33 MVAR or nearly half the reactive capability of a synchronous machine resource of the same size. Based on this, one might believe that inverters will not be capable of providing the same level of reactive power as the synchronous machines they are displacing. However, it is important to note that the aggregate nameplate capability of installed inverters will be much greater than the nameplate capacity of the synchronous generators they are displacing. The reason for this is that the capacity credit for conventional resources driving synchronous machines is much higher than the capacity credit of the inverter-based resources, thus the aggregate nameplate capacity of installed renewable resources and associated inverters will be much higher than the aggregate nameplate capacity of the synchronous machine based resources being displaced. This means that the lower reactive power capabilities of inverters on a “per MVA” capacity basis will be applied to a much higher MVA capacity base, thus there may not be a deficit of resource-based dynamic reactive power capability in the future. The other important point to remember is that inverters, like VSC HVDC converters, allow for the independent control of real and reactive power, and thus can be on-line providing dynamic reactive power at all times, even when there is zero real or active power being injected by the associated renewable resource or injected or withdrawn by the associated battery energy storage system. This provides an advantage that even the conventional synchronous machine fleet did not provide, and that is 24/7 dynamic reactive power capability even when the resources prime energy source is unavailable. This eliminates any dynamic reactive power concerns that might be associated with inverter-based resources that have low availability because they are associated with low-capacity factor resources. Finally, it is important to note



that when renewable resources with many inverters are the source of dynamic reactive power in an area, such resources will be distributed across the area. The assignment of dynamic reactive power responsibilities to a greater number of smaller sized inverters that are distributed across an area versus to a fewer number of larger sized HVDC VSC inverters that are not as distributed has benefits as well in terms of distributing voltage support and avoiding larger dynamic power generation contingencies.

In summary, while VSC HVDC converters can provide a substantial amount of dynamic reactive power capability, this capability is likely to be available by future resources whether they be synchronous machine resources or inverter-based resources, thus the actual net benefit of the VSC HVDC converter capabilities to provide dynamic reactive power is negated in many cases.

## **GRID FORMING CAPABILITIES**

Unlike LCC HVDC converters, which are similar to grid following inverters, VSC HVDC converters can generate AC grid voltage waveforms, and this is a potential benefit to the system. Before electric power can be generated or transported, there must be AC voltages present in the system since AC voltages are necessary prerequisites for the generation and delivery of electrical energy. Historically capabilities such as inertia and voltage waveform formation have been taken for granted since these capabilities are inherent capabilities of a synchronous machine. However, the most common inverter on the system today is the grid following inverters, and such inverters have no grid forming capabilities. This is not an issue when the percentage of the resource fleet made up of grid following inverters is small, but as more of the resource capacity uses grid following inverters, issues may be introduced regarding system stability, lack of voltage control and lack of black start capability.

As discussed earlier, an assessment of the benefit to the grid-forming capabilities of VSC HVDC converters must also consider if these benefits are available from other sources. Both synchronous machines and grid forming inverters can form voltage waveforms, and to the extent sufficient quantities of such resources exist in the vicinity of the AC terminals of a VSC HVDC line in the future, the overall grid forming benefits of VSC HVDC converters could be significantly diminished. This is based on the same argument made for dynamic reactive power. To the extent synchronous machine generation resources make up a portion of the future generation fleet (e.g., combined cycle gas resources, small modular reactors, etc.), some of the retiring synchronous machines could be replaced with new synchronous machines. Furthermore, if a shift begins to occur toward grid forming inverters and away from grid following resources for inverter-based resource interconnections, the potential grid forming benefits of VSC HVDC converters could be significantly diminished since such capabilities are already provided for by grid forming inverters and not needed by VSC HVDC converters.

It is important to note that there is a small but very specific benefit provided by VSC HVDC lines tied to grid forming capabilities that is not available for LCC HVDC lines. A VSC HVDC line installed between two asynchronous areas will facilitate black starting one asynchronous area from the other area. While there are likely other local alternatives for black starting a dead area using local grid forming resources, an LCC HVDC line between the two asynchronous areas would not have the capability to black start one area from the other since LCC HVDC lines require voltage to be present at each AC terminal, but unlike VSC HVDC converters, cannot generate those voltage waveforms.

## **Voltage and Angular Stability Benefits**

The key steady state voltage and angular stability benefits in steady state are discussed above, with line length as a key consideration in determining if a new line should be an EHV AC line or HVDC line. With respect to an EHV AC line, the longer the line, the larger the steady state voltage drop, the lower the maximum power transfer limit and the lower the safe loading limit. For longer EHV AC lines, there is always greater risk of low voltage issues, voltage stability issues, and/or angular stability issues. Line length is not so much an ancillary benefit as it is a key consideration to the choice between EHV AC versus HVDC, as was discussed above in detail.

It is important to note that there is a specific ancillary benefit of VSC HVDC lines related to supporting angular stability via special control actions known as fast power modulation. Through rapid power flow control, VSC HVDC lines can rapidly increase or decrease power transfer, responding within milliseconds to changes in system conditions. This type of control can be used to dampen inter-area oscillations caused by large-scale swings in power flow between regions, which helps stabilize the system during and after faults. The VSC HVDC line with fast power modulation acts as a shock absorber in the event of disturbances (e.g., sudden loss of generation or load). The HVDC link can temporarily absorb or inject power, stabilizing frequency and angular separation between generators, thus preventing loss of synchronism which could potentially result in a wide area blackout.

## **Flow Control Benefits**

One of the major ancillary benefits associated with HVDC lines is the flow control capabilities of HVDC in general and VSC HVDC in particular. MISO sees this more as a key consideration, which in addition to line length, is the primary driver for choosing either an HVDC solution or an EHV AC solution for a specific set of issues. As such, flow control was discussed earlier in the whitepaper as were the potential tradeoffs between the benefits of having the flow control capabilities of an HVDC line versus the issues associated with the lack of natural flow response capability by HVDC lines as discussed above.

## **Transfer Loss Reduction**

Another ancillary benefit claimed for HVDC lines is lower transfer losses associated with HVDC lines in general. However, MISO has found this is not necessarily the case. It is true that higher voltage levels tend to result in much lower load losses in general, but that conclusion is not driven by whether the line is an HVDC line or EHV AC line. There are certain factors that help reduce losses in HVDC lines compared to AC lines, most notably the fact that DC line resistances are lower than AC lines resistances for the same conductor due to skin effect and the fact that for a given voltage level, the corona losses associated with an HVDC line may be lower than the corona losses associated with a comparable AC line. It has been said that an HVDC line contains only two conductors compared to three conductors for an AC line, thus the losses on the AC line for the same size conductors (neglecting the difference between the AC and DC resistance) would be 150% of the losses of the HVDC line, everything else equal (losses associated with three conductors versus two conductors). What this simple analysis fails to consider is the converter losses. Converter losses for VSC HVDC lines are often estimated at 0.7% per terminal or 1.4% for the total zero-mileage load losses. There are no zero-mileage load losses associated with AC lines, and when these losses are factored into the total transfer losses of an HVDC line, particularly for lines with lengths of 300 miles or less, there is no evidence to suggest that HVDC lines have lower losses than comparable

EHV AC lines when converter losses are considered. For extremely long lines (above 400 miles) where the converter losses become a smaller percentage of total losses, the total HVDC losses could be less, but other factors would tend to favor HVDC for these longer lines as discussed above. Table 4 below compares the loss levels for various VSC HVDC and EHV AC choices to further illustrate these points.

| Type                  | kV  | Length | MW Flow | Current (A) | R ( $\Omega$ per Mile) | Line Losses (MW) | Converter Losses (MW) | Line Losses (%) | Converter Losses (%) | Total Losses (%) |
|-----------------------|-----|--------|---------|-------------|------------------------|------------------|-----------------------|-----------------|----------------------|------------------|
| HVDC Bi-pole          | 600 | 225    | 3000    | 2500        | 0.019008               | 53.5             | 42.0                  | 1.78%           | 1.40%                | 3.182%           |
| EHV AC Single circuit | 765 | 225    | 3000    | 2264        | 0.023144               | 80.1             | 0.0                   | 2.67%           | 0.00%                | 2.669%           |
| HVDC Bi-pole          | 500 | 325    | 2000    | 2000        | 0.028512               | 74.1             | 28.0                  | 3.71%           | 1.40%                | 5.107%           |
| EHV AC Single circuit | 765 | 325    | 2000    | 1509        | 0.023144               | 51.4             | 0.0                   | 2.57%           | 0.00%                | 2.571%           |
| HVDC Bi-pole          | 500 | 100    | 2000    | 2000        | 0.028512               | 22.8             | 28.0                  | 1.14%           | 1.40%                | 2.540%           |
| EHV AC Single circuit | 765 | 100    | 2000    | 1509        | 0.023144               | 15.8             | 0.0                   | 0.79%           | 0.00%                | 0.791%           |
| EHV AC Single circuit | 500 | 100    | 2000    | 2309        | 0.040128               | 64.2             | 0.0                   | 3.21%           | 0.00%                | 3.210%           |
| EHV AC Double-circuit | 345 | 100    | 2000    | 3347        | 0.018348               | 61.7             | 0.0                   | 3.08%           | 0.00%                | 3.083%           |

Table 3: Comparison of Line Losses across VSC HVDC and EHV AC Transmission Options

## 7 Future Work

This section summarizes the recommendations from the impact assessment, organized by priority. The recommendations are not time-bound but do have three levels of priority, as is explained below. Recommendations beginning with:

- **“MISO should”** are high priority relative to other HVDC recommendations. These actions relate to a reliability concern or stakeholder priority.
- **“As HVDC penetration increases, MISO should”** are medium priority relative to other HVDC recommendations, with the need linked to additional deployment of HVDC facilities in MISO. These actions can wait until planned HVDC facilities proceed further in their development.
- **“MISO could”** are lower priority. These are issues and ideas that have arisen in MISO’s assessment that might have value but are not necessarily pressing.

|        | Workstream             | Recommendation Title                                                                         | Recommendation                                                                                                                                                                                                                                                                                 |
|--------|------------------------|----------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| High   | Merchant HVDC          | <b>Improvements to MISO Attachment GGG process</b>                                           | MISO is making Tariff language changes to Attachment GGG, updating the MISO MHVDC interconnection process, and making Limited Operation clarifications for interim periods on qualified MHVDC projects and will continue to engage with stakeholders on these issues through the IPWG and PAC. |
|        | Merchant HVDC          | <b>MHVDC Business Practice Manual</b>                                                        | MISO is creating an MHVDC BPM focusing on MHVDC application, application modification, application withdrawal, study scope, process timelines, study requirements, affected system studies, and Pre-TCA considerations.                                                                        |
|        | Reliability Operations | <b>Contingency management procedures for HVDC facilities</b>                                 | MISO should continue to update the MSSC and contingency reserve requirements as system conditions evolve to ensure reliability.                                                                                                                                                                |
|        | Resource Adequacy      | <b>Resource Adequacy treatment of External Resources, including those delivered via HVDC</b> | MISO should collaborate with stakeholders to clarify how External Resources, including those delivered by HVDC-enabled firm transmission, are modeled and participate under MISO’s current Resource Adequacy construct.                                                                        |
|        | Resource Adequacy      | <b>Accreditation enhancements for External Resources</b>                                     | MISO should evaluate updating the accreditation of external resources to improve alignment with the Direct Loss of Load Resource Adequacy (RA) Hours approach.                                                                                                                                 |
| Medium | Markets                | <b>Interchange and market-to-market congestion management processes</b>                      | As penetration of HVDC increases, MISO should evaluate approaches to integrate HVDC into interchange and market-to-market congestion management processes and discuss these approaches with our neighbors.                                                                                     |
|        | Markets                | <b>Intra-regional HVDC in market and operations processes</b>                                | As HVDC penetration increases, MISO should evaluate these potential approaches to partially integrate intra-regional HVDC into market and operations practices.                                                                                                                                |
|        | Reliability Operations | <b>Contingency management procedures for HVDC facilities</b>                                 | As HVDC penetration increases, MISO should assess the risk of contingency reserve cost increases and evaluate opportunities to mitigate these increases through reserve sharing agreements or alternative cost allocation processes.                                                           |
|        | Reliability Operations | <b>HVDC impacts on system stability risk</b>                                                 | As penetration of HVDC facilities increases, MISO should conduct, or coordinate with other entities to conduct frequency, voltage, and rotor angle stability risk assessments related to the loss of the HVDC facility, as well as assess converter-driven stability risks.                    |
|        | Reliability Operations | <b>Outage coordination and operator visibility for HVDC facilities</b>                       | As penetration of HVDC facilities increases, MISO should evaluate more granular representation of de-rates during outage coordination processes and enhanced representation of HVDC facilities in the energy management system and consider other enhancements to improve operator visibility. |
|        | Expansion Planning     | <b>Test modeling and performance of PROMOD HVDC simulation capabilities</b>                  | As a medium priority, MISO should test the modeling and performance of the dispatchable and co-optimized HVDC capability of PROMOD to ensure it is an acceptable proxy for the dispatchable HVDC solution to be developed by the market side.                                                  |



| Workstream |                    | Recommendation Title                                                     | Recommendation                                                                                                                                                                                              |
|------------|--------------------|--------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Low        | Markets            | <b>Intra-regional HVDC in market and operations processes</b>            | MISO could continue to research open questions related to full integration.                                                                                                                                 |
|            | Markets            | <b>HVDC in congestion hedging processes</b>                              | MISO could assess the risk of FTR underfunding and possibility of missed hedging opportunities and evaluate potential process enhancements to better align FTR auctions with evolving operational practice. |
|            | Resource Adequacy  | <b>Representation of transmission in Resource Adequacy risk modeling</b> | MISO could evaluate methods for incorporating transmission lines, including HVDC, into Resource Adequacy risk modeling.                                                                                     |
|            | Expansion Planning | <b>Investigate feasibility of AC line emulation controls</b>             | MISO could further investigate the feasibility of AC line emulation controls as an option for future regional HVDC lines where AC response is desired, but the line length is too long for an AC line.      |

**Table 5: Summary of recommendations based upon HVDC Impact Assessment, in order of priority with corresponding work stream identified**

# 8 Acronyms and Glossary

## ACRONYMS

|                                                      |                                                                     |                                                                                                     |                                                                                              |
|------------------------------------------------------|---------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------|
| <b>AC:</b> Alternating Current                       | <b>FRAP:</b> Fixed Resource Adequacy Plan                           | <b>MSC:</b> Market Sub-Committee                                                                    | <b>RTO:</b> Regional Transmission Operator                                                   |
| <b>ACE:</b> Area Control Error                       | <b>FTR:</b> Financial Transmission Right(s)                         | <b>MSSC:</b> Most Severe Single Contingency                                                         | <b>SAC:</b> Seasonal Accredited Capacity                                                     |
| <b>ACSR:</b> Aluminum Conductor Steel Reinforced     | <b>GADS:</b> Generating Availability Data System                    | <b>MTEP:</b> MISO Transmission Expansion Plan                                                       | <b>SCADA:</b> Supervisory Control and Data Acquisition                                       |
| <b>AEMO:</b> Australia Energy Market Operator        | <b>GFM:</b> Grid Forming (Inverter)                                 | <b>MVAR:</b> Megavolt-Ampere Reactive                                                               | <b>SCED:</b> Security Constrained Economic Dispatch                                          |
| <b>AFC:</b> Available Flowgate Capability            | <b>GSF:</b> Generation Shift Factor                                 | <b>MW:</b> MegaWatt                                                                                 | <b>SCM:</b> St. Clair Multiplier                                                             |
| <b>AGC:</b> Automatic Generation Control             | <b>GVTC:</b> Generator Verification Test Capacity                   | <b>NEM:</b> (Australia's) National Electricity Market                                               | <b>SCR:</b> Short Circuit Ratio                                                              |
| <b>ARS:</b> Automated Reserve Sharing                | <b>HVDC:</b> High Voltage Direct Current                            | <b>NERC:</b> North American Reliability Corporation                                                 | <b>SCUC:</b> Security Constrained Unit Commitment                                            |
| <b>BA:</b> Balancing Authority                       | <b>Hz:</b> Hertz                                                    | <b>NERC BAL:</b> Resource and Demand Balancing (BAL) body of standards                              | <b>SDAC:</b> Single Day-Ahead Coupling                                                       |
| <b>BAA:</b> Balancing Authority Area                 | <b>IBR:</b> Inverter-Based Resource                                 | <b>NERC TPL:</b> Transmission Planning body of standards                                            | <b>SDX:</b> System Data Exchange                                                             |
| <b>BPA:</b> Bonneville Power Administration          | <b>ICCP:</b> Inter-control Center Communication Protocol            | <b>NLR:</b> National Laboratory of The Rockies                                                      | <b>SE:</b> State Estimator                                                                   |
| <b>BPM:</b> Business Practice Manual- (MISO)         | <b>IDC:</b> Interchange Distribution Calculator                     | <b>NSI:</b> Net Scheduled Imports                                                                   | <b>SERVIM:</b> Strategic Energy Risk Valuation Model (Resource Adequacy Software)            |
| <b>CA:</b> Contingency Analysis                      | <b>IEEE:</b> Institute of Electrical and Electronics Engineers      | <b>NYISO:</b> New York Independent System Operator                                                  | <b>SIDC:</b> Single Intraday Coupling                                                        |
| <b>CAISO:</b> California Independent System Operator | <b>IESO:</b> Independent Electricity System Operator                | <b>OMS:</b> Organization of MISO States                                                             | <b>SIL:</b> Surge Impedance Loading of the Line (MW)                                         |
| <b>CB:</b> Circuit Breaker                           | <b>IGBT:</b> Insulated Gate Bipolar Transistor                      | <b>ONS:</b> National Electric System Operator of the Brazilian National Interconnected System (SIN) | <b>SLG:</b> Single Line to Ground                                                            |
| <b>CIL:</b> Capacity Import Limit                    | <b>IMM:</b> Independent Market Monitor                              | <b>PAR:</b> Phase Angle Regulator                                                                   | <b>SPP:</b> Southwest Power Pool                                                             |
| <b>CEP:</b> Capacity Export Limit                    | <b>INELFE:</b> Electrical Interconnection Spain – France            | <b>PDCI:</b> Pacific Direct Current Intertie                                                        | <b>SPS:</b> Special Protection Systems                                                       |
| <b>CP:</b> Commercial Pricing (Node)                 | <b>ISA:</b> Interconnection Service Agreement (NYISO Merchant HVDC) | <b>PJM:</b> Pennsylvania-New Jersey-Maryland Interconnection                                        | <b>SREA:</b> Southern Renewable Energy Association                                           |
| <b>CPNY:</b> Clean Path New York (Project)           | <b>ISBA:</b> Integral Square Bus Angle                              | <b>PMU:</b> Phasor Measurement Unit                                                                 | <b>STATCOM:</b> Static Synchronous Compensator                                               |
| <b>CROW:</b> Control Room Operations Window          | <b>ISO:</b> Independent System Operator                             | <b>POI:</b> Point of Interconnection                                                                | <b>SSCTI:</b> Sub-Synchronous Control Torsional Interactions                                 |
| <b>CRR:</b> Congestion Revenue Rights (CAISO)        | <b>ISONE:</b> Independent System Operator New England               | <b>PPA:</b> Power Purchase Agreement                                                                | <b>TCA:</b> Transmission Control Agreement (CAISO); Transmission Connection Agreement (MISO) |
| <b>CRSG:</b> Contingency Reserve Sharing Group       | <b>JOA:</b> Joint Operating Agreement                               | <b>PRA:</b> Planning Reserve Auction                                                                | <b>TCC:</b> Transmission Congestion Contract (NYISO)                                         |
| <b>CTS:</b> Coordinated Transaction Scheduling       | <b>kV:</b> Kilovolt                                                 | <b>PRM:</b> Planning Reserve Margin                                                                 | <b>TCR:</b> Transmission Congestion Rights (SPP); Transmission Connection Request (MISO)     |
| <b>DA:</b> Day-Ahead                                 | <b>LCC:</b> Line Commutated Converter                               | <b>PRMR:</b> Planning Reserve Margin Requirements                                                   | <b>TDF:</b> Transfer Distribution Factor                                                     |
| <b>DC:</b> Direct Current                            | <b>LCR:</b> Local Clearing Requirements                             | <b>PSCAD:</b> Power Systems Computer-Aided Design (Manitoba Hydro)                                  | <b>TPL:</b> Technology Performance Level                                                     |



|                                                                                   |                                                        |                                                                            |                                                  |
|-----------------------------------------------------------------------------------|--------------------------------------------------------|----------------------------------------------------------------------------|--------------------------------------------------|
| <b>DCR:</b> Direct Current Reactor                                                |                                                        | <b>PWL:</b> Piecewise Linear                                               | <b>TLR:</b> Transmission Loading Relief          |
| <b>DCCB:</b> Direct Current Circuit Breaker                                       | <b>LMP:</b> Locational Marginal Price                  | <b>PWM:</b> Pulse Width Modulation                                         | <b>TSAT:</b> Transient Security Assessment Tool  |
| <b>DLOL:</b> Direct Loss of Load                                                  | <b>LMR:</b> Load Modifying Resources                   | <b>RA:</b> Resource Adequacy                                               | <b>TSO:</b> Transmission System Operator         |
| <b>DMR:</b> Dedicated Metallic Return                                             | <b>LOLE:</b> Loss of Load Expectation                  | <b>RAR:</b> Resource Adequacy Requirements                                 | <b>UFLS:</b> Under Frequency Load Shedding       |
| <b>EHV:</b> Extra High Voltage                                                    | <b>LRTP:</b> Long-Range Transmission Plan              | <b>RAS:</b> Remedial Action Scheme                                         | <b>VSC:</b> Voltage Source Converter             |
| <b>EI:</b> Eastern Interconnection                                                | <b>LSE:</b> Load Serving Entity                        | <b>RASC:</b> Resource Adequacy Sub-Committee                               | <b>WADC:</b> Wide Area Damping Controller        |
| <b>EMS:</b> Energy Management System                                              | <b>M2M:</b> Market to Market                           | <b>RBDC:</b> Reliability Based Demand Curve                                | <b>WAMS:</b> Wide Area Monitoring System         |
| <b>EMT:</b> Electromagnetic Transient                                             | <b>MHEB:</b> Manitoba Hydro-Electric Board             | <b>RIIA:</b> <a href="#">Renewable Integration and Impact Study</a> (MISO) | <b>WECC:</b> Western Energy Coordinating Council |
| <b>ENTSO-E:</b> European Network of Transmission System Operators for Electricity | <b>MISO:</b> Mid-Continent Independent System Operator | <b>RoCoF:</b> Rate of Change of Frequency                                  | <b>WI:</b> Western Interconnection               |
| <b>ERZ:</b> External Resource Zone                                                | <b>MOPI:</b> Michigan-Ontario PAR Interface            | <b>RRA:</b> Regional Resource Assessment (MISO)                            | <b>ZRC:</b> Zonal Resource Credits               |
| <b>FERC:</b> Federal Energy Regulatory Commission                                 | <b>MRI:</b> Marginal Reliability Impact (modeling)     | <b>RT:</b> Real-Time                                                       |                                                  |





## GLOSSARY

Where possible, definitions have been sourced from [MISO's Tariff](#), [Business Practice Manuals](#), and NERC standards.

**AFC (Available Flowgate Capability):** A measure of the flow capability remaining on a Flowgate for further commercial activity above already committed uses. Values are time and service type dependent.

**Ancillary Services:** Those services that are necessary to support Capacity and the transmission of Energy from Resources to Loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Asynchronous:** power systems or resources not synchronized in frequency or phase.

**CIL (Capacity Import Limit):** The amount of Planning Resources in MWs for an LRZ or ERZ determine by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.

**CEL (Capacity Export Limit):** The amount of Planning Resources in MWs for an LRZ or ERZ determine by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.

**Clogger (Constraint Logger):** The Energy Management System module which the Reliability Coordinators use to track, manage, and deactivate constraints in the Real-Time Market.

**Converter-Driven Stability:** instability caused by interactions between the control systems of electronic converters and the grid, potentially causing voltage or current oscillations, among other issues

**Co-optimization:** part of the grid management algorithm to simultaneously optimize multiple, related objectives (cost, availability, and reliability)

**CROW (Control Room Operations Window):** An application used by Operations Planning (formerly known as Outage Coordination) department to manage all internal (MISO) and external Reliability Coordinators equipment outages.

**CTS (Coordinated Transaction Scheduling):** Optimizes the efficiency of the interchange transactions at the MISO/PJM SEAM, and mitigates operational risks associated with significant NSI volatility.

**DA (Day Ahead) / RT (Real-Time) Markets:** MISO's DART system consists of two time-dependent markets, the Day Ahead (DA) and the Real Time (RT). The Day-ahead Energy Market (DA) is a forward market in which hourly Locational Marginal Pricing (LMP) values are calculated for each hour of the next operating day.

**Direct Loss of Load Capacity Accreditation Method:** MISO's capacity accreditation method, which via modeling analysis, evaluates a resource's performance during the most critical, high-risk hours of the year.

**Fast Active Power:** Grid-level service that rapidly injects or absorbs active power to stabilize the electrical grid and prevent larger disruptions.

**Flow Gate:** A representative modeling of a facility or group of facilities that may act as a constraint to power transfer on the Bulk Electric System.

**FTR (Financial Transmission Rights):** A financial instrument held by Market Participants to protect against paying congestion charges for scheduled injections and withdrawals. FTR values are determined by transmission congestion charges that arise in the Day-Ahead Energy and Operating Reserve Market.

**Interregional:** In the context of this document, demand, resources or transmission outside MISO's footprint, across a seam.

**Intra-Regional:** In this context, demand, resources or transmission within MISO's footprint.



**LMP (Locational Marginal Price):** Market clearing price for energy at a given location that is equal to the cost of supplying the increment of load at that location.

**LOLE (Loss of Load Expectation):** Expected or average number of days during a given period for which the available generation capacity is insufficient to serve demand. The industry has generally accepted an LOLE target of 1-day-in-10 years.

**MSSC (Most Severe Single Contingency):** A hypothetical event in an electric power system that would result in the greatest loss of resource output in megawatts (MW). The MSSC is calculated based on real-time system conditions and is a key benchmark for grid operators to ensure sufficient backup power to recover from a significant disturbance.

**Oscillation Damping:** Damping is a process of removing energy from a system. In an oscillating system, oscillations gradually decrease in size over time until the system comes to rest.

**PMU (Phasor Measurement Unit):** A device used in electrical grids to measure detailed characteristics of voltage and current in real-time.

**PRA (Planning Resource Auction):** The annual Planning Resource Auction is to ensure MISO has sufficient Planning Resources in its Local Resource Zones (LRZ). Import and export capabilities with external systems are considered in MISO's PRA indirectly through both firm and non-firm external support.

**PRM (Planning Reserve Margin):** The percentage above forecasted Coincident Peak Demand of Planning Resources for the Transmission Provider Region to meet the Loss of Load Expectation (LOLE), including a quantity sufficient to cover transmission losses.

**Planning Reserve Margin Requirement:** The amount of Zonal Resource Credits (ZRCs) required of each Load Serving Entity (LSE) with Coincident Peak Demand in a Local Resource Zone (LRZ) to meet the LSE's Resource Adequacy Requirements.

**Resonance Stability:** Ability to control oscillations and avoid voltage fluctuations, which can cause system instability and equipment damage.

**RA Hours:** minimum number of Resource Adequacy (RA) Hours for each season. Resource adequacy Hours are determined by evaluating historical operating data from the prior three years and are published prior to the annual Planning Resource Auction (PRA).

**Resource Adequacy:** the ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability.

**Rotor Angle (Power Angle):** angle between the internal electromotive force of the generator and its terminal voltage, which determines the amount of real power generated. Maintaining a stable rotor angle is critical for grid stability and enables multiple generators to operate in sync.

**Runback:** a power control strategy where electricity output is reduced in response to certain operational conditions or system demands.

**SE (State Estimator):** A computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements.

**Shadow Price:** the marginal value of a resource or constraint; quantifying the economic impact of limitations.

**STATCOM (Static Synchronous Compensator):** electronic device that continuously controls reactive power to regulate and stabilize voltage on a transmission network.



**TCR (Transmission Congestion Right):** a financial tool to allow market participants to hedge against price volatility caused by congestion.

**Thermal Overload:** condition where a motor can draw too much current (e.g., from increased load or voltage fluctuations), which can lead to overheating with potential to damage the equipment

**Thyristors:** solid state switches that can be switched on by adjusting the firing angle at a precise point in the AC waveform when the device is forward-biased (i.e., when the converter has positive voltage across its terminals).

**TLR (Transmission Loading Relief):** An interregional congestion management process that assesses external impacts on congestion, used across the eastern interconnection.

**UFLS (Underfrequency Load Shedding):** Automatic programs designed to protect the grid and prevent cascading blackouts when the system's frequency falls below safe operating limits. The main NERC standard governing these programs is [NERC PRC-006](#).

**Weak Grid Area:** A less-resilient system that is more vulnerable to voltage and frequency fluctuations with changes in energy flow.

**ZDC (Zonal Deliverability Charge):** Benefit to an LSE from transmission investment shown to alleviate transmission congestion and, as a result, lower internal zonal capacity obligations.

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**MISO thanks the National Lab of the Rockies (formerly National Renewable Energy Lab) for their contributions to this effort.**

## 9 Technical Appendix

### HVDC CONFIGURATIONS AND TOPOLOGIES

#### HVDC MONOPOLE

In an HVDC monopole configuration, there is one conductor or cable generally used for long distance power transfer while the return path is provided by ground electrodes. In other cases where the ground electrode return is not a feasible solution, a metallic return path might be used.

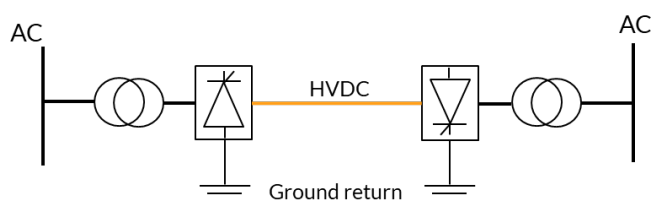


Figure 18: HVDC Monopole with ground return

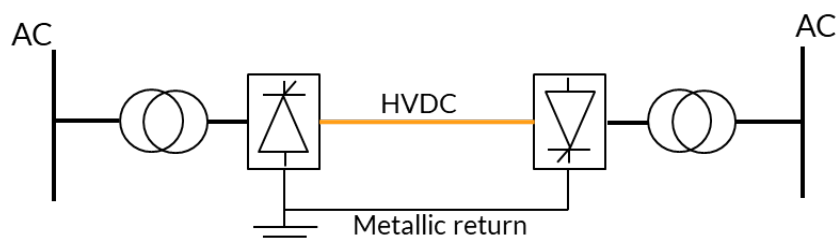


Figure 19: HVDC Monopole with metallic return

#### HVDC BIPOLE

An HVDC bipole has two conductors, one positive and the other negative, such that the common return path is only used to carry a small, unbalanced current during normal operation. The return path can be provided by ground electrodes or a dedicated metallic return (DMR). The DMR is used for relatively short transmission distance due to increased cost with high distance transmission.

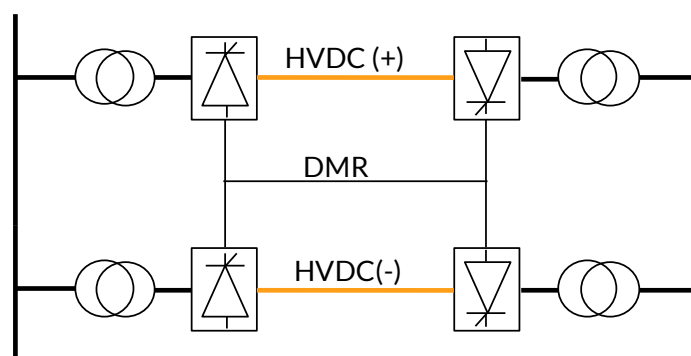


Figure 20. HVDC Bipole with dedicated metallic return

In an HVDC bipole, a sudden loss of one pole does not result in a total loss of transmission since partial power transfer can continue through the DMR. This inherent reliability of the bipole configuration, however, is constrained by the overload capacity of the remaining healthy pole.

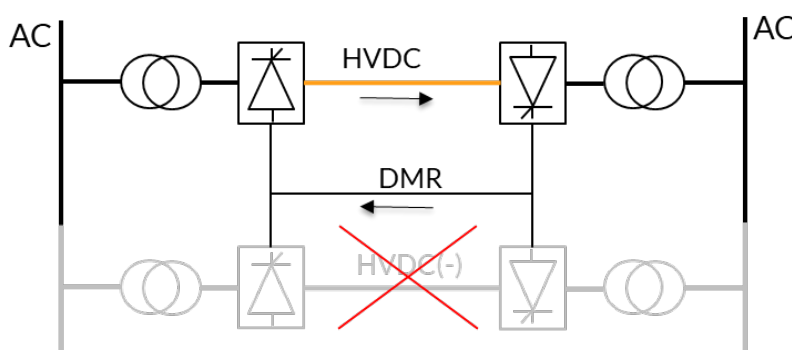


Figure 21: Inherent reliability of a bipole HVDC system

The Square Butte HVDC is an example of HVDC bipole in MISO footprint that connects power plant station in North Dakota to the Arrowhead converter station in Minnesota. The Manitoba Hydro system is another example of HVDC bipole system that synchronously connects to the MISO footprint using AC ties.

## BACK-TO-BACK CONVERTERS

In a back-to-back setting, the rectifier and inverter are in the same station and are mainly used for power transfer between two adjacent asynchronous AC grids. A back-to-back converter allows precise power transfer while keeping the two grids electrically independent. It decouples frequency control, preventing disturbances in one system from propagating to the other and thus enhancing reliability.

Within MISO footprint, the Mackinac back-to-back converter, located in Michigan's Upper Peninsula connects the Lower Peninsula and operate asynchronously. Beyond controlling power transfer between the two regions, the Mackinac converter plays a critical role in voltage regulation, reactive power support, and stability improvement for the relatively weak Upper Peninsula grid.

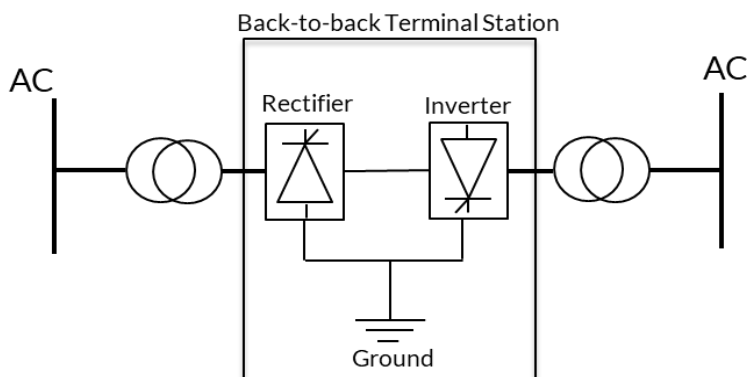


Figure 22: Back-to-back HVDC converter

## HVDC LINE TOPOLOGIES

### Two-Terminal HVDC Lines

A two-terminal HVDC system consists of two converter stations, one operating as a rectifier (AC to DC conversion) and the other as an inverter (DC to AC conversion), connected by a single DC transmission line. This configuration enables point-to-point power transfer between two geographically separated locations. It is the most common HVDC configuration being proposed in MISO footprint.

In point-to-point HVDC systems, there has not been strong need for installing dedicated DC circuit breakers as the DC faults are typically cleared through AC side isolation.

### Multi-Terminal HVDC Lines and Networks

A multi-terminal HVDC system interconnects three or more converter stations through a common DC network, allowing power to be exchanged among multiple regions. Each terminal can operate as a rectifier or inverter depending on system needs, with the total power supplied by rectifier stations equaling the total power absorbed by the inverter stations. This configuration offers greater flexibility but also introduces increased control and protection complexity. While multi-terminal HVDC systems can technically operate without DC circuit breakers, this means a fault anywhere on the DC network can de-energize the entire system. The use of HVDC circuit breakers could allow selective isolation of faulted sections, but these devices remain an evolving technology and are not currently part of MISO's planning considerations. From a planning perspective, two-terminal or, in limited cases, three-terminal HVDC configurations are the most practical considerations.

### DC Circuit Breakers (DCCBs)

The DC circuit breaker working principle is different than a conventional AC circuit breaker. During a short-circuit fault on an AC transmission line, the fault current offers zero crossings twice per cycle. For a 60 Hz system, this occurs 120 times per second. Conventional AC breakers are designed to take advantage of these natural zero crossings for arc extinction because at that instant, the dielectric strength of the medium between the breaker contacts is relatively higher.

In DC systems, no oscillation or natural zero crossings exist to assist interruption. Further, due to low DC link impedance, the fault current can reach extremely high levels within a few milliseconds, potentially damaging converters, cables, and other DC components. Artificial current zero-crossings must be created to enable fast current interruption. To slow down the rate at which fault current increases, DC reactors (DCRs) are placed in series with the line. These reactors increase system inductance that cause power losses during normal operation. They also increase system cost and complexity.

In DC grids with multiple converters and lines, selective fault clearing becomes critical and fast acting DCCBs are essential to isolate only the faulty section while allowing the rest of the DC grid to continue operating.

## MARKET IMPACT ASSESSMENT

### COMPARATIVE ANALYSIS OF HVDC MARKET INTEGRATION

#### North American RTO Market

Existing HVDC facilities across North America exhibit diverse operational characteristics shaped by BA relationships, institutional arrangements, and market integration approaches. Table 6 summarizes key HVDC facilities and their participation characteristics across North American RTOs. The patterns revealed in these implementations inform potential approaches for future HVDC integration.

| Facility             | RTOs/BAs    | BA Relationship  | RT Dispatch       | Ancillary Services  | Congestion Mgmt.   | Loss Treatment         |
|----------------------|-------------|------------------|-------------------|---------------------|--------------------|------------------------|
| Trans Bay Cable      | CAISO       | Intra-BA         | 5-min SCED        | No                  | Yes (co-optimized) | Not modeled explicitly |
| Pacific DC Intertie  | CAISO, BPA  | Inter-BA (async) | Hourly schedule   | No                  | Limited            | Loss-adjusted schedule |
| Neptune              | PJM-NYISO   | Inter-BA (sync)  | Hourly (merchant) | No                  | No (load pocket)   | Operator internalized  |
| Cross Sound Cable    | ISONE-NYISO | Inter-BA (sync)  | Hourly e-Tag      | Limited (voltage)   | No (load pocket)   | Operator internalized  |
| Linden VFT           | PJM-NYISO   | Inter-BA (sync)  | DA price-based    | No                  | No                 | Operator internalized  |
| Manitoba Hydro (EAR) | MISO-MH     | Inter-BA (async) | 5-min SCED        | Yes (Reg, Reserves) | Yes (at proxy bus) | Operator internalized  |
| Phase I/II           | ISO-NE-HQ   | Inter-BA (async) | Hourly e-Tag      | Limited             | No                 | Operator internalized  |

Note: RT = Real-time; DA = Day-ahead; Reg = Regulation; async = asynchronous; sync = synchronized

**Table 6: HVDC Facility Characteristics in North American RTOs**

#### Key Observations

- Intra-BA facilities like Trans Bay Cable can be integrated into 5-minute real-time dispatch because a single market operator controls both terminals.

- Synchronized inter-BA facilities face greater constraints. No example exists of synchronized inter-BA HVDC facilities receiving coordinated 5-minute economic dispatch from both RTOs.
- Asynchronous inter-BA connections demonstrate greater flexibility. MISO EAR model enables Manitoba Hydro to participate in 5-minute SCED despite the asynchronous connection.
- Ancillary service participation correlates strongly with dispatch integration. Synchronized inter-BA facilities generally do not provide ancillary services.
- Congestion hedging products are available only within single RTO footprints. No cross-BA congestion hedging products exist for inter-BA HVDC facilities.
- Despite the non-linear, direction-dependent nature of HVDC losses, no US RTO models these losses explicitly in real-time LMP calculations.

## **Global HVDC Integration**

### **Australia**

In Australia's National Electricity Market (NEM), HVDC facilities like Directlink and Murraylink are treated as dispatchable resources with 5-minute dispatch targets co-optimized with generation and load. HVDC losses are calculated every 5 minutes but not modeled as non-linear functions in dispatch. AEMO applies specialized procedures for ramping and frequency control, including linear ramping via AGC with 4-second updates.

### **Europe**

HVDC interconnectors such as IFA (UK-France), BritNed (UK-Netherlands), and Nemo Link (UK-Belgium) are integrated through Single Day-Ahead Coupling (SDAC) and Single Intraday Coupling (SIDC) frameworks. HVDC losses are allocated using pro-rata or marginal loss factors in settlement rather than modeled in dispatch engines. This approach illustrates forward market coordination across sovereign boundaries without real-time nodal dispatch.

## **TECHNICAL FORMULATIONS FOR INTRA-REGIONAL HVDC**

### **Circular Flow Analysis**

Circular flow between AC and HVDC paths can occur under both fixed and dispatchable operations when optimization attempts to manage congestion or respond to loss differentials. NLR research identifies three distinct mechanisms that can cause circular flow

### **Linear Loss Approximations**

MISO's SCUC and SCED models use linear approximations to represent transmission losses. These work reasonably well for incremental AC dispatch but can be inaccurate with large HVDC flow changes. Because HVDC can shift hundreds of megawatts rapidly, it can move the system far from the linearization point, making loss estimates inaccurate. This can lead the optimization to dispatch HVDC in ways that appear economic under the linear model but are suboptimal when actual non-linear losses are considered. Two issues are observed with initial studies:



Issue 1: Large deviations between AC power flow solutions and linear approximations may lead to inaccuracies or oscillations. Dispatchable HVDC may cause greater deviations from the linear approximation.

Issue 2: Under a linear approximation, losses become negative when flow reverses direction, whereas in reality, losses increase with the absolute value of flow. This inaccurate linear loss model can lead to circular flows and large errors in SCUC/SCED loss calculations.

## Negative Prices and Loss Maximization

Negative LMPs (often driven by renewable generation with production tax credits or must-run status) can lead to counterintuitive outcomes. Under negative pricing, losses take on negative economic value, meaning the system is effectively paid to consume energy. The optimization may favor increased losses, interpreting them as cost-reducing. This can create circular flows between HVDC and AC lines, where power loops through the system to inflate losses. Case studies show this can emerge under both fixed and dispatchable HVDC schedules.

## AC Congestion Management

Even under positive prices, circular flows between AC and HVDC paths can emerge when optimization manages AC congestion. Research illustrates how congestion on specific AC corridors leads to HVDC dispatch patterns that create circular flows. These solutions are economically rational (they reduce congestion at lower cost) but result in complex power flow patterns. The issue is more likely when HVDC connects regions that also have strong AC ties.

## Piecewise Linear HVDC Loss Formulation

A piecewise linear (PWL) loss model provides a practical approach that balances computational tractability with necessary accuracy for optimal dispatch. Under this approach, the HVDC loss characteristic is approximated as a series of linear segments.

In the following formulation,  $hl_{i,h}$  is the HVDC losses under “from end MW”  $H_{from,h} = hf_{i,h}$ .  $hf_{i,h}$  may be positive or negative. But  $hl_{i,h}$  is non-negative. HVDC “to end MW” is  $H_{to,h}$ . The following piece wise linear formulation uses continuous variables. It can solve HVDC losses at the correct segment when price is positive. The index for HVDC is  $h = 1, \dots, N_h$

$$H_{to,h} = H_{from,h} - HLoss_h \quad h = 1, \dots, N_h$$

$$H_{from,h} = \sum_{i=1}^m w_{i,h} hf_{i,h} \quad h = 1, \dots, N_h$$

$$HLoss_h = \sum_{i=1}^m w_{i,h} hl_{i,h} \quad h = 1, \dots, N_h$$

$$\sum_{i=1}^m w_{i,h} = 1 \quad h = 1, \dots, N_h$$

$$w_{i,h} \geq 0, \text{ for } i = 1, \dots, m \quad h = 1, \dots, N_h$$

However, when price is negative, it maximizes losses and solves at the highest loss segment even if the HVDC flow is solved at the lower segment. Theoretically, binary variables need to be introduced to ensure the correct solution. Given the small number of HVDC lines, the impact from adding binary variables in SCUC is expected to be small. Adding binary variables in SCED may cause solution time increase. Heuristic methods may be developed to mitigate the issue.

### HVDC Settlement Formulations

The market clearing identity includes a term for HVDC flows that reflects the net economic impact of transferring power across regions. This can be expressed as:

$$\sum_{g=1}^{N_g} P_g LMP_{b_g} - \sum_{b=1}^{N_b} L_b LMP_b - \sum_{l=1}^{N_l} T_{max,l} \mu_l + \sum_{h=1}^{N_h} (H_{to,h} LMP_{to,h} - H_{from,h} LMP_{from,h}) = 0$$

where,

$P_g$ : Cleared generation cleared at generation  $g$  located at bus  $b_g$

$l_b$ : Load at bus  $b$

$T_{max,l}$ : Limit of AC transmission constraint  $l$

$\mu_l$ : Shadow price of constraint  $l$

$H_{from,h}$  and  $H_{to,h}$ : HVDC flow at the sending and receiving ends of HVDC line  $h$

$LMP_{from,h}$  and  $LMP_{to,h}$ : LMPs at the HVDC terminals

This identity ensures that the total payments by load equal the payments to generators, plus congestion rents from AC and HVDC flows.

The net settlement is the HVDC-specific term in the power balance:

$$Net\ Settlement_h = \sum_{h=1}^{N_h} (H_{to,h} LMP_{to,h} - H_{from,h} LMP_{from,h})$$

### Key Settlement Implications

- When HVDC is not binding at its limit, the net settlement term may be zero, and the cost of HVDC losses may be reflected in AC congestion rents.
- When HVDC is binding at the limit, the net settlement term may not be zero. Additional settlement rules may be needed, either through direct HVDC settlement or other allocation mechanisms.
- This formulation ensures HVDC flows are treated consistently with other transmission elements, with the cost of HVDC losses and value of congestion relief fully reflected in market outcomes.

### Potential Mitigation Strategies

Several enhancements to SCED and SCUC formulations are being researched to address circular flow and loss modeling challenges:

### *Piecewise Linear and Hybrid Loss Models*

HVDC losses can be modeled using PWL formulations with either continuous or binary variables. Continuous models may suffice under positive prices, but binary variables may be needed to prevent incorrect segment selection under negative LMPs. Given the small number of HVDC lines, computational impact in SCUC is expected to be manageable.

### *Integer Variable Methods for Flow Direction*

To improve flow direction optimization and avoid oscillatory solutions, integer or binary variables can be introduced to explicitly model flow direction. This provides more stable solutions when HVDC flow reversals occur.

### *Circular Flow Detection and Fallback Logic*

Software tools can be implemented to detect circular flows in AC or HVDC paths. When such flows are identified, the optimization can revert to fixed-loss models or apply corrective constraints to eliminate the economic incentive for loss-maximizing behavior. Losses would be fixed at expected values based on forecasted loading rather than optimized as variables.

### *Angle Difference Constraints*

Bus angle difference constraints between HVDC terminals can effectively mitigate circular flows. These constraints can be derived from HVDC bus angle difference to bus injection sensitivities and incorporated into SCED/SCUC. Preliminary studies show this approach can be effective. Additional tools may be needed to identify angle or flow limits based on voltage or transient stability considerations.

## **INTERREGIONAL COORDINATION AND PARTICIPATION**

### **Coordination mechanisms by neighboring balancing authority**

The applicability of coordination mechanisms varies significantly across MISO's neighboring Balancing Authorities, depending on market structure, regulatory jurisdiction, and existing coordination agreements. Table 7 summarizes coordination mechanisms in place with each neighbor.

| Neighbor              | BA Type                            | Coordination Mechanism         | Market-Based? | HVDC Today? | Coordination | HVDC Integration Considerations                                                                              |
|-----------------------|------------------------------------|--------------------------------|---------------|-------------|--------------|--------------------------------------------------------------------------------------------------------------|
| <b>Manitoba Hydro</b> | Synchronized (Asynchronous Source) | EAR Model (Dynamic Scheduling) | Partial       | Yes         | Medium       | Manitoba's HVDC is internal to its own system; asynchronous with MISO; not generalizable to synchronous HVDC |
| <b>TVA / AECI</b>     | Synchronized, Non-Market           | Bilateral Scheduling + TLR     | No            | No          | Low          | HVDC would be limited to fixed schedules; no redispatch capability                                           |
| <b>PJM</b>            | Synchronized, Market               | M2M + CTS                      | Yes           | No          | High         | Framework exists; enhancements needed for dynamic HVDC dispatch                                              |
| <b>SPP</b>            | Synchronized, Market               | M2M Only                       | Yes           | No          | Medium-High  | Similar to PJM; lacks CTS; modeling differences may affect HVDC                                              |
| <b>IESO</b>           | Synchronized, Market (Non-FERC)    | PAR Coordination               | Partial       | No          | Medium       | Coordination possible, but limited by jurisdiction and lack of M2M                                           |

**Table 7: Interregional Coordination Mechanisms by Neighboring BANLR research on interregional coordination**

NLR is developing foundational software and coordination methods to evaluate the impact of different coordination configurations at different operational stages. The Sienna Decomposition platform provides capability to study distributed coordination algorithms across RTOs.

#### *Key Capabilities*

- Benchmark optimal mathematical models for each configuration with detailed representation of multi-RTO market clearing, area interchange, transmission loop flow, and both intra- and interregional HVDC dispatch
- Multi-stage simulation with flexibility to study different configurations at different stages (day-ahead, real-time)
- Consistent measurement of economic and reliability impacts through emulation functions that retrieve dispatch results from different grid operators and calculate pre- and post-contingency flows

### **REAL-TIME COORDINATION METHODS**

Real-time market coordination between two RTOs is generally implemented in distributed fashion. RTOs exchange shadow prices, relief requests, or price curves to achieve dispatch, flow, and price convergence. However, limited information exchange and time delays may cause convergence issues or sub-optimal solutions.

#### **Coordination Approaches**

##### *RT1: Shadow Price and Relief Request Exchange*

Used in existing MISO-PJM and MISO-SPP M2M coordination. Requires minimal information exchange but has limitations: (1) Shadow prices indicate which side can provide lower-cost relief but do not quantify how much cheaper relief could be provided; (2) Fixed relief requests may cause 'chattering' or 'oscillation' issues, exacerbated by communication delays; (3) Determining relief requests based solely on SCED solutions is not straightforward; a shadow price curve showing the relationship between requested relief and shadow price could provide more useful information.

##### *RT2: Price Curve Exchange*

Used in ISO-NE and NYISO Coordinated Transaction Scheduling. Net interchange is modeled as injections and withdrawals at proxy interface buses. ISO-NE generates forecast price curves that NYISO uses to clear CTS bids. However, price forecast errors and network congestion may cause counter-intuitive flows.

##### *RT3: Marginal Equivalent Method*

Proposed by ISO-NE to exchange marginal resources and incorporate them into neighboring RTO market clearing. This represents the neighboring RTO through its marginal units, providing more accurate reflection of power balance and transmission constraint impacts. However, identifying marginal units and co-optimizing reserves can be challenging.

##### *RT4: Enhanced M2M with Relief Cost Curves*



NLR research proposes improvements to existing M2M methods: (1) Improvement of shadow price and relief request calculation methods to address oscillation issues; (2) Generating and exchanging price curves for each coordinated M2M transmission constraint, with each RTO including price curves from neighboring RTOs in its SCED optimization.

## RELIABILITY OPERATIONS IMPACT ASSESSMENT

### ANGULAR STABILITY SUPPORT

Figures 23 and 24 below illustrates the relative phase angle trajectories of major buses in a simplified 176-bus model of WECC. The bus angle trajectories are from a 4-cycle Single Line to Ground (SLG) fault cleared at 0.67 seconds. Figure 24 presents the same fault scenario in Figure 23, but with an immediate 500 MW transfer through HVDC lines. The added HVDC transfer appears to reduce the overall angular separation among the buses.

A high angular separation drives current flow that sometimes cause protective relays to trip on overloads, potentially causing cascading outages. Engineers at the Bonneville Power Administration (BPA) demonstrated that small angle differences caused by a fast power change on an HVDC link could have prevented the Dec. 14, 1994, blackout in the WECC.<sup>24</sup>

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<sup>24</sup> Rovnyak, S.M. & Taylor, C.W. & Mechenbier, J.R. & Thorp, J.s. (1995). Plans to Demonstrate Decision Tree Control Using Phasor Measurement for HVDC Fast Power Changes.

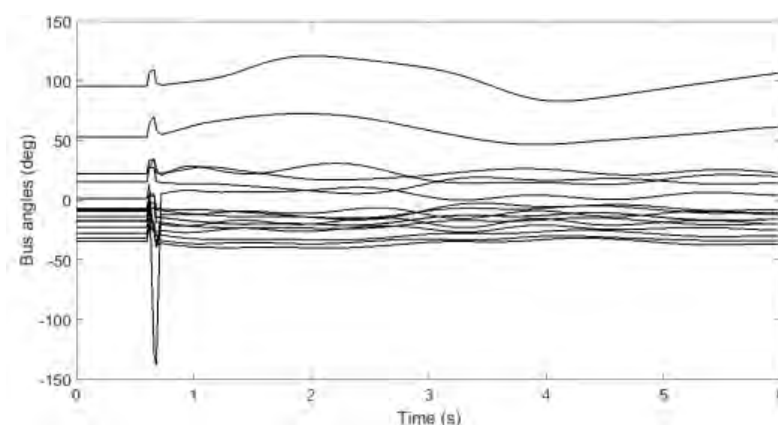


Figure 23: Relative phase angle difference for a 4-cycle Single Line-to-Ground fault

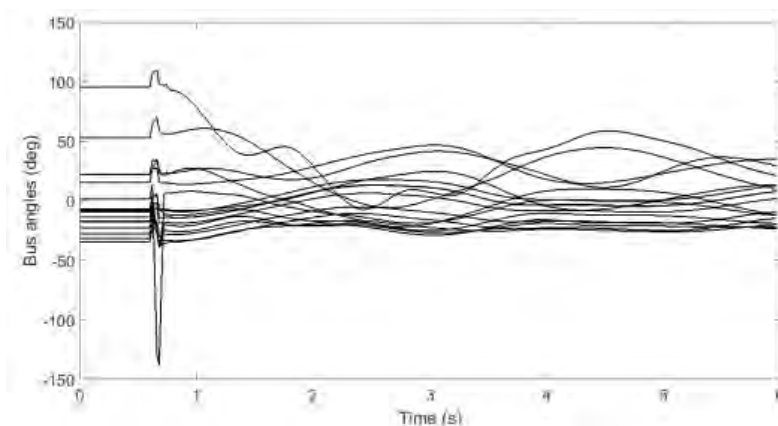


Figure 24: Relative phase angle difference for the same fault in Figure 6 with a 500 MW HVDC transfer

## CASE STUDY: STABILITY BENEFITS OF HVDC

### Pacific DC Intertie (PDCI)

The Pacific DC Intertie, a  $\pm 500$  kV, 3,100 MW HVDC transmission line connecting Oregon and California, provides a notable example of active damping control.<sup>25</sup> Since 2017, the system has operated with a Wide Area Damping Controller (WADC) that uses real-time phasor measurement unit (PMU) feedback to target inter-area oscillations, particularly the North-South "B mode" oscillation around 0.3 Hz. This implementation has proven effective, significantly enhancing the damping of system oscillations without negatively affecting other system modes. The PDCI demonstrates how HVDC technology, when equipped with advanced control systems, can be successfully integrated into wide-area stability enhancement strategies.

### Rio Madeira and Xingu HVDC Systems

Brazil's large-scale HVDC projects—the Rio Madeira and Belo Monte (Xingu) systems— highlight the role

<sup>25</sup> Pierre, Brian & Wilches-Bernal, Felipe & Schoenwald, David & Elliott, Ryan & Trudnowski, Daniel & Byrne, Raymond & Neely, Jason. (2019). Design of the Pacific DC Intertie Wide Area Damping Controller. IEEE Transactions on Power Systems. PP. 1-1. doi: 10.1109/tpwrs.2019.2903782.

of HVDC in enhancing power system stability.<sup>26</sup> The Rio Madeira project consists of two  $\pm 600$  kV bi-poles rated at 3,150 MW each, while the Xingu system includes two  $\pm 800$  kV bi-poles, each rated at 4,000 MW. It is worth noting that the Madeira bipoles are interconnectors, while both the Xingu-Estreito and Xingu-Terminal Rio are embedded HVDC systems.

The Xingu HVDC systems offer a strategic transfer path for renewable generation from the Northeast (NE) to the Southeast (SE) load centers. In situations where AC corridors from the NE to SE are saturated or compromised, the Xingu HVDC links provide an alternate, controllable route for balancing regional surpluses and deficits. In this context, the bipoles act as flexible, high-capacity relief valves for the AC network, increasing dispatch efficiency under high IBR penetration.

Both systems are equipped with sophisticated master control schemes designed for coordinated operation. These control systems incorporate oscillation damping capabilities, allowing the HVDC links to support the AC network not only in steady-state power transfer but also in stabilizing dynamic disturbances. Studies and integration tests have shown that excluding the power oscillation damping logic leads to loss of damping and potential instability in oscillatory electromechanical modes, especially after major contingencies.

### **Itaipu HVDC System**

The Itaipu HVDC system ( $\pm 600$  kV) allows the full exploitation of the 50 Hz generation from the Paraguayan share of Itaipu, which would otherwise be limited due to asynchronous frequency and load constraints in Paraguay. Since the Paraguayan system operates at 50 Hz, its surplus power is sent to Brazil's 60 Hz system using the HVDC link without causing frequency instability.

### **INELFE France-Spain VSC links**

The INELFE project, connecting France and Spain via two 1,000 MW VSC links, was designed to strengthen the interconnection across a natural bottleneck in the European grid.<sup>27</sup> The project addressed challenges associated with maintaining voltage and frequency stability across two independently operated synchronous areas. The VSC terminals are configured not only to transmit power but also to provide ancillary services including voltage control, frequency response, and black-start capability. To further enhance stability, the system uses AC emulation and custom-designed protection schemes that allow it to dampen inter-area oscillations. Since its commissioning in 2015, INELFE has reliably supported system recovery after faults and improved dynamic voltage response between the Iberian Peninsula and the rest of Europe.

### **NordLink HVDC**

Commissioned in stages between 2019 and 2021, the NordLink HVDC line connects hydro-rich Norway with Germany's variable renewable-heavy grid.<sup>28</sup> One of the first large-scale point-to-point VSC-HVDC links in Europe, NordLink was designed with voltage stability as a key operational objective. During initial

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<sup>26</sup> Macleod, N., Kayibabu, B., Sellick, Rob & Kirby, Neil. (2010). [A  \$\pm 600\$  kV HVDC Transmission project to access remote renewable energy sources.](#)

<sup>27</sup> Entsoe, HVDC Links in System Operations, Technical Paper. December 2019. [https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/20191203\\_HVDC%20links%20in%20system%20operations.pdf](https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/20191203_HVDC%20links%20in%20system%20operations.pdf)

<sup>28</sup> CIGRE Science and Engineering, CSE No 27 – January 2023. B4 – Transmission system testing of a VSC based HVDC system. <https://cse.cigre.org/cse-n027/b4-transmission-system-testing-of-a-vsc-based-hvdc-system.html>

commissioning, the converters were tested in STATCOM mode - operating with full reactive power capability without transmitting active power. This ensured the link could provide voltage support even when one or both poles were not transferring active power. Selected pole performed controlled ramping to monopolar operation over three seconds while continuing to provide reactive power, thereby maintaining AC voltage stability during the transient.

## INTEGRAL SQUARE BUS ANGLE (ISBA) INDEX

The ISBA index quantifies the overall network stress by measuring the voltage phase angle differences of the system.<sup>29</sup> Prior to the calculation, the bus angle trajectories must be unwrapped to eliminate discontinuities at +/- 180 degrees. The selected set of buses does not need to cover the entire system but should include representative nodes from all major areas. At each time step, the Square Bus Angle (SBA) index is first computed as-

$$SBA(t) = \sum_i M_i (\theta_i(t) - \theta_{coa}(t))^2 \quad (9.1)$$

$$\theta_{coa}(t) = \frac{\sum_i M_i \theta_i(t)}{\sum_i M_i} \quad (9.2)$$

where  $\theta_i(t)$  represent continuous trajectories reconstructed from the bus angles and constants  $M_i$  are weighing factors that reflect the relative importance of different locations. The ISBA index is then obtained by integration  $SBA(t)$  over time either by using a sliding window or a low pass filter.

A higher ISBA value indicates greater overall angular separation between buses, signifying a more stressed system that is operating closer to instability.

## SHORT-CIRCUIT RATIO (SCR) TEST

A SCR test is used to evaluate how well a converter can operate and remain stable when connected to a weak AC grid. In an HVDC system, a weak grid can be simulated by increasing the impedance between the converter's POI bus and the AC network, thereby reducing the short-circuit ratio (SCR) as seen by the converter. Initially at the steady state, the line impedance between bus 4 and bus 7 in Figure 25 is modified so that the HVDC system operates with SCR = 20 (very strong grid). During the simulation, SCR is gradually reduced to emulate the weaker grid conditions as follows:

| Time (s) | SCR Value | Grid Strength |
|----------|-----------|---------------|
|----------|-----------|---------------|

<sup>29</sup> S. M. Rovnyak, M. N. Nilchi, D. W. Longbottom and D. C. Vasquez, "Angle stability predictive indices," 2012 IEEE Power and Energy Society General Meeting, San Diego, CA, USA, 2012, pp. 1-6, doi: 10.1109/PESGM.2012.6344976



|      |     |                   |
|------|-----|-------------------|
| 0-1  | 20  | Very strong       |
| 1-5  | 5   | Moderately strong |
| 5-10 | 3   | Weak              |
| 10+  | 1.5 | Very weak         |

Table 8: Variable SCR test

At each SCR level, the corresponding impedance is computed and applied to the line connecting the inverter to the AC grid. Results show that for a very weak grid, the system experience high oscillations, especially immediately after changes in the grid strength, indicating the limit of stable operation. The test VSC-HVDC converter is injecting the desired 400 MW real power into the AC system despite those oscillations during the lowest SCR scenario.

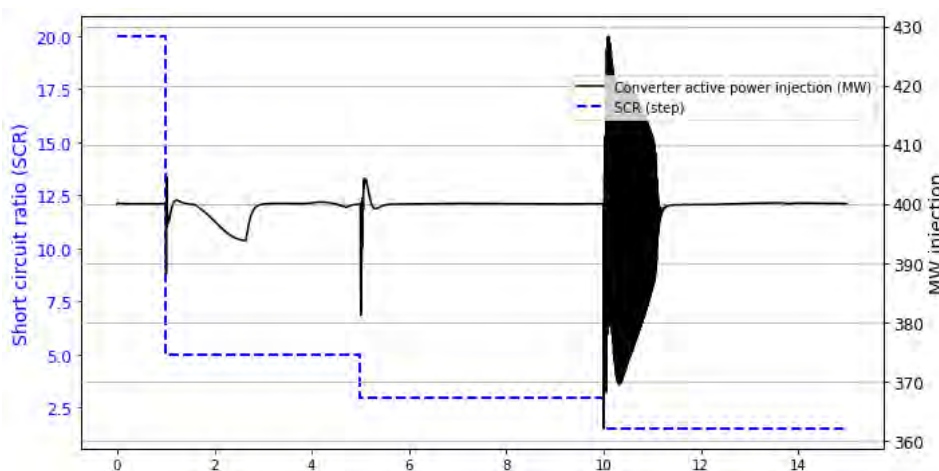


Figure 25: Converter active power injection (MW) under varying SCR

The tests performed here serve as a proxy for evaluating the robustness of HVDC converters. MISO's 2023 attributes analysis mentions that while SCR remains a useful preliminary screening tool for assessing converter's stability as simulated above, it may not fully capture grid strength under high IBR penetration, requiring the use of a new 'dynamic impedance' method.<sup>30</sup> In practice, system operators or planning teams may require project developers to submit validated dynamic models of their converters. These models enable the stability analysis team to conduct critical tests such as voltage and frequency ride-throughs and weak grid assessments.

## PLANNING IMPACT ASSESSMENT

**Maximum Power Transfer Limit of AC Lines.** Every load carrying series impedance branch has a maximum power transfer limit. An accurate approximation of the real power transfer through a purely

<sup>30</sup> [MISO Attributes Roadmap Technical Appendix](#)

reactive impedance branch (i.e., a branch where branch resistance is neglected) is given by equation (1) below:

$$RPT = |V_s| |V_r| \sin(\theta) / |X_{Br}| \quad (1)$$

Where

RPT = Real Power Transfer through Branch in per unit

$V_s$  = Sending-end Terminal Voltage in per unit

$V_r$  = Receiving-end Terminal Voltage in per unit

$X_{Br}$  = Series Reactive Impedance of Branch in per unit

$\theta$  = Angle in degrees or radians by which the voltage at the sending-end terminal leads the voltage at the receiving-end terminal.

In the equation above, real power losses are ignored, so real power transferred into the sending-end terminal of the branch is equal to real power transferred out of the receiving-end terminal of the branch.

A maximum power transfer limit can be established for a reactive impedance branch based on equation (1) by assuming the angular difference between the sending-end terminal voltage and receiving-end terminal voltage is  $90^\circ$  since the maximum value of  $\sin(\theta)$  is 1.0 and occurs at an angle of  $90^\circ$ . The formula for the maximum power transfer limit of an impedance branch is thus given by equation (2) below:

$$MPTL_{Branch} = |V_s| |V_r| / |X_{Br}| \quad (2)$$

Where

$MPTL_{Branch}$  = Maximum Real Power Transfer through Branch in per unit

For a transmission line circuit branch or transmission transformer branch that can be modeled as a series reactance within a power system, equation (2) is a true hard limit for the transmission line circuit branch or transmission transformer branch, but not necessarily the most conservative maximum power transfer limit if  $X_{Br}$  represents the reactive impedance of just the branch and  $V_s$  and  $V_r$  represent the voltages at the sending-end and receiving-end terminals of the branch respectively. That is, the true maximum power transfer limit must consider both the characteristics of the transmission branch in question as well as the characteristics of the rest of the system.

To understand the overall system impact on the maximum power transfer limit of a single transmission branch, consider the branch and system equivalent illustrated in Figure 26 below.

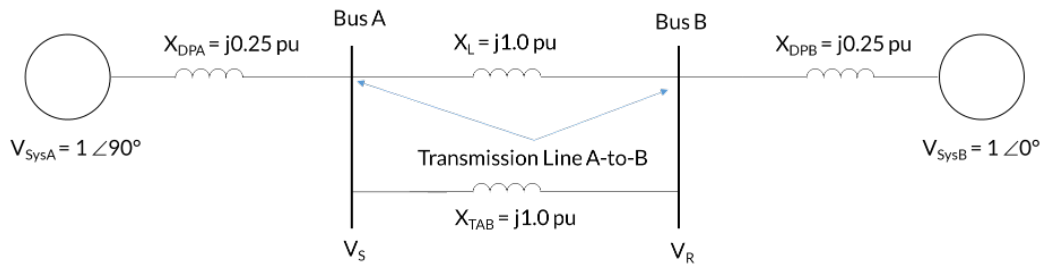


**Figure 26: Impedance Branch and Equivalent System**

Per Figure 26, a single transmission branch exists between Bus A and Bus B and is represented by the reactive impedance  $X_{Br}$ . The rest of the system is modeled via an adjusted transfer impedance<sup>31</sup> between Bus A and Bus B ( $X_{AdjTranAB}$ ), equivalent source impedances at both Bus A and Bus B ( $X_{EqScA}$  and  $X_{EqScB}$  respectively) and equivalent independent voltage sources behind each equivalent source impedance whose magnitudes and angles are set to replicate real power transfer from Source A (acting as a generator) and Source B (acting as a load) and are designated as  $V_{SysA}$  and  $V_{SysB}$  respectively.

The magnitude of the total transfer impedance<sup>32</sup> between Bus A and Bus B is based on the parallel combination of the transmission branch impedance ( $X_{Br}$ ) and the adjusted transfer impedance ( $X_{AdjTranAB}$ ) between the buses and is equal to  $j0.5$  per unit (i.e.,  $j1.0 || j1.0 = j0.5$ ). The sum of the two equivalent source impedances ( $X_{EqScA}$  and  $X_{EqScB}$ ) is also equal to  $j0.5$  per unit (i.e.,  $j0.25 + j0.25 = j0.5$ ). The maximum real power transfer from Source A to Source B is limited by the total equivalent system impedance between the two equivalent sources (which is the sum of the two equivalent source impedances and the total transfer impedance between Bus A and Bus B). The total equivalent reactance between the two sources is designated as  $X_{TotSys}$  and is equal to  $j1.0$  per unit (i.e.,  $j0.25 + j0.5 + j0.25 = j1.0$ ). The maximum real power transfer from Source A to Source B is determined based on an angular displacement between the Equivalent Source A voltage and the Equivalent Source B voltage of  $90^\circ$  and is designated as  $MPTL_{System}$ . Using equation (2) and substituting  $V_{SysA}$ ,  $V_{SysB}$  and  $X_{TotSys}$  for  $V_S$ ,  $V_R$  and  $X_{Br}$  respectively yields the following:

$$MPTL_{System} = |V_{SysA}| |V_{SysB}| / |X_{TotSys}| = (1.0)(1.0) / 1.0 = 1.0 \text{ per unit} \quad (3)$$

Where

$MPTL_{System}$  = Maximum Real Power Transfer across System in per unit

$V_{SysA}$  = Equivalent source voltage at Bus A terminal in per unit

$V_{SysB}$  = Equivalent source voltage at Bus B terminal in per unit

$X_{TotSys}$  = Equivalent total system reactance between equivalent voltage sources in per unit

<sup>31</sup> The term *adjusted transfer impedance* corresponds to the transfer impedance that would exist if the transmission branch in question were out of service, thus allowing the transmission branch impedance to be modeled separately.

<sup>32</sup> The term *total transfer impedance* corresponds to the transfer impedance that would exist if the transmission branch in question were in service, so *total transfer impedance* is the true transfer impedance for a two-bus equivalent model.

Because in this example the transmission branch impedance is equal to the adjusted transfer impedance between Bus A and Bus B (i.e., the transfer impedance between Bus A and Bus B with the transmission branch removed), it can be inferred that 50% of the maximum power transfer between Source A and Source B will flow in the transmission branch while the remaining 50% of the maximum power transfer between Source A and Source B will flow through the adjusted transfer impedance based on simple current division. Therefore, in this particular case, the maximum power transfer limit for the transmission branch with consideration given to the impact of the external system, which is designated as  $MPTL_{BranchSystem}$ , is 0.5 per unit, or 50% of  $MPTL_{System}$  based on equal current division between the impedance branch and the parallel adjusted transfer impedance.

The maximum power transfer limit of just the branch (i.e.,  $MPTL_{Branch}$ ) without consideration of the external system is calculated as follows:

$$MPTL_{Branch} = |V_S||V_R| / |X_{Br}| = (1.0)(1.0) / 1.0 = 1.0 \text{ per unit} \quad (4)$$

Therefore, while the maximum power transfer limit calculated for the branch without regard to the external system (i.e.,  $MPTL_{Branch}$ ) is a valid limit, it is not necessarily the most conservative limit. In this extreme example of very weak system terminals connected by two parallel low impedance transmission branches, the true maximum power transfer limit is 50% lower than it would be if the external system was not considered at all. However, if we assumed infinite system strength at each terminal corresponding to equivalent source impedance magnitudes of zero, the maximum power transfer limit of the line with the external system ignored would be the same as the maximum power transfer limit calculated with consideration of the external system. Thus, for situations where the systems are strong at each of the line terminals and the line impedance is high (i.e., the transmission line is long and interconnects together two distant but strong systems), calculation of the maximum power transfer limit of the branch without consideration of the external system is a good approximation of the true maximum power transfer limit of the line (though not a worst-case approximation).

Figure 27 below illustrates how  $MPTL_{BranchSystem}$  (the maximum power transfer limit of a branch when consideration is given to the external system) varies as a percentage of  $MPTL_{Branch}$  (the maximum power transfer limit of a branch when the external system is ignored) for equivalent system impedances at Bus A and Bus B that vary from 0% to 50% of the reactive impedance of the branch in question. Plots are made assuming no parallel path to the branch (blue plot) and with a parallel equivalent branch (i.e., adjusted transfer impedance) with the same impedance as the branch in question (red plot).

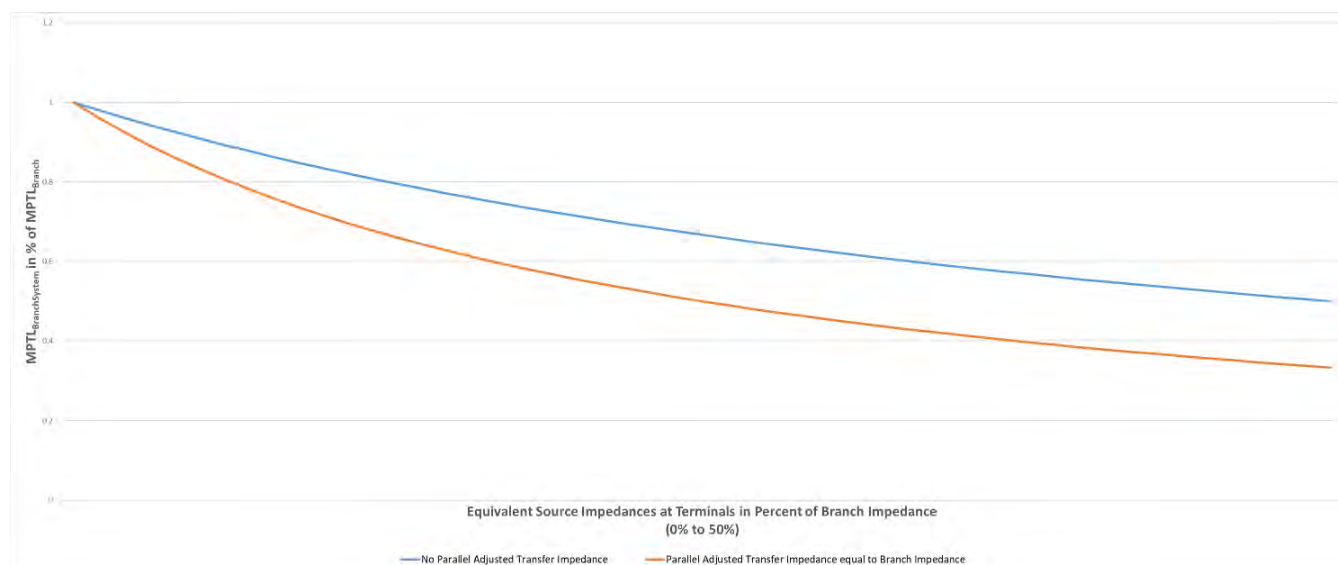


**Figure 27: Comparison of Maximum Power Transfer Limits in Per Unit with and without parallel transfer impedance equal to branch impedance**

Per Figure 27, the maximum power transfer limit of the branch with and without consideration of the external system are identical only when the equivalent system impedances are zero (infinite system strength at each terminal). An increase in the equivalent system impedances at each bus from 0% to 50% of the branch impedance in question will cause the true maximum power transfer level to decrease substantially. In cases where there is no parallel path between the buses, equivalent source impedances at each bus equal to 50% of the branch impedance would result in  $MPTL_{BranchSystem}$  (the maximum power transfer limit of the branch with the external system considered) to drop down to 50% of the  $MPTL_{Branch}$  (the maximum power transfer limit of the branch when the external system is ignored). Furthermore, assuming the branch is in parallel with an adjusted transfer impedance equal to the branch impedance, equivalent source impedances at each bus equal to 50% of the branch impedance would result in  $MPTL_{BranchSystem}$  (the maximum power transfer limit of the branch with the external system considered) to drop down to 33% of the  $MPTL_{Branch}$  (the maximum power transfer limit of the branch when the external system is ignored). In general, the extreme example above would not be an issue because it would only apply to short transmission lines between weak buses where the equivalent source reactive impedances could not be ignored relative to the transmission line reactance (points to the right in the graph above). In these situations, the thermal limits of the transmission line would likely be well below the true maximum power transfer limit of the transmission line since low branch impedances create very large branch maximum power transfer limits ( $MPTL_{Branch}$ ). However, in the paper titled “Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines”<sup>33</sup> written in 1979 by three AEP engineers, it was pointed out that system strength could be an issue for determining the angular loadability of 765 kV lines or UHV lines prior to full development of such systems, where the relative

<sup>33</sup> Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

strength of the terminals could be weak compared to the capacity and impedance of a 765 kV or UHV transmission line. In this particular paper, loadability was based on the line length (expressed in percent of SIL<sup>34</sup> for the voltage level in question) with the idea that longer lines would be limited by angular displacement rather than voltage drop, but given that the 765 kV system was not (and still is not) fully developed, the equivalent source impedances as viewed by the 765 kV system at the terminals of a 765 kV transmission line may not be negligible with regard to determining the loadability of even longer 765 kV lines, particularly if there are no other 765 kV line branches terminating at the terminal buses in question or the interconnecting facilities are otherwise weak relative to the 765 kV line. It is important to note that the equivalent model of the system external to a single transmission branch is not static, but changes with changes in resource commitment and/or transmission topology. So, any true maximum power transfer limit developed for a single branch (i.e.,  $MPTL_{BranchSystem}$ ) would be dynamic and would change as the external system changes. For this reason, it is generally not feasible to calculate a single true maximum power transfer limit for a transmission branch since it would be very dynamic and would thus change frequently as system conditions change. Instead, the issue of recognizing maximum power transfer limits is generally addressed by performing numerous system studies and simulations such as transient stability studies and/or small signal stability studies using detailed models of facilities and specific system conditions to guard against potential operation at or close to true maximum power transfer limits (which historically have been referred to as steady-state stability limits). In addition, steady-state stability margins are often applied to  $MPTL_{Branch}$  to determine a proxy for the true maximum power transfer limit ( $MPTL_{BranchSystem}$ ) expressed as a percentage of  $MPTL_{Branch}$ . The St. Clair curves discussed in the paper noted above (see footnote 6) were developed using a steady-state stability margin of 30% (which corresponds to an angular displacement between the sending-end and receiving-end voltages of the branch of just over 44°). While current industry practice typically does not establish maximum power transfer limits for individual branches, an alternative practice would be to calculate  $MPTL_{Branch}$  for each impedance branch (a straightforward calculation) and then apply a steady-state stability margin to determine a maximum power transfer screening limit ( $MPTL_{Screen}$ ). The screening limit would then be used as an input in determining the absolute limit. To the extent there are certain branches where this limit is lower than the thermal limits, additional analysis could be performed to determine, on a case-by-case basis, if the system would support a higher maximum power transfer limit, and if so, the absolute rating could be adjusted accordingly. The maximum power transfer screening limit would be calculated as follows:

$$MPTL_{Screen} = (1-SSSM) * MPTL_{Branch} = (1-SSSM) * |V_s| |V_r| / |X_{Br}| \quad (5)$$

Where

$MPTL_{Screen}$  = Maximum Power Transfer Screening Limit in per unit

SSSM = Steady-state Stability Margin in per unit

Maximum Power Transfer Limit of HVDC Lines.

---

<sup>34</sup> SIL = Surge Impedance Loading and is the MW line loading where the reactive power consumed by the distributed series reactance of the line is equal to the reactive power produced by the distributed shunt capacitance of the line, thus there is not net injection or withdrawal of reactive power to or from the line.



Every HVDC line also has a maximum power transfer limit. While the reactance of an HVDC line does not impact steady state operation of the HVDC line, the conductor resistance does impact steady operation of the HVDC line. For power to be transferred in an HVDC line, DC current must flow in the HVDC line conductors. For current to flow in the HVDC line conductors, Ohm's law requires that a voltage difference exist between the sending end terminal and the receiving end terminal of the HVDC line. Assuming there are limits on DC voltage magnitude on an HVDC line of +/- 5% the maximum voltage drop across an HVDC line would be equal to the following:

$$\text{Maximum HVDC Line Voltage Drop} = 1.05 V_N - 0.95 V_N = 0.1 V_N \quad (6)$$

Where

$V_N$  = Nominal HVDC Line-to-Ground Voltage in kV or Per Unit

In this situation, the maximum current flow in an HVDC bi-pole line would be as follows:

$$\text{Maximum HVDC Current Flow} = 0.1 * V_N / R_L \quad (7)$$

Where

$R_L$  = Total resistance of HVDC line conductor in Ohms or per unit

Therefore, the maximum power transfer limit in MW or per unit for an HVDC bi-pole line with nominal voltage  $V_N$  and conductor resistance  $R_L$  would be as follows:

$$\text{Maximum HVDC Power Flow} = 2 * (1.05 * V_N) * (0.1 * V_N / R_L) = 0.21 * V_N^2 / R_L \quad (8)$$

---

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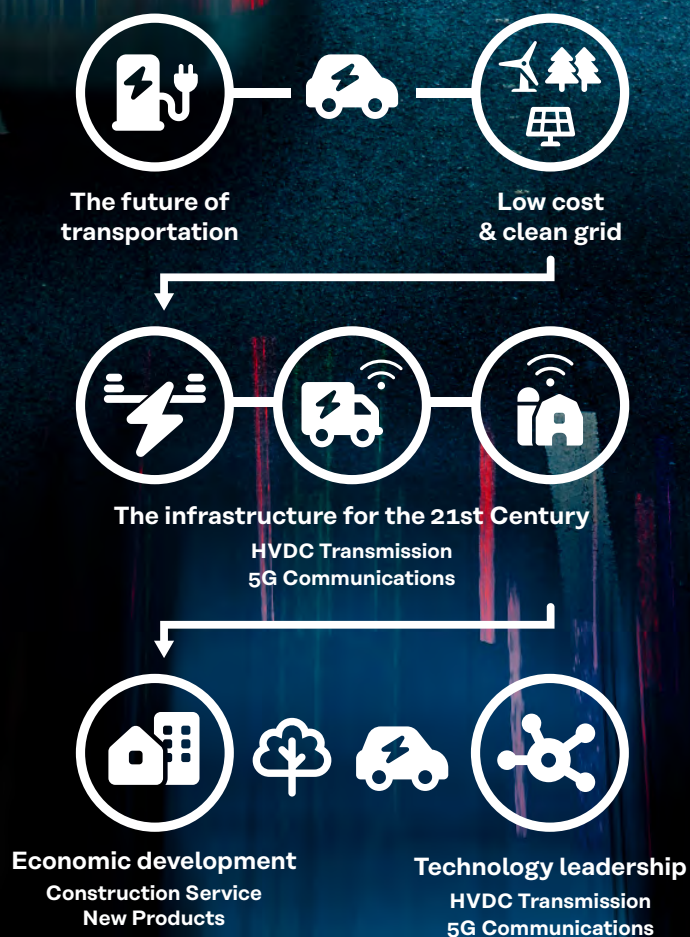


# **NextGen Highways Feasibility Study for the Minnesota Department of Transportation**

## Buried High-Voltage Direct Current Transmission







## Project Team and Project Leads

This white paper was produced by [NGI Consulting](#), [The Ray](#), [Great Plains Institute](#), [Satterfield Consulting](#), [Tracy Warren](#) and [5 Lakes Energy](#).

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The Ray is a 501(c)(3) nonprofit charity and net-zero highway testbed, located on 18 miles of Interstate 85 between LaGrange, Georgia and the Georgia-Alabama state line. The stretch of interstate was named in memory of Ray C. Anderson (1934-2011), a Georgia native recognized as a leader in green business when he challenged his company, Interface, Inc., to pursue a zero environmental footprint. "The Ray Highway" testbed is paving the way for a zero carbon, zero waste, zero death highway system to build a safer and more prosperous future for all.

Learn more at [theray.org](http://theray.org)



## Study Supporters

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# Feasibility Study Documents

To maximize readability of this Feasibility Study while at the same time providing the required deep dives, the Feasibility Study findings are distributed across the series of documents described below. Throughout this Feasibility Study we will use special links to flag the opportunity for interested readers to dive deeper via information in the other Feasibility Study documents.

## **Overview of Relevant Projects**

Content: Compilation of 1-2 page summaries of relevant projects

## **Overview of Federal and State Policy**

Content: Compilation of 1-page summaries of related federal and state policies (Federal Highway Administration, Wisconsin, New Hampshire, & Maine)

## **Related Issue Overviews**

Content: Brief white papers on key topics discussed in the Feasibility Study

- [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#)
- [Minnesota's Energy Future](#)
- [Review of Interregional Transmission Studies](#)
- [Transmission Overview for MnDOT](#)

## **Lessons from Wisconsin**

Content: Documents related to how the Wisconsin Department of Transportation (WisDOT) and the Public Service Commission of Wisconsin (PSCW) work together to site transmission in highway right-of-way

- [Introduction to Permitting Transmission in WisDOT Right-of-Way](#)
- [Wisconsin 2003 Act 89](#)
- [Wisconsin DOT Utility Accommodation Policy \(2020\)](#)
- [Cooperative Agreement between WisDOT and PSCW Regarding New Electric Transmission Lines \(2009\)](#)
- [Utility Constructability Report for Badger Coulee Transmission Line \(2013\)](#)
- [Badger Coulee Transmission Line Final Environmental Impact Statement \(2014\)](#)
- [Wisconsin DOT Permit for Utility to Construct, Operate and Maintain Utility Facilities on Highway Right-of-Way \(2016\)](#)

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# Executive Summary

## Abstract

The NextGen Highways Team worked with an internal working group at the Minnesota Department of Transportation (MnDOT) to investigate the opportunities and barriers associated with locating buried high-voltage direct current (HVDC) transmission and fiber within the highway right-of-way (ROW). This Feasibility Study reviewed applicable policy, regulation, and projects; analyzed MnDOT-specific concerns; examined HVDC transmission line requirements; assessed buried HVDC cost and benefits; and broadly evaluated typical highway ROW design for suitability of HVDC transmission line siting. The findings from this study demonstrate that buried HVDC transmission is cost-effective and can be feasibly sited in interstate and highway ROW after making appropriate consideration for existing and future transportation system needs. While the team identified challenges over the course of this study, none of those challenges appear to pose barriers that cannot be overcome.

## The NextGen Highways Vision for Integrated Infrastructure

NextGen Highways are highways where electric and communications infrastructure are strategically co-located in the highway right-of-way.

NextGen Highways would accomplish the following:



**build for our transportation future** by integrating electric and communications infrastructure into our existing transportation infrastructure



**enable a clean energy economy** by building the transmission needed to affordably achieve 100 percent clean energy and by ensuring the electric grid can be rapidly strengthened in transportation corridors to support electric vehicle charging needs



**unleash economic development** by removing barriers that are currently holding back a trillion dollars of private investment that would create new jobs, services, and technologies



**strengthen national security** by constructing an energy and communications backbone that is hardened against everything from severe weather events to cyberattack



**improve equity** by remedying the enduring air quality impacts of the interstate system, which disproportionately affect low-income communities and Black, Indigenous and people of color communities, and by increasing broadband access in rural and urban communities

## Purpose and Need

Hundreds of billions of dollars are now being invested in electric, connected, and autonomous vehicles.<sup>1</sup> To fully support these vehicles, our existing transportation infrastructure will need to evolve to incorporate electric and communications infrastructure. This evolution is required to power these vehicles and the communications infrastructure to support their connected and autonomous functionality. In short, our existing transportation, communications and electric infrastructure will need to become integrated.<sup>2</sup>

From the perspective of a state department of transportation (DOT), there are several key challenges and opportunities related to the future of transportation and integrated infrastructure:

| Challenge                                                                                                         | Opportunity                                                                                                                                                                                                                                                                              |
|-------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Transportation electrification of fleets will require extensive electric upgrades in highway corridors            | Enable the required electric grid upgrades by providing electric utilities with highway ROW access for buried transmission or distribution                                                                                                                                               |
| Transportation decarbonization requires electrification and grid decarbonization                                  | Enable the construction of the long-distance transmission lines needed for cost-effective grid decarbonization to benefit transportation                                                                                                                                                 |
| Reducing vehicle miles traveled                                                                                   | Improve broadband access using DOT ROW such that remote work, online learning, and some professional services (e.g. telehealth) can help reduce the number of vehicle miles traveled                                                                                                     |
| Maximizing the positive impacts and mitigating the negative impacts of the highway system to adjacent communities | Use the transportation system to (1) deliver community benefits (e.g., broadband); (2) reduce air pollution (by supporting the electric grid investments needed to accelerate the transition to EVs); and (3) reduce the private land acquisition needed to accommodate new transmission |

<sup>1</sup> [The future of mobility is at our doorstep](#)

<sup>2</sup> [Our Transportation Future: Industries Collide](#)

Federal policy and funding for integrated infrastructure has just started to emerge. In April 2021, the White House announced a coordinated set of actions by the US Department of Energy and the US Department of Transportation that would encourage the development of “Clean Energy and Connectivity” projects along the nation’s highway system.<sup>3</sup>

## Study Background and Scope

In June 2020, MnDOT established a Sustainable Transportation Advisory Council (STAC) to help MnDOT reduce transportation carbon emissions. As part of its first set of recommendations to MnDOT in December 2020, the STAC recommended that MnDOT examine the value of NextGen Highways.<sup>4</sup> The STAC’s recommendations included asking MnDOT to update its utility accommodation policy and initiate a multi-stakeholder process focused on NextGen Highways.

In its April 2021 response to the STAC recommendations, MnDOT committed to working with the NextGen Highways Team and other stakeholders to clarify opportunities and challenges to co-locate broadband and electric transmission in interstate and highway ROW.<sup>5</sup>

From June through December 2021, the NextGen Highways Team and associated partners worked with an internal working group at MnDOT to investigate the opportunities and barriers associated with locating buried HVDC transmission and fiber within highway ROW. The key findings from this analysis, which focuses on buried HVDC transmission, and next steps are presented below.

Items addressed in this Feasibility Study include:

- Policy review
  - Review of federal policy and funding related to integrated infrastructure
  - Review of Minnesota and MnDOT policies, plans, and regulations
  - Review of key policies in select other states
- Project review
  - Review of relevant projects in the US and Europe
- Analysis of MnDOT concerns
  - Covered 14 different topic areas: safety, highway expansion and maintenance, planning and siting, permitting, and license fees
- Buried HVDC transmission—introduction for DOTs
  - Introduction to system design and footprint, safety, construction techniques, maintenance requirements, and potential impacts on existing infrastructure and the environment
- Buried HVDC transmission—requirements
  - Planning, siting, permitting, construction, maintenance, and future relocation

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<sup>3</sup> [FACT SHEET: Biden Administration Advances Expansion & Modernization of the Electric Grid Our Transportation Future: Industries Collide](#)

<sup>4</sup> [Sustainable Transportation Advisory Council \(STAC\) Recommendations to MnDOT](#)

<sup>5</sup> [MnDOT Response: 2020 Sustainable Transportation Advisory Council Recommendations](#)

- Buried HVDC transmission—cost and benefits
  - Cost comparison: buried HVDC vs. overhead AC
  - Grid reliability and resiliency benefits
  - Societal value of accelerated permitting and siting
- Broad assessment of feasibility

## MnDOT Findings

The MnDOT Work Group and NextGen Highways team identified areas where further study and resolution of specific issues are required for MnDOT to consider supporting longitudinal siting of buried HVDC transmission and fiber in interstate ROW. Utility siting in uncontrolled highway ROW is already allowed in Minnesota. A more detailed evaluation of these topics is provided in Part 1a and Part 1b of this report.

**Table 1. Considerations for longitudinal siting of HVDC transmission and fiber in the interstate right-of-way**

| Topic                                                        | Description                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
|--------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Current MN Policy</b>                                     | <p>Longitudinal utility installation is <b><i>not</i></b> allowed in Minnesota Interstate and other Controlled Access Highways.</p> <p>MnDOT, Minnesota Public Utilities Commission (MN PUC), and the Minnesota Department of Commerce (Commerce) already coordinate to site proposed transmission lines just outside the ROW. This process can be built upon for siting transmission in ROW.</p> <p>A Dig Once policy has been enacted for broadband conduit.</p> |
| <b>Regulatory Landscape Outside of MN</b>                    | <p>Some states (WI, NH, ME) allow longitudinal siting of transmission lines in the highway and interstate ROW.</p> <p>The Federal Highway Administration (FHWA) is encouraging state DOTs to allow co-location of fiber, electrical transmission and distribution, and renewable energy in the highway and interstate ROW.<sup>6</sup></p>                                                                                                                         |
| <b>Safety</b>                                                | <p>Safety features for HVDC lines include the following: (1) burying underground, (2) surface and subsurface markings, (3) restricted access, (4) thick cable insulation, (5) conduit, (6) cable shield ground points, and (7) adherence to MnDOT's Utility Accommodation Manual (UAM) for permitting, construction, environmental restoration, and traffic control.</p>                                                                                           |
| <b>Policy/Plan Alignment</b>                                 | <p>There is significant alignment between the NextGen Highways vision and Minnesota and MnDOT's existing goals, policies, and strategic plans.</p>                                                                                                                                                                                                                                                                                                                 |
| <b>Overhead Infrastructure &amp; HVDC Converter Stations</b> | <p>A buried HVDC transmission line would not have any aboveground infrastructure located in the ROW. Associated HVDC converter stations would be placed well outside of the ROW.</p>                                                                                                                                                                                                                                                                               |

<sup>6</sup> [State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance](#)

| Topic                                                                | Description                                                                                                                                                                                                                                                                                                                                                                                                                  |
|----------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Potential HVDC Operational Impacts on Existing Infrastructure</b> | Buried HVDC transmission lines do not induce currents or create voltage potentials, do not affect nearby communication infrastructure or equipment, and do not corrode adjacent metal pipes. HVDC converter stations could interfere with communication infrastructure but are designed not to via the use of a faraday cage.                                                                                                |
| <b>Environmental Impacts</b>                                         | <p>Buried HVDC transmission lines have significantly less impact on the environment than overhead transmission lines.</p> <p>Transmission lines would be subject to environmental requirements in MnDOT's Utility Accommodation Policy and MN PUC's transmission siting process.</p>                                                                                                                                         |
| <b>Future Highway Maintenance &amp; Construction</b>                 | MnDOT must be able to maintain and expand the highway ROW as needed to serve Minnesota's transportation needs. Non-transportation infrastructure must not unreasonably impede highway maintenance and expansion.                                                                                                                                                                                                             |
| <b>Planning &amp; Siting Utilities in the ROW</b>                    | <p>When siting a buried HVDC transmission line or major fiber line, the goal is to place it where it won't have to move (for as long as possible).</p> <p>Increased density of utilities in urban areas and the difficulty of accurately locating existing utilities have led to operational challenges.</p> <p>There is a need for more integrated planning.</p>                                                            |
| <b>Transmission Permitting</b>                                       | MnDOT has jurisdiction in its ROW and must approve any transmission project. MnDOT has a transmission permitting process for utility crossings that can be built upon for siting transmission in ROWs.                                                                                                                                                                                                                       |
| <b>Transmission Construction</b>                                     | Construction methods, traffic impacts, and safety considerations all must be accounted for and mitigated.                                                                                                                                                                                                                                                                                                                    |
| <b>Transmission Maintenance</b>                                      | Access to highway ROW presents both safety and security concerns. Modern HVDC transmission lines require minimal maintenance (namely, annual visual inspections). No new security vulnerabilities for MnDOT have been identified.                                                                                                                                                                                            |
| <b>Future Utility Relocation Responsibilities and Costs</b>          | State statute specifies that MnDOT is responsible for all utility relocation costs for utilities located in the interstate ROW. This is contrary to the assignment of relocation costs to the utility for highway ROW in Minnesota and contrary to the policies of many other states. The assignment of utility relocation costs to MnDOT is a barrier to the use of interstate ROW for buried transmission or buried fiber. |
| <b>Permit Fees and Utility Leasing Fees</b>                          | MnDOT does not currently charge permit fees or utility license fees for use of its ROW. This poses a financial concern for MnDOT as transmission and fiber build-out in the ROW would increase the amount of required coordination between MnDOT and utilities, consequently requiring more internal MnDOT resources.                                                                                                        |



| Topic                                | Description                                                                                                                                                                                                                                                                                                                                                                    |
|--------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Communications Infrastructure</b> | <p>There are strong parallels between buried fiber and transmission for siting and construction in an existing ROW.</p> <p>Minnesota IT Services (MNIT) can barter existing fiber with the private sector. This exchange of fiber resources has reduced public network costs and benefited private sector companies in the network services they provide across the state.</p> |

## Recommended Next Steps in Minnesota

Based on the findings noted above, the following are recommended next steps to further evaluate and advance the NextGen Highways vision in Minnesota.

**Table 2: Recommended next steps to advance NextGen Highways in Minnesota**

| Topic(s)                                                       | Description                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
|----------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>MN Policy &amp; Permitting</b>                              | <p>The NextGen Highways Team and MnDOT review Wisconsin's laws, policies, and processes that have enabled the location of overhead AC transmission and fiber in interstate and highway ROW.</p> <p>MnDOT, with support from the NextGen Highways Team, examines how to remove barriers that exist in state statute, MnDOT rules, and MnDOT's utility accommodation policy (e.g., assignment of interstate utility relocation costs to MnDOT). This would include the engagement of other state agencies such as Commerce and MN PUC.</p> <p>The NextGen Highways Team and MnDOT further evaluate potential impacts on vegetation, noxious weeds, wetlands, slope stabilizers, stormwater management, cultural resources, and tribal lands.</p> |
| <b>Transmission: Construction, Maintenance, and Relocation</b> | <p>The NextGen Highways Team and MnDOT further investigate transmission construction, maintenance, and relocation processes, taking lessons from project "Constructability Reports" and maintenance agreements in Wisconsin and incorporating knowledge specific to buried HVDC transmission lines.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| <b>Planning and Siting</b>                                     | <p>The NextGen Highways Team, with support from MnDOT, conducts a GIS review of the suitability of MnDOT's ROW for buried HVDC transmission and fiber.</p> <p>The NextGen Highways Team, with support from MnDOT, conducts a high-level evaluation of a buried HVDC transmission and fiber project in an interstate or highway corridor that would address known transmission needs (e.g., needs identified by MISO's long-range transmission planning process).</p> <p>MnDOT, with support from the NextGen Highways Team, examines potential to reduce existing process barriers (e.g., challenges with the current utility locate process).</p>                                                                                             |

| Topic(s)                             | Description                                                                                                                                                                                                                                                                                                              |
|--------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Communications Infrastructure</b> | The NextGen Highways Team and MnDOT expand the focus of the work to include fiber and communications infrastructure and support MnDOT as it seeks to clarify (1) its fiber needs to support connected and autonomous vehicles, and (2) fiber needs to support improved broadband access in communities across the state. |
| <b>Stakeholder Engagement</b>        | The NextGen Highways Team and MnDOT engage a greater number of stakeholders outside of MnDOT (e.g., state agencies, utilities, tribes, communities, cities, and companies).                                                                                                                                              |

## National Findings

**The following findings demonstrate that buried HVDC transmission is cost-effective and can be sited in interstate and highway ROW through appropriate consideration of transportation system needs.**

1. Transmission and fiber have been and are being sited in interstate and highway ROW across the United States.
2. Much of the interstate is suitable for buried HVDC transmission and fiber, but certain areas require special considerations or routing outside of the interstate ROW.
3. Buried HVDC transmission can be compatible with interstate and highway ROW.
4. Buried HVDC transmission is comparable in cost to overhead AC transmission while providing additional reliability and resilience benefits.
5. Together, DOT ROW and buried HVDC transmission can deliver billions of dollars in societal benefits.
6. Buried HVDC transmission supports transportation decarbonization.
7. Wisconsin has the playbook for siting transmission in DOT ROW.

## National Recommendations

### State DOTs should:

- Site and build fiber in a way that allows for buried HVDC transmission to be co-located at a later date
- Develop and invest in their relationship with utilities, public utilities commissions, and other state agencies with transmission siting jurisdiction
- Determine the amount of operational funding required to support the co-location of electric and communications infrastructure in their ROW

### Utilities and energy developers should:

- Develop and invest in their relationship with state DOTs
- Evaluate how highway ROW (if made available) could enable the various grid investments needed to support electric vehicle charging
- Evaluate how planned regional and interregional transmission lines could benefit from highway ROW (if made available)

### Governors should consider:

- Supporting and facilitating the implementation of Wisconsin's co-location playbook
- Working with their DOT, utilities, and legislature to remove any statutory barriers in state law
- Evaluating options to provide their DOT with operational funding to support the co-location of electric and communications infrastructure in the ROW

## Next Step for NextGen Highways

Given the positive findings from this Feasibility Study, the NextGen Highways Team is planning to launch a NextGen Highways Coalition to support the co-location of buried fiber and transmission in highway and interstate ROW.

The NextGen Highways Coalition will do the following:

- Facilitate conversations between state DOTs, utilities, and governors
- Facilitate conversations between state DOTs, utilities, and technology vendors
- Review states' highway ROW siting and permitting regulations, identify barriers to co-location, and work with stakeholders to overcome barriers
- Share insights and best practices across states
- Provide a platform through which tribes, communities, nonprofits, cities, and companies can understand the required transformation of the national highway system
- Foster public/private partnerships to build out the required infrastructure

Interested parties can email [morgan@buildngi.com](mailto:morgan@buildngi.com) and [laura@theray.org](mailto:laura@theray.org) for more information.

## Conclusion

The findings from this study demonstrate that buried HVDC transmission can be cost-effective and that there is the potential to be sited in Interstate and highway ROW after making appropriate consideration of existing and future transportation system needs. Next steps are proposed to address the challenges identified over the course of this study.

Buried fiber in the interstate and highway ROW shares many of the same challenges as buried HVDC transmission. Given the ability of state DOTs to co-locate buried fiber and HVDC transmission, it makes sense for them to consider the potential for future accommodation of buried HVDC transmission when installing fiber in interstate and highway ROW.



## Feasibility Study Documents

Results from the Feasibility Study are distributed across a series of documents. The primary document is the Study Report. Additional documents include an Overview of Relevant Projects, an Overview of Federal and State Policy, Overviews of Related Issues (a series of documents), and Lessons from Wisconsin (a series of documents). These additional documents are flagged from within the Study Report and provide interested readers an opportunity to dive deeper into an issue than practical within the Study Report.

# Study Preface: A Changing Transportation Landscape

## The Future of Transportation Requires Integrated Infrastructure

Hundreds of billions of dollars are now being invested in electric, connected, and autonomous vehicles.<sup>7</sup> Our existing transportation infrastructure will need to evolve to incorporate the electric infrastructure to power these vehicles and the communications infrastructure to support their connected and autonomous functionality. In short, our existing infrastructure will need to become integrated.<sup>8</sup>

From the perspective of a state department of transportation (DOT), there are several key challenges and opportunities related to the future of transportation and integrated infrastructure:

| Challenge                                                                                                         | Opportunity                                                                                                                                                                                                                                            |
|-------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Transportation electrification of fleets will require extensive electric upgrades in highway corridors            | Enable the required electric grid upgrades by providing electric utilities with ROW access for buried transmission and/or distribution                                                                                                                 |
| Transportation decarbonization requires electrification <i>and</i> grid decarbonization                           | Enable the construction of the long-distance transmission lines needed for cost-effective grid decarbonization                                                                                                                                         |
| Reducing vehicle miles traveled                                                                                   | Improve broadband access using DOT ROW such that remote work, online learning, and some professional services (e.g. telehealth) can help reduce the number of vehicle miles traveled                                                                   |
| Maximizing the positive impacts and mitigating the negative impacts of the highway system to adjacent communities | Use the transportation system to (1) deliver community benefits (e.g., broadband); (2) reduce air pollution (by supporting the electric grid investments needed to accelerate the transition to EVs); and (3) reduce the need for new transmission ROW |

<sup>7</sup> [State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance](#)

<sup>8</sup> [Our Transportation Future: Industries Collide](#)

## Federal Policy and Funding for Integrated Infrastructure

Federal policy and funding for integrated infrastructure has just started to emerge. In April 2021, the White House announced a coordinated set of actions by the US Department of Energy and the US Department of Transportation that would encourage the development of “Clean Energy and Connectivity” projects along the United States highway system.<sup>9</sup> These and related actions include the following:

### FHWA Guidance Memo (April 2021)

Clarified that highway ROW “can be leveraged by State DOTs for pressing public needs relating to climate change, equitable communications access, and energy reliability.” Examples of projects listed include energy generation, electrical transmission and distribution projects, broadband projects, vegetation management, inductive charging in travel lanes, and alternative fueling facilities.<sup>10</sup>

### DOE Loan Program Announcement (April 2021)

Announced that the Loan Program Office is seeking applications for up to \$5 billion in loan guarantees to support innovative transmission projects. This includes high-voltage direct current (HVDC) systems, transmission to connect offshore wind, and facilities sited along rail and highway routes.<sup>11</sup>

### Investment in Infrastructure and Jobs Act (IIJA) (November 2021)

Made undergrounding of public utility infrastructure eligible under the National Highway Performance Program if carried out in conjunction with an eligible project.<sup>12</sup>

### FHWA Rulemaking (December 2021)

FHWA amended its regulations governing the accommodation of utilities to implement requirements of the Consolidated Appropriations Act of 2018 for broadband infrastructure deployment.<sup>13</sup>

For more information, please see the [Overview of Federal and State Policy](#) document.

## An Expanding Definition of Transportation

Coincidental with the growing recognition of the need for integrated infrastructure, DOTs are increasingly taking or being asked to take an expanded view on the definition of transportation.

As the following excerpt from the Wisconsin Department of Transportation (WisDOT) guide to utility coordination shows, WisDOT is open to the accommodation of utility infrastructure in its interstate and highway ROW and understands it has a role to play in helping to minimize costs for the general public:

The 1979 Edition of the Random House Dictionary of the English Language defines transportation as “the business of conveying people, goods, etc.” WisDOT is charged with providing an efficient, safe, and economical transportation system for the people and goods in the state of Wisconsin.

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<sup>9</sup> [FACT SHEET: Biden Administration Advances Expansion & Modernization of the Electric Grid](#)

<sup>10</sup> [State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance](#)

<sup>11</sup> [Loans Will Support Projects to Widen Clean Electricity Reach and Enhance Grid Reliability](#)

<sup>12</sup> [FACT SHEET: Biden Administration Advances Expansion & Modernization of the Electric Grid](#)

<sup>13</sup> [Federal Highway Administration 23 CFR § 645](#)

The funding for our work comes largely from State and Federal taxes, which are paid by the general public. A utility company's primary source of revenue is the rates paid by the consumers, which are, in effect, the general public. In order to reduce the total cost to the general public, the designer must plan the proposed work so that the cost of relocating utility facilities, and the cost of the highway project are minimized. This provides a facility with the lowest overall transportation cost.<sup>14</sup>

Similarly, in Utah, HB 333 proposes to transfer Utah's Broadband Center—responsible for expanding broadband access and usage across Utah—to the Utah Department of Transportation.<sup>15</sup>

In Texas, Senate Bill 507 ruled for the Texas Transportation Commission to establish an accommodation process that authorizes broadband-only providers to use the state highway ROW for creating, maintaining, making additions to, and relocating both new and existing broadband facility installations in the ROW.<sup>16</sup>

Finally, in the words of one staff member from the Minnesota Department of Transportation (MnDOT):

***“Teleworking has proven itself a way of transportation; [I] now consider this a transportation issue.”***

## The NextGen Highways Vision for Integrated Infrastructure

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NextGen Highways would accomplish the following:



**build for our transportation future** by integrating electric and communications infrastructure into our existing transportation infrastructure



**enable a clean energy economy** by building the transmission needed to affordably achieve 100 percent clean energy and by ensuring the electric grid can be rapidly strengthened in transportation corridors to support electric vehicle charging needs



**unleash economic development** by removing barriers that are currently holding back a trillion dollars of private investment that would create new jobs, services, and technologies



**strengthen national security** by constructing an energy and communications backbone that is hardened against everything from severe weather events to cyberattack



**improve equity** by remedying the enduring air quality impacts of the interstate system, which disproportionately affect low-income communities and Black, Indigenous and people of color communities, and by increasing broadband access in rural and urban communities

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<sup>14</sup> [Wisconsin Department of Transportation Guide to Utility Accommodation, Chapter 1](#)

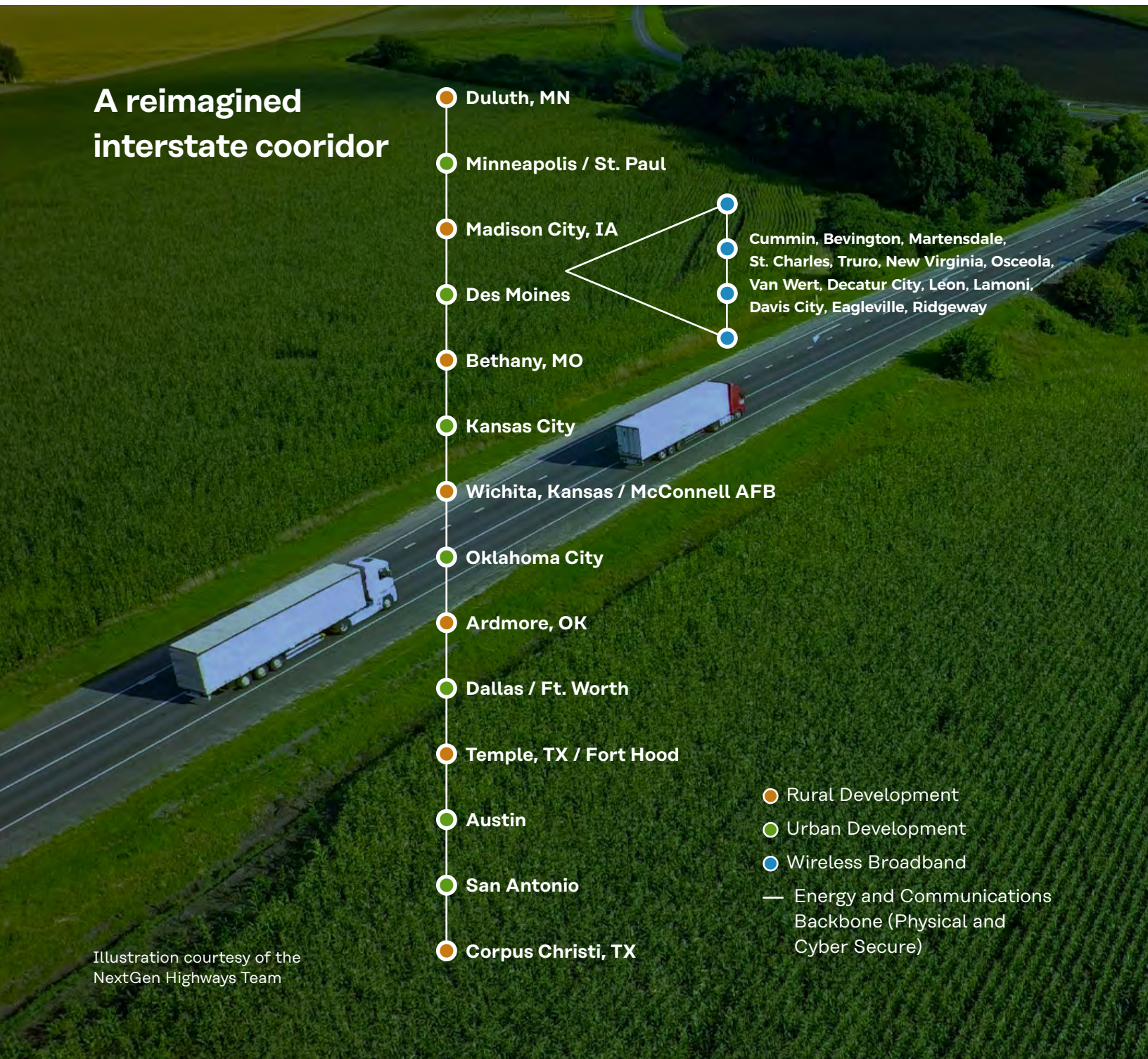
<sup>15</sup> [Utah State Legislature, H.B. 333, Economic and Workforce Development Amendments](#)

<sup>16</sup> [Texas Senate, SB 507, Legislative Session 87\(R\)](#)



As illustrated in figure 1, showing a reimagined interstate corridor, **NextGen Highways would create an energy and communications backbone that would drive economic development in rural and urban areas.**

**Figure 1. A reimagined interstate corridor where energy and communications infrastructure support economic development and increase resilience.**





**In rural areas**, economic development and resilience centers would be focused on data centers, energy resources (e.g., solar, wind and storage), and over-the-road charging of electric vehicles.

**In urban areas**, economic development and resilience centers would support fleet electrification, re-development of retired generation assets (including their transmission infrastructure), data centers and energy resources.

**Throughout the interstate corridor**, NextGen Highways would deliver wireless broadband services to communities adjacent to the highways and would support the operation of connected and autonomous vehicles.

Critically, this energy and communications backbone would be hardened against physical and cyberattacks, allowing it to operate as a provider of last resort in the event of an attack on our existing electric grid and communications infrastructure.

For more information on the NextGen Highways concept, please see the NextGen Highways white paper.<sup>17</sup>

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<sup>17</sup> NextGen Highways: Co-locating the Transport of Vehicles, Energy and Information

# Study Introduction:

## Why the Focus on Buried HVDC Transmission?

### Study Background and Scope

#### Study Background

In June 2020, MnDOT established a Sustainable Transportation Advisory Council (STAC) to help the agency reduce transportation carbon emissions. As part of its first set of recommendations to MnDOT, the STAC recommended that MnDOT examine the value of NextGen Highways.<sup>18</sup> The STAC's recommendation included asking MnDOT to update its utility accommodation policy and initiate a multi-stakeholder process focused on NextGen Highways.<sup>19</sup>

In its response to the STAC recommendations, MnDOT committed to working with the NextGen Highways Team and other stakeholders to clarify opportunities and challenges to co-locate broadband and electric transmission in interstate and highway ROW.<sup>20</sup>

MnDOT chose to participate in the further evaluation of NextGen Highways as it saw the potential for greater utilization of the ROW to support a number of internal and state goals: transportation electrification; electric grid decarbonization; preparing for connected and autonomous vehicles; increasing broadband access; and grid reliability and security. Each of these is an envisioned component of NextGen Highways.<sup>21</sup>

#### Study Scope

This Feasibility Study is the first product resulting from MnDOT's further evaluation of the NextGen Highways vision. The study was focused on examining the feasibility of allowing a utility to install a new type of transmission technology—buried HVDC transmission within the highway ROW.

The overarching goal of the Feasibility Study was to determine whether the potential for locating buried HVDC transmission in MnDOT ROW was sufficiently promising to merit further investigation.

Secondary study goals included the following:

- identification of co-location barriers and opportunities for further study
- survey of allowed ROW uses in other US states
- clarification of buried HVDC transmission costs and benefits

Notably, the Feasibility Study consists of two parts. The first part of the study focused on evaluating MnDOT's specific questions surrounding the potential installation of buried HVDC transmission in its interstate and highway ROW. The key result from part one was the identification of MnDOT-specific barriers and opportunities related to the potential installation of buried HVDC transmission in MnDOT ROW.

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<sup>18</sup> [Sustainable Transportation Advisory Council \(STAC\) recommendations to MnDOT](#)

<sup>19</sup> [NGI Consulting presented the NextGen Highways vision and 2020 white paper to the STAC in October 2020](#)

<sup>20</sup> [MnDOT Response: 2020 Sustainable Transportation Advisory Council Recommendations](#)

<sup>21</sup> NextGen Highways: Co-locating the Transport of Vehicles, Energy, and Information

The second part of the study had a broader focus. It included examining allowed utility access to DOT ROW in other states and investigating the cost and benefits of buried HVDC transmission. The key result from the second part was a clear understanding of existing precedent in other states and a rough sense of the economic feasibility of installing buried HVDC transmission in highway ROW.

### Why Start with Buried HVDC Transmission?

The reason to start with a focus on buried HVDC transmission is simple: it is a transmission technology that can be and is being sited within existing transportation ROW. As such, there is a need for MnDOT and other state DOTs to be aware of this new type of utility that may seek accommodation in interstate or highway ROW through a state DOT's existing utility accommodation policy.

Proposed projects in the US and Europe provide clear examples of transmission developers combining buried HVDC transmission technology with existing transportation rights-of-way. The proposed project examples in the US are the SOO Green HVDC Link, Clean Path NY, and Champlain Hudson Power Expressway. In Europe, the examples are the SuedLink, SuedOstLink, and Italy-France Interconnector.

Figure 2 shows four buried HVDC cables that have been sited within the A-32 motorway as part of the Italy-France Interconnector. Notably, this project required amending the highway code. It was one of the first times that underground transmission was longitudinally sited in a motorway in France.<sup>22</sup>

**Figure 2. Buried HVDC cables in highway ROW (Italy-France Interconnector)**



Photo courtesy of Roda S.p.A.

<sup>22</sup> [Savoie-Piémont: 190 km of European Solidarity from Chambéry to Turin](#)



It is worth noting that buried HVDC projects often combine a number of different types of ROW (existing and new): existing highway, railway, and waterway ROWs are commonly used. As one example, the proposed SOO Green HVDC link uses both highway and railway ROW despite being known predominantly for its use of railway ROW.

For two-page project summaries for each of the buried HVDC projects referenced above, please see the [Overview of Relevant Projects](#) document.

### **Buried HVDC Transmission Also Matters to DOTs**

As a final note, buried HVDC transmission doesn't just matter to the electric utility industry – it also matters to the transportation industry.

Buried HVDC transmission matters to DOTs and the transportation industry because it will directly support transportation electrification and decarbonization. The three different ways that buried HVDC transmission will do this are described in detail in [Finding #6: Buried HVDC transmission supports transportation decarbonization](#).

# Buried HVDC Transmission: A Brief Introduction for DOTs

In seeking to understand the feasibility of locating buried HVDC transmission within interstate and highway ROW, MnDOT had a number of questions related to the following areas:

- system design and footprint
- safety
- transmission construction techniques
- transmission maintenance requirements
- potential impact on existing infrastructure and devices
- environmental impacts

The NextGen Highways team investigated these questions and produced an [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#) document that discusses each of the areas above to help MnDOT (and other state DOTs) evaluate the compatibility of buried HVDC transmission within highway and interstate ROW. Notably, the NextGen Highways team's investigation and projects under development in Europe suggest that buried HVDC transmission can be compatible with interstate and highway ROW.<sup>23</sup>

Key takeaways from the [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#) document are presented below for each of the areas identified above.

## System Design and Footprint

There are three primary components of a buried HVDC transmission line. The conductor, or cable, is buried below grade and requires a 5-foot ROW for construction. Conductor sections are connected approximately every half mile inside joint vaults, which are typically 40 feet long, 10 feet wide, and 8 feet tall and buried fully below grade. Lastly, converter stations are above ground but located fully outside the highway ROW. These primary components and their relative locations are shown in figure 3.

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<sup>23</sup> As discussed in Finding #2, there are certain areas where it will not be practical to site buried HVDC transmission in the interstate or highway ROW. But the existence of specific constraints doesn't prevent the broader use of the interstate and highway ROW.

**Figure 3. Schematic of buried HVDC transmission line in highway right-of-way**

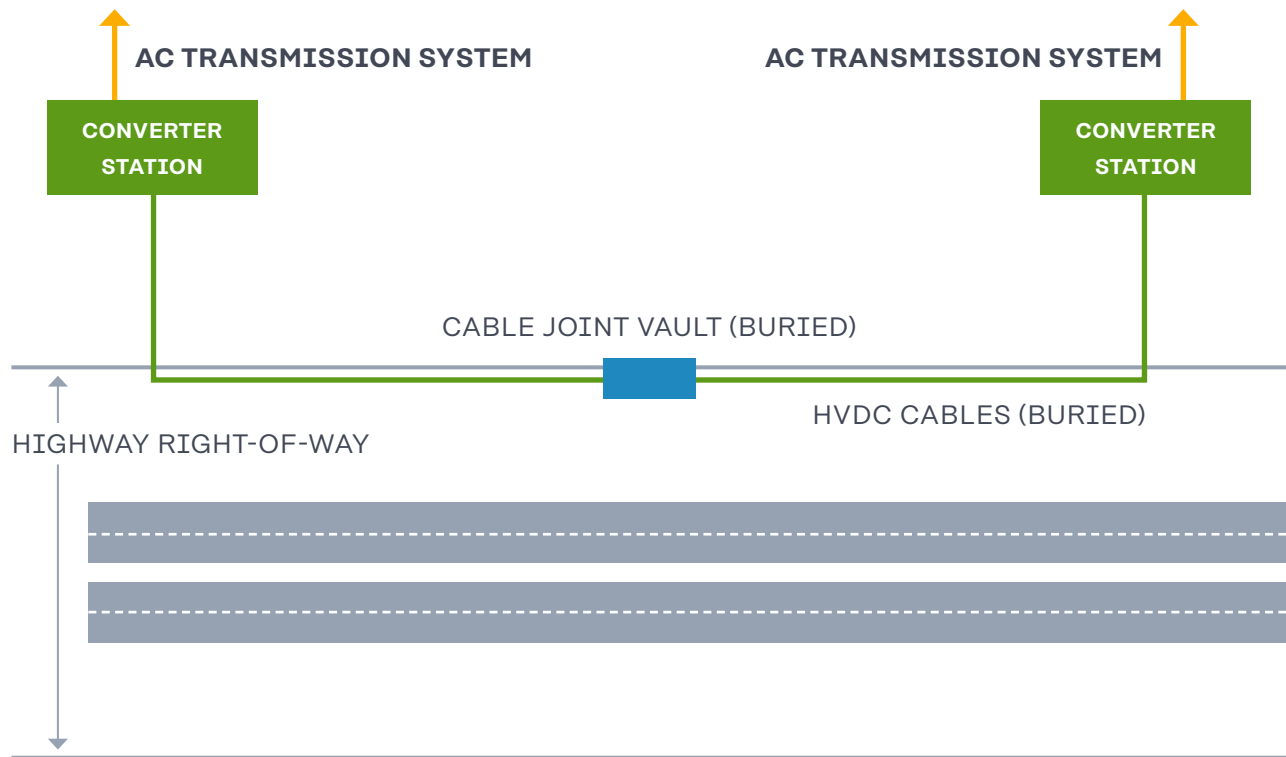


Figure developed by the NextGen Highways Team

Figure 4 provides a cross-section view of one buried cable design. It shows that while the transmission cable requires a 5-foot wide ROW, the cables are about 5 inches in diameter. This leaves space for co-location with other utilities (i.e., fiber optic cables) within the same 5-foot ROW.

**Figure 4. Cross-section of a buried HVDC cable**

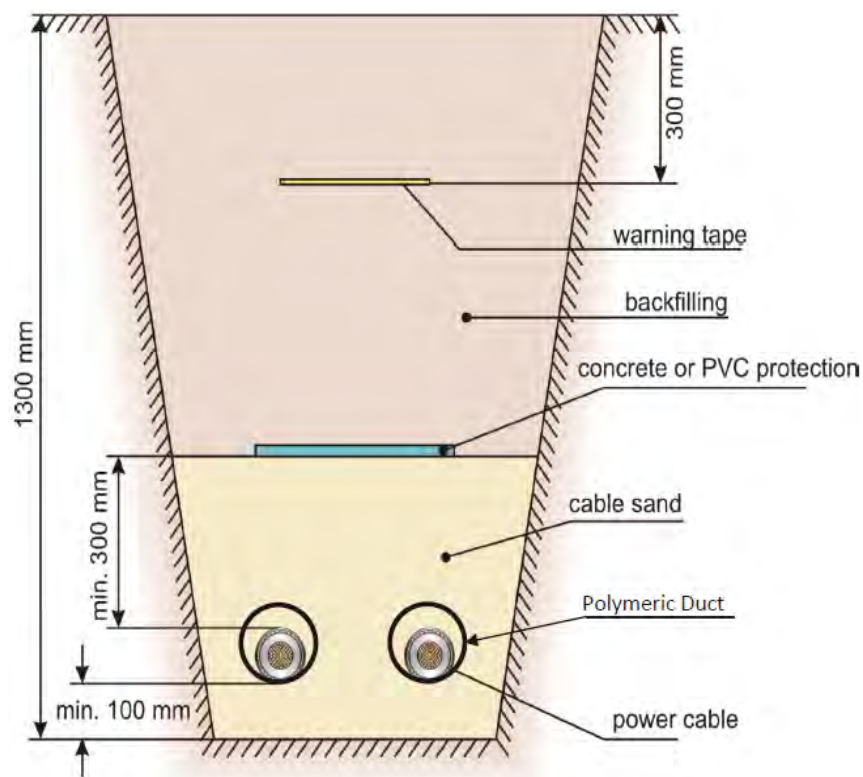
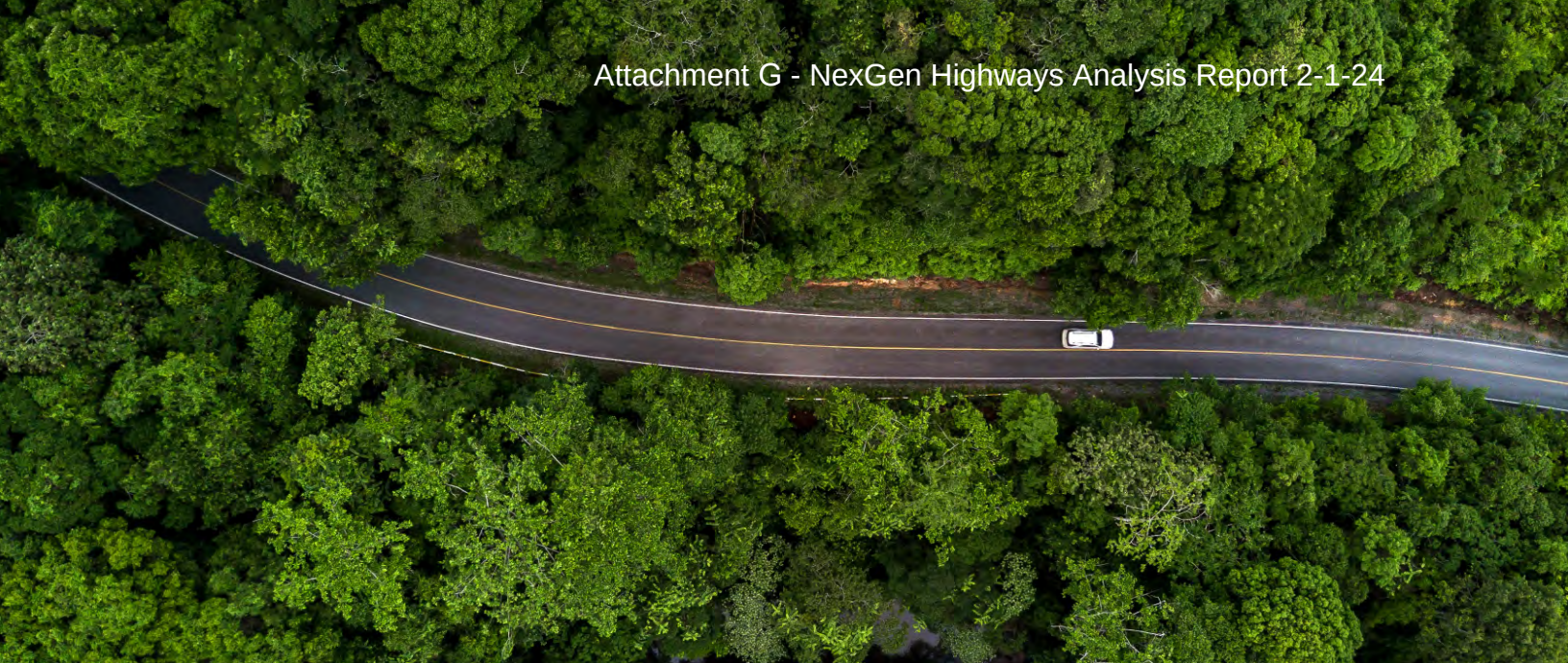


Figure courtesy of Southwire



### **Buried HVDC transmission safety considerations**

Safety is a key concern for both project developers and DOTs for any utility infrastructure in the highway ROW. Several protection schemes are put in place along the entire length of the buried cable. A warning tape is laid down approximately one foot below grade along the entire length of the cable path. Below this warning tape, approximately three feet deep and one foot above the cables, a concrete or PVC proactive layer is placed to mitigate and protect against dig-in risk. Then, depending on the design choices of the specific project, additional protection can be implemented around the cables.

One example of a design with additional protection is the buried duct installation (see figure 4), in which a polymeric duct is placed in the trench along the length of the line. Then the cable is pulled through that duct. This provides additional protection for the cable and has the added benefit of providing additional security against theft during construction and protection against dig-ins after construction is complete.

Lastly, a duct bank system can be employed, encapsulating the cable ducts into a concrete bank. This system provides additional protection against dig-ins compared to the direct buried cable or buried duct approaches.

### **Buried HVDC Transmission Construction**

During construction, a number of techniques can be employed to efficiently and safely lay cable and associated protective equipment. In open or rural areas, open trenches can be dug to lay cables in, then buried with native or thermal backfill, depending on the specific project design needs. In more confined areas or those with obstacles like waterways or other communications or transportation infrastructure, specialized equipment can be used to simultaneously dig the trench, lay the cable, and cover it with backfill. Where needed, horizontal drilling techniques can be employed to tunnel under waterways or avoid disturbing the surface of the ROW.



## **Buried HVDC Transmission Maintenance**

Modern HVDC transmission line designs require minimal ongoing maintenance over their expected 40-year useful life. Modern cables use cross-linked polyethylene insulation that does not require any cooling oil or oil pumping stations to maintain safe operation. Transmission line operators may elect to perform visual inspections of the cable joint vaults annually. Any other equipment that would need regular maintenance is located outside the highway ROW.

## **Impact on Existing Utilities and Infrastructure in the Highway ROW**

Buried HVDC transmission lines have minimal impact on surrounding infrastructure. Unlike AC transmission lines, DC transmission lines do not produce a time-varying electromagnetic field and, therefore, cannot induce currents or create voltage potentials on adjacent metal structures.

Additionally, corrosion concerns are mitigated by newer buried HVDC cable designs (buried bi-poles with a metallic return) that ensure that there are no appreciable leakage currents (i.e., voltage bleed) that could cause corrosion of adjacent metal pipes.

Importantly, buried HVDC transmission has no detrimental impact on communications equipment. The cables consist of conductive wires surrounded by an insulative polymer coating that prevents the ionization of air adjacent to the transmission line. The ionization of air—known as corona noise or corona discharge—is what produces the potential for radio communications interference (and the audible noise) associated with overhead transmission lines. In addition to the cables themselves, converter stations could also potentially interfere with communications infrastructure. However, they are designed not to via enclosure within a faraday cage.

For additional detailed information on HVDC transmission construction, operation, maintenance and safety, please see the [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#) document.

## Part 1a: MnDOT Key Findings

MnDOT's vision is that "Minnesota's multimodal transportation system maximizes the health of people, the environment and our economy." MnDOT's mission is to "plan, build, operate and maintain a safe, accessible, efficient and reliable multimodal transportation system that connects people to destinations and markets throughout the state, regionally and around the world."

To accomplish its vision and mission, MnDOT must retain its ability to maintain and expand the transportation system as needed to best serve Minnesotans. This includes being able to adapt the system to meet the needs of electric, connected, and autonomous vehicles. MnDOT can accommodate non-transportation infrastructure as long as it does not unreasonably impede highway maintenance and expansion.

### Areas of Analysis

After receiving an introduction to the NextGen Highways vision, the MnDOT Work Group and NextGen Highways Team worked to identify areas where study and/or resolution of specific issues would be required to enable MnDOT to support the location of buried HVDC transmission and fiber in interstate and highway ROW.

#### Relevant Background Areas:

- current policy and regulatory landscape
- MNIT and experience with connecting Minnesota

#### Buried HVDC Transmission & NextGen Highways Areas:

- safety
- alignment with MnDOT's and Minnesota's policies and plans
- overhead infrastructure & location of HVDC converter stations
- potential impacts on existing infrastructure
- environmental impacts
- highway construction
- highway maintenance
- planning and siting utilities in the highway ROW
- transmission permitting
- transmission construction
- transmission maintenance
- future utility relocation responsibilities & costs
- covering MnDOT's costs to support: permit fees and utility leasing fees
- communications infrastructure: fiber, intelligent transportation system, connected and automated vehicles, and broadband

## **A Snapshot of MnDOT Concerns**

### **Safety**

How can maintenance work be done in the vicinity of buried transmission lines?

### **Highway Expansion**

How do we preserve ROW for future expansion?

### **Current Policy Environment**

What are the considerations for changing the longstanding prohibition on longitudinal lines in controlled access highways?

### **Relocation Cost**

How is the cost of relocation of a transmission line paid for?

### **Adjacent Infrastructure**

Are there impacts on existing utilities?

### **Jurisdictional authority**

How would MnDOT's jurisdictional authority of the ROW impact the transmission siting and approval process conducted by Commerce and MN PUC?

## **Key Findings**

After much discussion and additional study for each identified area, the NextGen Highways team and MnDOT determined that some topic areas are relatively simple to address, some are a bit more challenging, and some require additional study. The recurring themes were safety, existing policy and regulation, process, planning, integrated coordination, and resources required to execute the NextGen Highways vision. Each topic presented both opportunities and challenges. While some of the challenges need further analysis, none appear to pose a barrier that cannot be overcome.

A summary of key findings, including opportunities and challenges for each, is presented in the table below, followed by a detailed discussion for each topic.

**Table 3: Findings, opportunities and challenges**

| Topic                              | Key Findings                                                                                                                                                                                                                                                                                                                                                                        |                                                                                                         |
|------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------|
| Current MN Policy                  | Findings                                                                                                                                                                                                                                                                                                                                                                            |                                                                                                         |
|                                    | <p>Longitudinal utility installation is <b><i>not</i></b> allowed in Minnesota interstate and other controlled access highways.</p> <p>MnDOT, MN PUC, and Commerce already coordinate to site proposed transmission lines just outside the ROW. This process can be built upon for siting transmission in ROW.</p> <p>A Dig Once policy has been enacted for broadband conduit.</p> |                                                                                                         |
|                                    | Opportunities                                                                                                                                                                                                                                                                                                                                                                       | Challenges                                                                                              |
|                                    | MnDOT has existing policies, procedures, and relationships for permitting utilities in the ROW that can be used as a starting point.                                                                                                                                                                                                                                                | Both MnDOT policy (its Utility Accommodation Manual) and Minnesota legislation will need to be revised. |
| Regulatory Landscape Outside of MN | Findings                                                                                                                                                                                                                                                                                                                                                                            |                                                                                                         |
|                                    | <p>Some states (WI, NH, ME) allow longitudinal siting of transmission lines in the highway and interstate ROW.</p> <p>The Federal Highway Administration (FHWA) is encouraging state DOTs to allow co-location of fiber, electrical transmission and distribution, and renewable energy in the highway and interstate ROW.<sup>24</sup></p>                                         |                                                                                                         |
|                                    | Opportunities                                                                                                                                                                                                                                                                                                                                                                       | Challenges                                                                                              |
|                                    | A few states have built transmission in the ROW. Their experience, policies, and procedures can serve as examples to build upon. FHWA's support signals a willingness to remove barriers.                                                                                                                                                                                           | Many states still do not allow longitudinal siting of utilities in the transportation ROW.              |

<sup>24</sup> [State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance](#)



| Topic                       | Key Findings                                                                                                                                                                                                                                                                                                                                                           |                                                                                                                                                                                                                                                                                                                          |
|-----------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| MNIT - Connecting Minnesota | Findings                                                                                                                                                                                                                                                                                                                                                               |                                                                                                                                                                                                                                                                                                                          |
|                             | <p>MNIT is the information technology agency for Minnesota's executive branch, responsible for providing IT and enterprise services to agency partners.</p> <p>Connecting Minnesota was a public-private partnership to deploy fiber in the I-94 corridor. The private partner went bankrupt, and the State of Minnesota took over responsibility for the project.</p> |                                                                                                                                                                                                                                                                                                                          |
|                             | Opportunities                                                                                                                                                                                                                                                                                                                                                          | Challenges                                                                                                                                                                                                                                                                                                               |
|                             | <p>MNIT and MnDOT's partnership supports ITS<sup>25</sup> and TSMO<sup>26</sup> needs in the Twin Cities metro region, utilizing highway ROW. This can be expanded to other corridors, such as the I-35 corridor between the Twin Cities and Duluth.</p>                                                                                                               | <p>While the Connecting Minnesota fiber line has been a net positive for Minnesota, there are many within MnDOT who remember the various stresses related to the bankruptcy of the private company, subsequent legal challenges and concerns in the telecom industry that the Connecting Minnesota project produced.</p> |
| Safety                      | Findings                                                                                                                                                                                                                                                                                                                                                               |                                                                                                                                                                                                                                                                                                                          |
|                             | <p>Safety features for HVDC lines include the following (1) burying underground, (2) surface and subsurface markings, (3) restricted access, (4) thick cable insulation, (5) conduit, (6) cable shield ground points, and (7) adherence to MnDOT's utility accommodation manual for permitting, construction, and environmental restoration traffic control.</p>       |                                                                                                                                                                                                                                                                                                                          |
|                             | Opportunities                                                                                                                                                                                                                                                                                                                                                          |                                                                                                                                                                                                                                                                                                                          |
|                             | <p>MnDOT and public utilities both share safety as a top priority.</p>                                                                                                                                                                                                                                                                                                 |                                                                                                                                                                                                                                                                                                                          |

<sup>25</sup> Intelligent transportation systems (ITS) encompass a broad range of wireless and wire line communications-based information and electronics technologies. ITS improves transportation safety and mobility and enhances American productivity through the integration of advanced communications technologies into the transportation infrastructure and in vehicles; [US DOT Intelligent Transportation Systems FAQ](#)

<sup>26</sup> Transportation Systems Management and Operations (TSMO) means an integrated set of strategies to optimize the performance of existing infrastructure through the implementation of multimodal and intermodal, cross-jurisdictional systems, services, and projects designed to preserve capacity and improve security, safety, and reliability of the transportation system; [\(23 USC 101 \(a\) \(32\)\)](#)

| Topic                                                                | Key Findings                                                                                                                                                                                                                                                                                                     |                                                                                                                                |
|----------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------|
| <b>Policy/Plan Alignment</b>                                         | Findings                                                                                                                                                                                                                                                                                                         |                                                                                                                                |
|                                                                      | There is significant alignment between the NextGen Highways vision and MN and MnDOT's existing goals, policies, and strategic plans.                                                                                                                                                                             |                                                                                                                                |
|                                                                      | Opportunities                                                                                                                                                                                                                                                                                                    | Challenges                                                                                                                     |
|                                                                      | Build on shared values, including (1) climate and extreme weather resilience, (2) efficiency in land use and the transportation system, (3) increasing renewable energy generation, and (4) innovation.                                                                                                          | Quantifying the specific benefits that NextGen Highways can be expected to bring to MnDOT.                                     |
| <b>Overhead Infrastructure &amp; HVDC Converter Stations</b>         | Findings                                                                                                                                                                                                                                                                                                         |                                                                                                                                |
|                                                                      | A buried HVDC transmission line would not have any aboveground infrastructure located in the ROW. Associated HVDC converter stations would be placed well outside of the ROW.                                                                                                                                    |                                                                                                                                |
|                                                                      | Opportunities                                                                                                                                                                                                                                                                                                    |                                                                                                                                |
|                                                                      | Burying HVDC transmission lines and siting converter stations outside of the ROW removes collision hazard concerns.                                                                                                                                                                                              |                                                                                                                                |
| <b>Potential HVDC Operational Impacts on Existing Infrastructure</b> | Findings                                                                                                                                                                                                                                                                                                         |                                                                                                                                |
|                                                                      | Buried HVDC transmission lines do not induce currents or create voltage potentials, do not affect nearby communication infrastructure, and do not corrode adjacent metal pipes. HVDC converter stations could interfere with communication infrastructure but are designed not to via the use of a faraday cage. |                                                                                                                                |
|                                                                      | Opportunities                                                                                                                                                                                                                                                                                                    | Challenges                                                                                                                     |
|                                                                      | New HVDC technology eliminates impacts that were of concern for previous technologies and can also be co-located in the same trench as fiber.                                                                                                                                                                    | Different types of utilities may require minimum spacing even if there are no impacts from the buried HVDC transmission lines. |

| Topic                                     | Key Findings                                                                                                                                                                                                                                                                                                                                                |                                                                                                                                                                                                                           |
|-------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Environmental Impacts                     | Findings                                                                                                                                                                                                                                                                                                                                                    |                                                                                                                                                                                                                           |
|                                           | <p>Buried HVDC transmission lines have significantly less impact on the environment than overhead transmission lines.</p> <p>Transmission lines would be subject to environmental requirements in MnDOT's Utility Accommodation Policy and MN PUC's transmission siting process.</p>                                                                        |                                                                                                                                                                                                                           |
|                                           | Opportunities                                                                                                                                                                                                                                                                                                                                               | Challenges                                                                                                                                                                                                                |
|                                           | Burying HVDC transmission lines allows the land aboveground to be restored to a natural habitat.                                                                                                                                                                                                                                                            | Historically, site restoration has not been accomplished after projects. In addition, with ever-increasing extreme weather events, stormwater infrastructure designed for infiltration will compete for space in the ROW. |
| Future Highway Maintenance & Construction | Findings                                                                                                                                                                                                                                                                                                                                                    |                                                                                                                                                                                                                           |
|                                           | <p>MnDOT must be able to maintain and expand the highway ROW as needed to serve the State of Minnesota's transportation needs. Non-transportation infrastructure must not unreasonably impede highway maintenance and expansion.</p>                                                                                                                        |                                                                                                                                                                                                                           |
|                                           | Opportunities                                                                                                                                                                                                                                                                                                                                               | Challenges                                                                                                                                                                                                                |
|                                           | There are successful examples in the US where a state DOT was able to work with the transmission operators to plan and site a transmission line in interstate ROW while accounting for highway maintenance and expansion needs. Looking to WisDOT's experience with the Badger Coulee transmission line in the I-90/I-94 ROW can illuminate best practices. | A deeper understanding and assessment is needed to determine feasibility and best practices for a project that would impact MnDOT ROW.                                                                                    |

| Topic                                                 | Key Findings                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |            |
|-------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------|
| <b>Planning &amp; Siting<br/>Utilities in the ROW</b> | Findings                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |            |
|                                                       | <p>When siting a buried HVDC transmission line or major fiber line, the goal is to place it where it won't have to move (for as long as possible).</p> <p>Increased density of utilities in urban areas and the difficulty of accurately locating existing utilities have led to operational challenges.</p> <p>There is a need for more integrated planning.</p>                                                                                                               |            |
|                                                       | Opportunities                                                                                                                                                                                                                                                                                                                                                                                                                                                                   | Challenges |
| <b>Transmission<br/>Permitting</b>                    | Findings                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |            |
|                                                       | <p>MnDOT has jurisdiction in its ROW and must provide its approval for any transmission project in its ROW in coordination with Commerce and MN PUC.</p> <p>MnDOT does not allow longitudinal transmission installations in interstate ROW today but does allow for utility crossings and transmission siting adjacent to interstate ROW.</p> <p>MnDOT's existing transmission permitting process can be built upon for siting transmission in highway and interstate ROWs.</p> |            |
|                                                       | Opportunities                                                                                                                                                                                                                                                                                                                                                                                                                                                                   | Challenges |

| Topic                                                | Key Findings                                                                                                                                                                                                                                                                                                                                                                                                                 |                                                                                                                                                                                                                                               |
|------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Transmission Construction                            | Findings                                                                                                                                                                                                                                                                                                                                                                                                                     |                                                                                                                                                                                                                                               |
|                                                      | Construction methods, traffic impacts, and safety considerations all must be accounted for and mitigated.                                                                                                                                                                                                                                                                                                                    |                                                                                                                                                                                                                                               |
|                                                      | Opportunities                                                                                                                                                                                                                                                                                                                                                                                                                | Challenges                                                                                                                                                                                                                                    |
|                                                      | The Badger Coulee project in Wisconsin provides an example process to follow. The project included regular meetings between WisDOT and American Transmission Company (the transmission line developer), Constructability Reports, a work zone traffic control plan, permitting for construction, and maintenance.                                                                                                            | The Badger Coulee project is an overhead transmission line in the ROW. An underground project may have meaningful differences that will need to be analyzed and mitigated.                                                                    |
| Transmission Maintenance                             | Findings                                                                                                                                                                                                                                                                                                                                                                                                                     |                                                                                                                                                                                                                                               |
|                                                      | Access to highway ROW presents both safety and security concerns. Modern HVDC transmission lines require minimal maintenance (namely, annual visual inspections). No new security vulnerabilities for MnDOT have been identified.                                                                                                                                                                                            |                                                                                                                                                                                                                                               |
|                                                      | Opportunities                                                                                                                                                                                                                                                                                                                                                                                                                | Challenges                                                                                                                                                                                                                                    |
|                                                      | Siting of cable joint bays where they can be safely accessed, possibly outside of the ROW.                                                                                                                                                                                                                                                                                                                                   | Requires a greater degree of trust and collaboration than currently exists between MnDOT and utilities..                                                                                                                                      |
| Future Utility Relocation Responsibilities and Costs | Findings                                                                                                                                                                                                                                                                                                                                                                                                                     |                                                                                                                                                                                                                                               |
|                                                      | State statute specifies that MnDOT is responsible for all utility relocation costs for utilities located in the interstate ROW. This is contrary to the assignment of relocation costs to the utility for highway ROW in Minnesota and contrary to the policies of many other states. The assignment of utility relocation costs to MnDOT is a barrier to the use of interstate ROW for buried transmission or buried fiber. |                                                                                                                                                                                                                                               |
|                                                      | Opportunities                                                                                                                                                                                                                                                                                                                                                                                                                | Challenges                                                                                                                                                                                                                                    |
|                                                      | WisDOT's model requires utilities to pay for relocation and can be used as a guide. Utilities are accustomed to paying relocation costs throughout most of the US. Planned outage of the line for maintenance can enable consistent coordination between MnDOT and the utility.                                                                                                                                              | Legislative change is needed to transfer cost allocation from MnDOT to the utility. The utility locate process has been difficult due to unresponsiveness from the utilities, inaccuracies for locates, and after-hours work for MnDOT staff. |

| Topic                                | Key Findings                                                                                                                                                                                                                                                                                                                                           |                                                                                                                                                                                                                                                                                   |
|--------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Permit Fees and Utility Leasing Fees | Findings                                                                                                                                                                                                                                                                                                                                               |                                                                                                                                                                                                                                                                                   |
|                                      | MnDOT does not currently charge permit fees or utility license fees for use of its ROW. This poses a financial concern for MnDOT as transmission and fiber build-out in the ROW would increase the amount of required coordination between MnDOT and utilities, consequently requiring more internal MnDOT resources.                                  |                                                                                                                                                                                                                                                                                   |
|                                      | Opportunities                                                                                                                                                                                                                                                                                                                                          | Challenges                                                                                                                                                                                                                                                                        |
|                                      | Many DOTs across the US have permitting and license fee programs that can be evaluated for potential application to a MnDOT program.                                                                                                                                                                                                                   | MnDOT does not charge permit or utility license fees to support staff resources needed for utility coordination and planning.                                                                                                                                                     |
| Communications Infrastructure        | Findings                                                                                                                                                                                                                                                                                                                                               |                                                                                                                                                                                                                                                                                   |
|                                      | <p>There are strong parallels between buried fiber and transmission for siting and construction in an existing ROW.</p> <p>MNIT can barter existing fiber with the private sector. This exchange of fiber resources has reduced public network costs and benefited private sector companies in the network services they provide across the state.</p> |                                                                                                                                                                                                                                                                                   |
|                                      | Opportunities                                                                                                                                                                                                                                                                                                                                          | Challenges                                                                                                                                                                                                                                                                        |
|                                      | <p>There is internal interest in having MnDOT senior leadership decide what MnDOT's role should be in the construction and ownership of additional fiber infrastructure to support greater broadband access and reduce VMT.</p> <p>Fiber supports future connected and autonomous vehicles and intelligent transportation system needs.</p>            | <p>New fiber deployment may generate political opposition from existing broadband providers.</p> <p>Quantifying the amount of new fiber needed to (1) meet broadband needs and (2) meet future connected and autonomous vehicles and intelligent transportation system needs.</p> |

## Recommended Next Steps

**Table 4: Recommended next steps in Minnesota**

| Topic                                                          | Description                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
|----------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>MN Policy &amp; Permitting</b>                              | <p>The NextGen Highways Team and MnDOT review Wisconsin’s laws, policies, and processes that have enabled the location of overhead AC transmission and fiber in interstate and highway ROW.</p> <p>MnDOT, with support from the NextGen Highways Team, examines how to remove barriers that exist in state statute, MnDOT rules, and MnDOT’s utility accommodation policy (e.g., assignment of interstate utility relocation costs to MnDOT). This would include the engagement of other state agencies such as Commerce and MN PUC.</p> <p>The NextGen Highways Team and MnDOT further evaluate potential impacts on vegetation, noxious weeds, wetlands, slope stabilizers, stormwater management, cultural resources, and tribal lands.</p> |
| <b>Transmission: Construction, Maintenance, and Relocation</b> | <p>The NextGen Highways Team and MnDOT further investigate transmission construction, maintenance, and relocation processes, taking lessons from project “Constructability Reports” and maintenance agreements in Wisconsin and incorporating knowledge specific to buried HVDC transmission lines.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| <b>Planning and Siting</b>                                     | <p>The NextGen Highways Team, with support from MnDOT, conducts a GIS review of the suitability of MnDOT’s ROW for buried HVDC transmission and fiber.</p> <p>The NextGen Highways Team, with support from MnDOT, conducts a high-level evaluation of a buried HVDC transmission and fiber project in an interstate or highway corridor that would address known transmission needs (e.g., needs identified by MISO’s long-range transmission planning process).</p> <p>MnDOT, with support from the NextGen Highways Team, examines potential to reduce existing process barriers (e.g., challenges with the current utility locate process).</p>                                                                                             |
| <b>Communications Infrastructure</b>                           | <p>The NextGen Highways Team and MnDOT expand the focus of the work to include fiber and communications infrastructure and support MnDOT as it seeks to clarify (1) its fiber needs to support connected and autonomous vehicles, and (2) fiber needs to support improved broadband access in communities across the state.</p>                                                                                                                                                                                                                                                                                                                                                                                                                |
| <b>Stakeholder Engagement</b>                                  | <p>The NextGen Highways Team and MnDOT engage a greater number of stakeholders outside of MnDOT (e.g., state agencies, utilities, tribes, communities, cities, and companies).</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |

## Part 1b: MnDOT In-Depth Findings

This section of the report provides a detailed discussion for each of the 16 topic areas identified by MnDOT where study and/or resolution is required to enable MnDOT to support the location of buried HVDC transmission and fiber in interstate and highway ROW.

### Current Policy and Regulatory Landscape

#### Current Policy - Longitudinal Utility Installations

Minnesota statutes and rules require utility owners to obtain a permit from MnDOT to install, alter, or maintain utility facilities on trunk highway ROW. MnDOT evaluates the technical aspects of how accommodation of the utility facility will be accomplished. For example, MnDOT would evaluate how and where a utility facility may be located so as not to interfere with other utility facilities or the safety of the traveling public.

Through MnDOT's Utility Accommodation Policy, MnDOT allows the deployment of both transmission and fiber in highway and non-interstate corridors. However, for MnDOT's controlled access corridors – namely the interstate – MnDOT requires utility facilities along interstate highways to be located outside the control-of-access lines, except as outlined in the rules. MnDOT posts a list of Minnesota's controlled access freeway locations online.<sup>27</sup>

#### Longitudinal Utility Installation

Longitudinal utility installations are not allowed in the interstate and other controlled access highways. Longitudinal utility installations are allowed in uncontrolled access highways (e.g., state and US highways).

MnDOT's Utility Accommodation Manual specifies that the utility facility shall not interfere or impair the safety, design, construction, operation, maintenance, stability, or future expansion of the highway. The Utility Accommodation Manual further specifies that new longitudinal installations on highways without full or partial access control shall be located on uniform alignment as near as practicable to the ROW line and outside the clear zone.

In the context of buried HVDC transmission, the interstate corridors are of significant interest since they represent a national network and connect the country's major urban centers, which are also the country's major energy load centers.

An allowance of transmission in interstate ROW would require an expansion of MnDOT's Utility Accommodation Manual in consultation with and approval from the FHWA MN Division office. MnDOT's Utility Accommodation Section III and the Utility Accommodation on Highway ROW Policy

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<sup>27</sup> [MnDOT Trunk Highway Freeway Design and Special Condition Road Sections – No Parallel Installations](#)



apply in certain situations for projects subject to the requirements of 23 CFR § 645.209(g), such as projects within local road and street ROW where federal-aid funds are used. To satisfy the requirements of 23 CFR § 645.209(g), a local agency may exercise its authority to manage utility accommodation pursuant to Minn. Stat. § 237.163, subd. 2(b).

### **Current Policy - Dig Once**

Minnesota enacted a Dig Once policy in 2013 when it created the Office of Broadband Development.<sup>28</sup> According to state law, the Office of Broadband Development “shall, in collaboration with the Department of Transportation and private entities, encourage and coordinate ‘dig once’ efforts for the planning, relocation, installation, or improvement of broadband conduit within the right-of-way in conjunction with any current or planned construction, including, but not limited to, trunk highways and bridges.”<sup>29</sup>

MnDOT and its district offices convene annual utility coordination meetings to inform utilities of MnDOT’s upcoming construction plans.

Further investigation is needed to understand the degree to which the State of Minnesota’s Dig Once policy facilitates the deployment of fiber and, in turn, increases broadband access across the state.

### **Current Policy - Transmission Siting**

Minnesota’s statutory siting guidance for high-voltage transmission lines requires “the evaluation of potential routes that would use or parallel existing railroad and highway rights-of-way.”<sup>30</sup> The statute makes it clear that this preference for co-location stems from a desire to reduce environmental and societal impacts.

As a result of this statute, MnDOT, MN PUC, Commerce have coordinated on the siting of high-voltage overhead transmission lines just outside of the highway ROW. Notably, there are high-voltage transmission lines adjacent to I-90, I-94, and MN-52.

### **Regulatory Landscape**

MnDOT is interested in understanding how Minnesota’s policies compare with federal policy and policies in other states. The NextGen Highways team is in the process of conducting a review of the regulatory landscape. Initial findings reveal that some states (WI, NH, and ME) allow for transmission siting in interstate and highway ROW. The initial findings also show that the FHWA is actively encouraging state DOTs to open interstate and highway ROW to fiber, electrical transmission and distribution, renewable energy generation, and broadband projects.

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<sup>28</sup> [Minnesota Statute 116J.391 Coordination of Broadband Infrastructure Development](#)

<sup>29</sup> Article 14 of the Minnesota constitution established the state’s trunk highway system. Trunk highways in Minnesota that are part of the federal-aid system are also subject to federal statutory and regulatory requirements. For a list of Minnesota’s trunk highways see [List of State Highways in Minnesota](#)

<sup>30</sup> [Minnesota Statute 216E.03 Designating Sites and Routes](#)

## Regulatory Landscape

See [Finding #1 - Transmission and fiber have been and are being sited in interstate and highway ROW across the United States](#) for an introduction to key federal and state policies related to the co-location of transmission in interstate and highway ROW. For a deeper discussion of these federal and state policies, see the [Overview of Federal and State Policy](#) document.

## MNIT and Experience with Connecting Minnesota

### MNIT

Created in 2011, Minnesota IT Services (MNIT) is the information technology agency for Minnesota's executive branch. The agency provides IT services to agency partners and, separately, enterprise services paid for by agency customers. MNIT, in partnership with the Minnesota Department of Employment and Economic Development and Commerce, make up the governor's broadband subcabinet, responsible for collaborating on state government-wide broadband policies.

MNIT also supports local cities and counties. MNIT directly supports towns, counties, and truck stops proximal to MNIT's fiber. Additionally, MNIT has provided fiber lighting services to community organizations in exchange for a nominal one-time fee.

MnDOT, MNIT, and the Minnesota Department of Employment and Economic Development are completing a 10-year investment plan for fiber optic deployment that will support connected and autonomous vehicle needs and broadband needs. As part of this planning, MNIT has met with the private telecommunications industry to understand its broadband expansion goals. As it relates to this network, MNIT and MnDOT have identified a need to build fiber in the I-35 corridor between the Twin Cities and Duluth.

As a final note, MNIT does not receive legislative dollars from the state. The agencies supported by MNIT pay for the cost of its services. Notably, MNIT is audited by the federal government, and any over-collection of funds must be returned to the federal government; otherwise, they face penalties. While not overly problematic, this requirement nonetheless introduces some concerns about any activities that generate revenue.

### Experience with Connecting Minnesota

Twenty years ago, Minnesota allowed for the deployment of a major fiber line spanning the length of the I-94 corridor in the state (from Lakeland to Moorhead). A private company initiated this project, known as "Connecting Minnesota," and received special legislative approval to use the interstate ROW, but then later entered bankruptcy. The state had to take on the fiber build-out and operations, except for an AT&T-owned portion of the line between Plymouth and St. Cloud.

While this fiber project has been a net positive for Minnesota, there are many within MnDOT who remember the various stresses related to the bankruptcy, subsequent legal challenges, and concerns in the telecom industry that the Connecting Minnesota project produced.

## Safety

Safety is the number one priority for MnDOT – just as it is for other state DOTs. The safety of the traveling public, as well as the safety of DOT employees and contractors working on the highway ROW enters into essentially every decision made by MnDOT.<sup>31</sup> Fortunately, safety is also the number one priority for the electric utility industry. In this way, MnDOT and public utilities have a shared priority and vision.

MnDOT raised a number of questions related to safety. Brief answers to these questions are provided here, and more detailed answers can be found in the [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#).

### ***Q. Is there any aboveground infrastructure that would need to be sited within the highway ROW?***

No. The transmission cables and the cable joint bays are buried, and the converter stations would not be sited within the highway ROW.

### ***Q. How is the transmission line protected from accidental contact (e.g., protection from damage by a backhoe)?***

Several safety measures aim to prevent buried transmission lines from being accidentally exposed:

- restricting access to the interstate ROW
- surface markings/warnings
- subsurface marking
- subsurface protection
- conduit
- cable insulation

### ***Q. What would happen if a backhoe or other construction equipment were to contact the line?***

The transmission cable has a strong and thick layer of insulation. As such, simply touching the line while operational would not be problematic. For construction equipment to produce a dangerous line fault, it would have to either (1) pinch the cable against something hard and immovable (e.g., a large rock) or (2) exert enough force on the cable that it snapped into two pieces. Scraping against the cable would initially just displace the cable within the soil. If an operational line were to be severed, a line fault would occur that could be dangerous to personnel working in the immediate vicinity.

### ***Q. What would happen if there were a line fault?***<sup>32</sup>

The line would safely ground itself to the earth via the cable shield ground points. The cable shield ground points are buried in the earth every 1-3 miles.

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<sup>31</sup> The priority MnDOT gives safety cannot be overstated. One member of MnDOT half-joked that if they could just remove the cars from the roads then the highway system could be as safe as they wanted it to be.

<sup>32</sup> A line fault not associated with mechanical severance.

**Q. What safety considerations are associated with the construction of the line?**

Construction-related safety considerations are well-documented in *MnDOT Utility Accommodation and Coordination Manual* Section VII, Construction and Maintenance Requirements and Traffic Control requirements.<sup>33</sup> Construction requirements are outlined in *Minnesota Manual on Uniform Traffic Control Devices*<sup>34</sup> and include the use of appropriate traffic control devices and a traffic control plan.

**Q. Are there any health effects from the standard operation of the line?**

No. The magnetic field directly above the line is roughly twice the strength of the earth's magnetic field and well below the safety thresholds (including those for pacemakers). Ten feet from the line the magnetic field is one-tenth the strength of the earth's magnetic field.

**Alignment with MnDOT's and Minnesota's Policies and Plans**

The State of Minnesota and MnDOT each have goals, policies, and strategic plans that support their missions. To ascertain the overlap between the NextGen Highways vision and these existing documents, the NextGen Highways Team reviewed 15 key documents identified by MnDOT (see table 5).<sup>35</sup>

**A review of these documents indicated significant alignment between the NextGen Highways vision and the State of Minnesota's and MnDOT's existing goals, policies, and strategic plans.**

Notable areas of alignment included accessibility, broadband, carbon reduction and climate resilience, connected and autonomous vehicles, equity, innovation, partnerships, and transportation electrification – including for medium-duty and heavy-duty fleets.

The following table provides a snapshot of the alignment between the NextGen Highways vision and existing missions, goals, policies, and plans of the state and MnDOT.

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<sup>33</sup> [MN DOT Utility Accommodation and Coordination Manual](#)

<sup>34</sup> [Minnesota Manual on Uniform Traffic Control Devices](#)

<sup>35</sup> A full list of documents considered during this study can be found in Appendix A: Existing Plans, Policies, Practices, and Projects that Informed This Work.

**Table 5. Comparison of MnDOT's and Minnesota's policies and plans and NextGen Highways vision<sup>36</sup>**

**Notes:**

- Dark green:** NextGen Highways concepts or close synonyms mentioned by name.
- Light green:** NextGen Highways concepts mentioned (e.g., climate and extreme weather resilience, efficient transportation system and land use, and increasing renewable energy).
- Gray:** Alignment with NextGen Highways vision may exist.
- Light Gray:** No alignment.

|                                                               | Accessibility and/or Broadband | Burying Transmission                              | EV Charging Infra-structure         | Carbon Reduction, Climate Resilience             | Innovation                                    | External Partnerships                                             |
|---------------------------------------------------------------|--------------------------------|---------------------------------------------------|-------------------------------------|--------------------------------------------------|-----------------------------------------------|-------------------------------------------------------------------|
| <b>MnDOTs Vision Minnesota GO</b>                             | Vision, Guiding Principles     | Vision, Guiding Principles                        | Vision, Guiding Principles          | Vision                                           | Vision                                        | Guiding Principles                                                |
| <b>MN SHIP Plan Overview</b>                                  | Investment Categories          | Investment Categories                             | Investment Categories               | Transportation Influences, Investment Categories | Transportation Influences                     | Investment Direction and Project Selection, Investment Categories |
| <b>SMTP Executive Summary</b>                                 | Objective                      | Objective                                         | Objective                           | Objective                                        | Objective                                     | Objective                                                         |
| <b>Sustainable Transportation Advisory Council</b>            | Goals, Recommendations         | Recommendations, Goals*                           | Charter, Recommendations, Goals*    | Goals, Recommendations                           | Recommendations                               | Charter, Goals, Recommendations                                   |
| <b>MnDOT Response: STAC 2020</b>                              | Recommendations                | Recommendations                                   | Recommendations                     | Introduction                                     | Introduction                                  | Introduction, Recommendations                                     |
| <b>MnDOT Pathways to Decarbonizing Transportation</b>         | Executive Summary              | Executive Summary                                 | Website Homepage, Executive Summary | Website Homepage                                 | Executive Summary Background                  | Website Homepage, Executive Summary                               |
| <b>Sustainability &amp; Public Health 2020 Strategic Plan</b> | Vision, Strategic Goals        | Mission, Vision, Guiding Statues, Strategic Goals | Mission, Vision, Strategic Goals    | Mission, Vision, Strategic Goals                 | Mission, Vision, Principles, Strategic Goals* | Mission, Principles, Strategic Goals                              |

<sup>36</sup> MnDOT is updating its Statewide Multimodal Transportation Plan (SMTP). The updated SMTP will reflect an increased focus on climate change and equity, further increasing the already strong alignment that exists between the SMTP and the NextGen Highways vision.

|                                                              | Accessibility and/or Broadband    | Burying Transmission                   | EV Charging Infrastructure            | Carbon Reduction, Climate Resilience | Innovation                 | External Partnerships   |
|--------------------------------------------------------------|-----------------------------------|----------------------------------------|---------------------------------------|--------------------------------------|----------------------------|-------------------------|
| <b>MnDOT CAV Strategic Plan</b>                              | Focus Areas, Key Themes, Goals*   | Focus Areas, Goals                     | Focus Areas, Goals, State-wide Vision | Goals                                | Key Themes                 | Focus Areas, Key Themes |
| <b>MnDOT Fiber Policy</b>                                    | Fiber Optic Infrastructure        | Supports Dig-once Practice             |                                       |                                      | Fiber Optic Infrastructure | Policy Statement        |
| <b>Regional EV Midwest Coalition MOU</b>                     | Background Objectives, Activities | Objectives, Activities                 | Background Objectives                 | Background Objectives, Activities    | Objectives, Activities     | Objectives              |
| <b>Climate Change Executive Order (19-37)</b>                | Comprehensive Equity              | Weather Resilience, 100% Clean Energy* | Clean Energy                          | Goals                                | Subcabinet Duties          | Public Engagement       |
| <b>Our Minnesota Climate Legislative Priorities for 2021</b> | Invest in Rural Communities       | Resilience, Homegrown Energy           | Homegrown Energy                      | Throughout, Resilience               |                            |                         |
| <b>Governor's Task Force on Broadband 2020 Report</b>        | Purpose                           | Recommendation 4                       | Additional Consideration 5            |                                      | Throughout                 | OBD Duties              |
| <b>Dig-Once Policy</b>                                       | Throughout, Subd 2 (d)            | Subd 2(a), (c), (d), Subd 3            |                                       |                                      |                            | Sub 2 (a)               |
| <b>MNIT 2020 Strategic Plan</b>                              | Goals, Guiding Principles*        |                                        |                                       |                                      | Goals                      | Goals                   |

Through the collaboration between the NextGen Highways Team and MnDOT working group, several critical questions emerged regarding the benefits to Minnesota from buried HVDC transmission and how those benefits align with MnDOT's goals. Members of MnDOT asked the following questions.

***Q. How would transmission lines in the highway ROW benefit transportation electrification?***

Transmission lines (AC or DC, buried or overhead) benefit transportation electrification by providing the power for electric vehicle charging in or proximal to the highway ROW. This allows travelers to quickly and easily access charging infrastructure, a critical attribute for driving electric vehicle adoption. Co-location of transmission in the ROW practices system stewardship by helping to get the most out of investments and adapting to changing needs in the transportation system, which is one of the objectives of the 2017 Statewide Multimodal Transportation Plan.

***Q. How would transmission lines in the highway ROW benefit intelligent transportation systems (ITS) and connected and autonomous vehicles (CAV)?***

Buried HVDC transmission does not directly support ITS and CAV. However, buried electrical distribution (AC or DC) in the highway ROW will support these applications by powering the communications and edge computing required for ITS and CAV.

***Q. How would buried HVDC transmission lines in the highway ROW align with the State of Minnesota's and MnDOT's goals?***

Buried HVDC transmission lines in the highway ROW align with many of the goals and values listed in the plans identified in the preceding table. These goals and values include:

- climate and extreme weather resilience
- efficiency in land use and the transportation system
- increasing renewable energy generation
- innovation

Burying transmission lines reduces their exposure to (and potential damage from) extreme weather events while allowing for multiple uses of ROW land. Using the highway ROW allows for expeditious permitting of new transmission, thereby removing a key decarbonization roadblock (the timely build-out of new transmission). HVDC transmission (and their converter stations) offer unique functionality that increases grid reliability and allows for higher penetrations of renewable energy on the grid.

Finally, many of these strategic plans also value new solutions, flexibility, and adapting to change, all of which embody a broad view of serving the state's transportation needs. Burying HVDC transmission lines can be seen as a first step in preparing for the infrastructure needed to serve the state's transportation future, as envisioned by the Minnesota GO guiding principles.

## **Overhead Infrastructure and Location of HVDC Converter Stations**

Two major points of concern for MnDOT were the possibility for overhead infrastructure associated with the buried HVDC transmission lines and the location of the HVDC converter stations.

Overhead infrastructure is a major concern for state DOTs because of the collision hazard immovable objects represent for vehicles departing the interstate at highway speeds. MnDOT wanted to confirm that there was no overhead infrastructure associated with a buried HVDC transmission line (e.g., electrical substations) that would need to be sited within the interstate ROW. Similarly, MnDOT wanted to confirm that the HVDC converter stations would also not be sited within the interstate ROW.

A buried HVDC transmission line would not have any aboveground infrastructure in the interstate ROW. The associated HVDC converter stations are aboveground and would be placed well outside of the interstate ROW. The exact distance from which converter stations will be located outside the interstate ROW will vary based on the specific design requirements and constraints of each individual buried HVDC transmission project.



For additional detail on design and construction requirements for buried HVDC transmission within a highway ROW, please see the [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#) document.

## **Potential Impacts to Existing Infrastructure from Operation of the Buried HVDC Transmission**

Given the infrastructure that has been deployed in or near the highway ROW, MnDOT wanted to understand the potential for buried HVDC transmission to impact existing infrastructure. Such existing infrastructure includes radio communications devices, fiber optic cables, pipelines, and electric transmission and distribution lines.

**In particular, members of MnDOT asked the following questions.**

### ***Q. Does buried HVDC transmission create currents or voltage potentials on adjacent metal structures?***

**No.** DC transmission lines, unlike alternating current (AC) transmission lines, do not produce a time-varying electromagnetic field. As such, HVDC transmission cannot induce currents or create voltage potentials through capacitive effects on adjacent metal structures.

### ***Q. Does buried HVDC transmission affect nearby communication infrastructure?***

**No.** Buried HVDC transmission cables consist of conductive wires surrounded by an insulative polymer coating. The insulator coating serves multiple purposes, including preventing the ionization of air adjacent to the transmission line. The ionization of air—known as corona noise or corona discharge—is what produces the potential for radio communications interference (and the audible noise) associated with overhead transmission lines. (Overhead transmission lines do not have an insulative coating.)

### ***Q. Do HVDC converter stations affect nearby communication infrastructure?***

**No.** HVDC converter stations could interfere with communication infrastructure but are designed not to. Additionally, newer voltage-source converter station designs produce significantly less communication interference (before the use of mitigating measures) than previous load-commutated converter designs.

### ***Q. Does buried HVDC transmission corrode adjacent metal pipes?***

**No.** Newer buried HVDC cable designs (buried bi-poles with a metallic return) will not corrode adjacent metal structures. The bi-pole design with a metallic return ensures that there are no appreciable leakage currents (i.e., voltage bleed) that could cause corrosion of adjacent metal pipes.



## Environmental Impacts

Broadly speaking, one of the advantages of buried HVDC transmission lines is that they have significantly fewer environmental impacts than overhead transmission lines, especially when the lines are buried in an existing ROW. Compared to overhead transmission lines, buried transmission lines:

- require far less ROW (approximately 10 feet in comparison with 200 feet)
- do not impact the viewshed, and
- do not pose an electrocution risk to birds or a collision risk to small aircraft.

**In the context of environmental impacts on the interstate ROW, MnDOT wanted to know the following:**

- Will buried HVDC transmission heat the surrounding soil? If yes, what impacts will this have?
- How will buried HVDC transmission impact existing environmental programs?
- How can MnDOT ensure site restoration work is completed according to contract agreements?
- Will vegetation and wetlands be impacted?
- What are the impacts to slope stabilizers?
- What are the cultural resource impacts and tribal impacts?

### Heating of the Surrounding Soil

Soil temperatures adjacent to the transmission line will increase by roughly one-degree centigrade. It is worth noting that soil temperature is carefully studied during the design process to ensure the safe operation of the buried HVDC transmission cable.

### Existing Environmental Programs

MnDOT has a number of existing environmental programs (e.g., creation of pollinator habitat, the Monarch Highway) that could be impacted by the construction of buried HVDC transmission lines. The NextGen Highways Team fully expects that these impacts are manageable but acknowledges that further investigation would be beneficial.

### Site Restoration

Per contract agreements, MnDOT expects utilities to conduct post-construction landscaping and vegetation management work. From MnDOT's perspective, this site restoration work is often not completed. This creates a challenge for MnDOT as they do not have any enforceable accountability measures. MnDOT also lacks the resources to take on the additional work generated by the installation of utilities within the highway ROW.

### Impacts on Vegetation, Noxious Weeds, Wetlands, Slope Stabilizers, Stormwater Management, Cultural Resources, and Tribes

Potential impacts on vegetation, noxious weeds, wetlands, slope stabilizers, stormwater management, cultural resources, and tribes will be project-specific and go beyond the level of depth covered in this Feasibility Study. They have, however, been identified as topics for investigation in future work.

### Potential Next Steps:

- MnDOT and the NextGen Highways team further evaluate the potential for impact to existing environmental programs.
- The NextGen Highways team conducts further study on vegetation, noxious weeds, wetlands, slope stabilizers, stormwater management, cultural resource, and tribal impacts in Phase 2.
- MnDOT shares with the NextGen Highways team its existing GIS data sets to be incorporated into a GIS review of the suitability of MnDOT's ROW for buried HVDC transmission and fiber.
- MnDOT determines (1) the most common contract shortcomings, (1) whether contract shortcomings are broadly true or isolated to a few utilities, and (3) what options it has to improve contract adherence.

### Highway Construction

MnDOT must be able to alter, update and expand the highway ROW as needed to serve Minnesota's transportation needs. As such, it is critical that the addition of non-vehicle transportation infrastructure to the highway ROW not unduly impede highway construction activities.

Fully assessing the impacts on future highway construction from the addition of buried HVDC transmission to the interstate ROW was beyond the scope of this Feasibility Study and is one of the recommended next steps.

**Yet there are successful examples where a state DOT was able to work with transmission operators to plan and site a transmission line in interstate ROW while accounting for future highway construction needs.**

WisDOT has been able to take highway expansion and maintenance concerns into account when siting overhead AC transmission lines in highway and interstate ROW. As one example, WisDOT worked with American Transmission Company (ATC) and Xcel Energy to site the Badger Coulee transmission line within the I-90/I-94 ROW. See the [Overview of Relevant Projects](#) document for more information on the Badger Coulee transmission line.

For the Badger Coulee project, ATC and Xcel Energy worked with WisDOT early in their development process to identify a rough corridor in which the transmission line could be sited. Then, during the final siting process, WisDOT documented where highway maintenance, upgrades, and expansion would impact the proposed siting of the transmission line. To see examples of the siting guidance that WisDOT provided to ATC and Xcel Energy, please see the [Lessons from Wisconsin's experience utilizing a highway ROW](#) subsection of this Study Report.

### Potential Next Steps

- MnDOT and the NextGen Highways Team review Wisconsin's laws, policies, and processes that have enabled the location of overhead AC transmission and fiber in interstate and highway ROW.
- The NextGen Highways Team enables MnDOT (and other DOTs) to visualize how transmission infrastructure has been sited in highway and interstate ROWs in Wisconsin.

- The NextGen Highways Team, with support from MnDOT, conducts a high-level evaluation of a buried HVDC transmission and fiber project in an interstate or highway corridor that would address a known transmission need (e.g., a need identified by MISO's long-range transmission planning process).
- MnDOT and MN PUC set up a Cooperative Agreement (analogous to the one in Wisconsin), with support from the NextGen Highways Team where needed.

## Highway Maintenance

MnDOT conducts a number of activities to preserve the interstate corridor, meet transportation needs, and ensure safety. These activities can span from keeping roadways clear through mowing and snow or debris removal to maintaining highway conditions by repairing potholes and painting road striping to overseeing sign installations, drainage and ditch clearances, and utility coordination. While such activities are important to be aware of, none were identified that would prohibit the installation of buried HVDC transmission and fiber in highway and interstate ROW.

### Potential Next Steps

- The NextGen Highways Team and MnDOT glean insights into any highway maintenance impacts that have been observed by WisDOT and other state DOTs that allow for the presence of utilities in highway and interstate ROW.

## Planning and Siting Utilities in the Highway ROW

### Planning

**A key realization that emerged while discussing how to incorporate utilities in the ROW was a desire for MnDOT senior leadership to decide what MnDOT's role should be in the construction and ownership of additional fiber infrastructure to support greater broadband access.** This desire stemmed from MnDOT's recent commitment to reducing vehicle miles traveled and from the realization that teleworking has proven itself as a means of transportation.<sup>37</sup> As such, broadband and associated fiber deployment is now a transportation issue.

Discussing this second realization further raised the obvious parallel between the existing transportation system (where MnDOT owns the highway but not the cars using it) and the potential deployment of conduit or conduit plus fiber by MnDOT, where MnDOT would own the mechanism of transportation but not the transported data. Or, more simply, should MnDOT take responsibility for creating another transportation surface? Notably, this "dumb infrastructure" model has already been proposed to promote competition and innovation in vehicle-to-infrastructure technology and infrastructure while minimizing the use of regulator resources and public funding of networks.<sup>38</sup>

**A second realization that emerged was a need for more integrated planning.** Notably, this was a need that already exists today. MnDOT uses a significant amount of fiber in the Twin Cities metropolitan region to support its intelligent transportation system infrastructure. While discussing

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<sup>37</sup> [In Big Move, MnDOT Sets Goal to Reduce Vehicle Miles Traveled](#)

<sup>38</sup> [Smart Cities, Dumb Infrastructure: Policy-Induced Competition in Vehicle-to-Infrastructure Systems](#)

this existing infrastructure and the possibility of adding additional infrastructure, multiple departments within MnDOT agreed on the need to include additional infrastructure considerations at a higher level of planning than has been historically included. For example, stormwater mitigation has been and will continue to be a critical area of focus and concern for MnDOT. Stormwater infrastructure designed for increased infiltration and storage requires more space and flexibility. It could compete with fiber, especially in urban areas.

**A final realization was that utilities in the ROW have proliferated significantly in urban areas and are resulting in operational challenges.**

In the words of another state DOT, “utilities in the ROW have begun to resemble spaghetti.” This increased density of utilities, combined with the challenge of obtaining accurate utility location information (see next section), is leading in part to the 20 or so unintentional backhoe-induced fiber failures that occur each year. Recently, MnDOT experienced an issue with CenturyLink that produced a major stoppage in MnDOT’s work.

**In the context of these planning conversations, two potential solutions were identified:**

- An entity (MnDOT or a private partner) could create multi-utility duct banks that support fiber, transmission, and other utilities (e.g., water, gas). See figure 6.
- Prefabricated concrete ducts that support multiple utility types are a relatively new product (e.g., Forterra’s Red-e-Duct<sup>39</sup> product, see figure 5).
- MnDOT could project future capital projects in the 50-year timeframe utilizing the State Transportation Improvement Plan,<sup>40</sup> Capital Highway Investment Plan,<sup>41</sup> Minnesota State Highway Investment Plan<sup>42</sup> and Minnesota GO<sup>43</sup> plans and identify areas where longitudinal utility installations would be challenging without an entity (DOT or utility) acquiring new ROW.

**Figure 5. Forterra’s Red-e-Duct product**



Photo courtesy of Forterra

**Figure 6. Schematic of designed utility corridors**

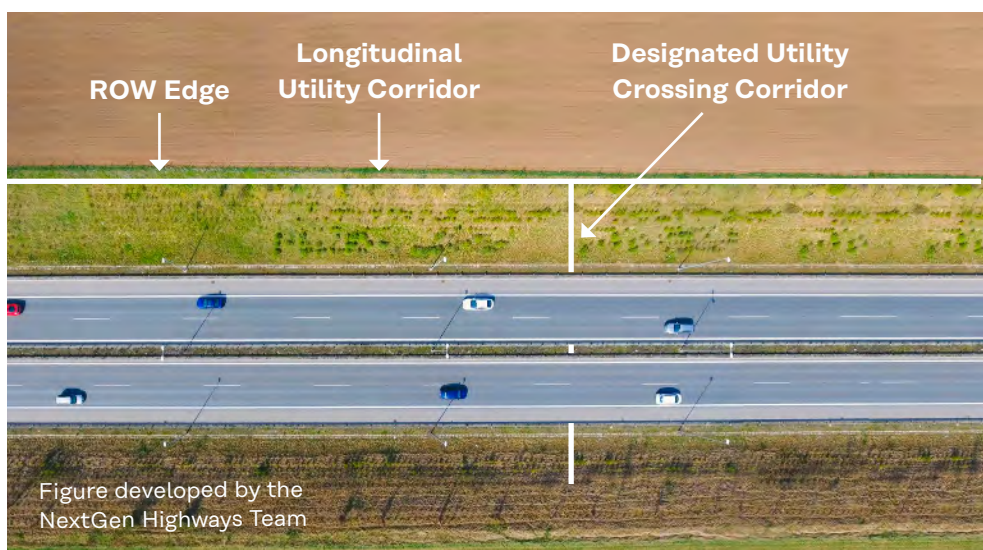


Figure developed by the NextGen Highways Team

<sup>39</sup> [Red-e-Duct](#)

<sup>40</sup> [MnDOT State Transportation Improvement Plan](#)

<sup>41</sup> [MnDOT 10-Year Capital Highway Investment Plan](#)

<sup>42</sup> [Minnesota State Highway Investment Plan \(2018-2037\)](#)

<sup>43</sup> [Crafting a Vision for Generations](#)

## Siting

MnDOT's questions and concerns related to the siting of the transmission line within the highway ROW included the following:

- How closely can adjacent transportation infrastructure (e.g., a sign foundation, bridges, footings, culverts, etc.) be placed near the buried transmission and fiber lines?
- What restrictions on digging will exist once the transmission and fiber lines have been placed (e.g., hand digging within two feet)?
- What are the restrictions on digging around existing utility infrastructure?
- There is incomplete information regarding existing utility infrastructure within the ROW.
  - MnDOT's GIS viewer<sup>44</sup> is a two-dimensional dataset that doesn't contain depth data; as such, there is an ongoing need to determine depth data for utility infrastructure.
  - MnDOT lacks easy access to as-built data for utility infrastructure in the ROW.

### Potential Next Steps:

- The NextGen Highways Team develops an understanding of the siting and digging limitations adjacent to buried transmission and fiber lines.
- The NextGen Highways Team and MnDOT evaluate the potential increase in the electrical and communications infrastructure in and around the highway ROW.
- The NextGen Highways Team and MnDOT evaluate the potential impact of buried transmission lines on gravity flow stormwater systems.
- The NextGen Highways Team and MnDOT evaluate ways to visualize transmission within the highway ROW prior to construction.
- The NextGen Highways Team, with support from MnDOT, conducts a high-level GIS review of the suitability of MnDOT's ROW for buried HVDC transmission and fiber.

## Transmission Permitting

### ROW Jurisdiction

An early question of MnDOT was which state agency (MnDOT or MN PUC) has jurisdiction in MnDOT's ROW. MN PUC and MnDOT quickly determined that MnDOT has jurisdiction in its own ROW (see the [Overview of Federal and State Policy document](#)). The need to answer this question is indicative of the relatively small degree of interaction that exists today between MnDOT and MN PUC.

### MN PUC: Transmission Permitting

In Minnesota, MN PUC and Commerce are responsible for the siting and permitting of proposed transmission projects. As part of this process, MnDOT's opinion is solicited when transmission projects would involve the use of MnDOT ROW. MnDOT participates during routing and siting proceedings, informing the PUC on the compatibility of routes under consideration with MN DOT rules or

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<sup>44</sup> [Georilla](#)



policies. MnDOT's permitting process begins after MN PUC has approved a transmission project's proposed route.

When siting a transmission project, MN PUC and Commerce are aware of MnDOT's restrictions on the use of highway ROW, including MnDOT's prohibition of longitudinal utility deployments within interstate and other controlled access ROW. The PUC and Commerce rely on MnDOT guidance in their evaluation of potential routes.

MnDOT has a single staff member who is deeply engaged with MN PUC's transmission siting process. This staff member has a strong working relationship with their counterparts at MN PUC and Commerce. Knowledge of MN PUC's siting process is highly limited with MnDOT outside of this individual.

### **MnDOT: Transmission Permitting**

As previously noted, MnDOT does not allow for longitudinal utility installations in controlled access highways (namely the interstate). However, MnDOT does allow for utility crossings of controlled access highways and for longitudinal installations and utility crossings in its uncontrolled access highways.

MnDOT's transmission permitting process for utility crossings is an internal process. The process includes many of the same types of reviews within MN PUC's transmission siting process.

An unresolved question for MnDOT was whether its existing permitting process would need adjustments to support a buried HVDC transmission line located in interstate ROW. Similarly, there was an unresolved question of whether the existing opportunities for utilities to conduct pre-permitting discussions with MnDOT would be sufficient for a buried HVDC transmission line. To help address these unresolved questions, members of MnDOT were interested in obtaining information on the practices and policies Wisconsin uses to enable the permitting of longitudinal transmission in interstate ROW.

### **MnDOT Permitting Concerns**

Some specific concerns arose regarding the potential to change MnDOT's longstanding prohibition on the longitudinal installation of utilities in interstate ROW. A brief Q&A for key concerns is provided here:

#### ***Q. What happens if we hit maximum utility capacity? How is utility access to a finite quantity of ROW determined?***

There are different ways this could be addressed, from a first-come-first-served policy to having MN PUC adjudicate access. To start answering this question, the NextGen Highways Team recommends engaging the relevant state and industry stakeholders.

#### ***Q. How many requests might they receive from other utilities (e.g., fiber)? Would they be able to support this increase in requests?***

The NextGen Highways Team recommends that MnDOT engage relevant state and industry stakeholders to identify the potential number of requests and to consult with other states who have already opened their interstate ROW for transmission and fiber installations, such as Wisconsin. Once MnDOT has developed an understanding of the potential increase in requests, it will be better positioned to assess the resources that would be required to support such an increase.

### **Q. Who would own the transmission lines? And would the owner have the ability to take land?**

The transmission lines would be owned by a public utility with the power to take land (if needed). Note, independent transmission developers (e.g., LS Power) would register as a public utility in the State of Minnesota if they were to win a competitively-bid transmission project from MISO.

### **Environmental Permitting**

MnDOT's transmission permitting process includes reviews of impacts on cultural resources, tribal areas, wetlands, and federally-regulated waters, among other natural resources. MnDOT desires to understand better the environmental permits that could be required (e.g., US Army Corps of Engineers 404 permit).

### **Potential Next Steps**

- NextGen Highways Team obtains information from Wisconsin on the practices and policies used to enable transmission permitting in interstate ROW.
- NextGen Highways Team obtains information from Wisconsin on the number of transmission and fiber projects permitted in interstate ROW and an estimate of the resources required to support that permitting.
- NextGen Highways Team and MnDOT engage state, industry, and tribal stakeholders for their input on managing the finite space within interstate ROW and the potential increase in permit requests.
- With support from MnDOT, the NextGen Highways Team investigates and summarizes the likely environmental permits required.

### **Transmission Construction**

The process of constructing buried HVDC transmission lines produced a series of questions from MnDOT regarding construction methods, traffic impacts, and safety considerations. Key areas of concern included the following:

- Non-highway access to the construction area (i.e., use of secondary access)
- Temporary traffic impacts such as the need for shoulder or lane closures that could cause significant interstate impacts
- Potential impacts on the safety of the traveling public

In Wisconsin, transmission developers prepare and submit Constructability Reports to WisDOT for review and approval before any transmission project construction that would use highway ROW.<sup>45</sup> These reports address the above issues and others in detail.

In speaking with WisDOT and ATC regarding the construction process, the following observations were shared:

- **The utility and WisDOT will have met multiple times over a two- to three-year period prior to project application submission**

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<sup>45</sup> For example, see the "[Constructability Report](#)" by American Transmission Company and Xcel Energy, produced for Wisconsin's Badger Coulee project

- “ATC and WisDOT met for months leading up to the permit application to determine what details needed to be included. We continued to meet monthly during construction to review/discuss construction progress and determine if any enhancements to the traffic control plan were needed. All meetings were facilitated by an independent engineering firm that had both WisDOT and ATC as clients.” David Hollenberger, American Transmission Company, Manager, Real Estate<sup>46</sup>

- **WisDOT requires the utility to prepare a Constructability Report during the application process and WisDOT reviews and comments on the Constructability Report**

- The purpose of the Constructability Report is to identify issues such as routing and siting constraints, proposed construction access, and traffic impacts for review by WisDOT.
- The transmission applicants request WisDOT’s concurrence that the preliminary alignments along the highways discussed within the report are permissible. This concurrence is subject to developing a memorandum of understanding outlining major conditions for state trunk highway (STH) occupation, supplemental permit provisions, and other items for discussion and resolution before a draft environmental impact statement submittal (e.g., possible alignment shifts, especially through interchange areas).
- The Constructability Report for the Badger Coulee transmission.<sup>47</sup>

- **WisDOT, in consultation with the utility, sets certain conditions for construction as part of the permit to construction, such as the following examples:**

- Utility construction occurs anytime, sunrise to sunset, Monday thru Friday.
- Weekend work must be prior approved and may be required for traffic stops and slowdowns when traffic counts are low (e.g., Sunday mornings on the interstate).
- Work is typically restricted on major holidays (for example, no lane or shoulder closures starting noon Friday before the Memorial Day or Labor Day weekend and ending 6:00 AM Tuesday morning).
- On the Badger Coulee Transmission Line Project, WisDOT did not allow construction in the Wisconsin Dells area between Memorial Day and Labor Day because of high volume vacation traffic.

- **WisDOT requires the utility to develop comprehensive work zone traffic control plans**

- When lane closures were required on the Badger Coulee project, which were infrequent, they were typically in six-hour increments at night or early morning.
- If traffic stops were required (rarely), they were done in five-minute increments, and ATC paid for State Patrol costs.

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<sup>46</sup> Interview conducted in October 2021

<sup>47</sup> Badger Coulee [Constructability Report](#)



- **WisDOT permits must be acquired for maintenance work**

- Regarding highway access, WisDOT prefers access via private property first or from side roads, then driving along the ROW line.
- Direct highway access is also allowed when other access is not available.
- Access points must be called out on the permit application, and a proper work zone traffic control plan must be provided for each.

#### **Potential Next Steps:**

- The NextGen Highways team and MnDOT review the Constructability Reports from Wisconsin.
- The NextGen Highways team evaluates how the buried HVDC transmission construction processes would meaningfully differ from the overhead construction process in Wisconsin.
- The NextGen Highways team provides MnDOT with an analysis of the likely issues and mitigation methods related to the construction of buried HVDC transmission in MnDOT's ROW.

### **Transmission Maintenance**

Access to the highway ROW is a major concern to MnDOT. Activity in the ROW is a distraction to drivers traveling at high speed, and any vehicles in the ROW represent potential collision hazards for vehicles that depart the travel lanes. Each of these presents a safety concern to MnDOT. Highway ROW access is also a concern for MnDOT for security reasons.

Given MnDOT's safety and security concerns regarding highway access, MnDOT asked the following questions:

#### ***Q. How often will buried HVDC transmission lines require maintenance that requires highway access?***

Modern buried HVDC transmission cables require minimal maintenance over their forty-year design life. These cables use cross-linked polyethylene insulation that, unlike older designs, does not require any cooling oil or oil pumping stations to maintain safe operation. Transmission line operators may elect to perform visual inspections of the cable joint vaults annually. Any other components of the buried HVDC transmission line that would need regular maintenance would be located outside the highway ROW (namely, the converter stations).

#### ***Q. Will additional access points through fencing for access-controlled ROWs be required for transmission maintenance?***

Potentially. The answer will be project dependent. As with any ROW access event, the electric utility will be required to coordinate with the DOT to mitigate any safety and security risks.

#### ***Q. Are there any additional security or terrorist threats that should be considered beyond typical MnDOT infrastructure?***

Additional threats have not been identified, but this topic requires further investigation. This will be best addressed with utility partners in future work.

## Future Utility Relocation Responsibilities & Costs

Utility relocation is the process of moving utility infrastructure in or adjacent to the highway ROW to accommodate the expansion of the highway ROW or the alteration of the highway travel lanes.

As discussed earlier, the goal when siting a buried HVDC transmission line or major fiber line should be to place it where it won't have to move and can be designed around. However, MnDOT's historical experience with the Connecting Minnesota fiber line in the I-94 corridor suggests that the line will have to be moved every few years to accommodate highway maintenance and expansion in and around the Twin Cities metro area. For fiber, this generally results in a 10-12 hour outage for which planning is required.

Depending on a number of factors – including whether the buried HVDC transmission route selected utilized highway ROW in the Twin Cities metro area – it is possible that relocation events for a buried HVDC transmission line could be less than those experienced by Connecting Minnesota. Nonetheless, this is an important issue for MnDOT since they may bear the cost of utility relocation within the highway ROW if those needs come to fruition.

### Operational Costs

MnDOT incurs operating costs (associated with 1-2 full-time employees) when supporting the utility relocation process. Before allowing an increase in the number of utilities sited in the interstate and highway ROW, MnDOT would like to ensure that it has the required operational funding to support the eventual need for utility relocations. When considering the full nature of this concern, it is worth noting that operational funding at MnDOT (and other state DOTs) is much harder to obtain than capital funding. As such, operational funding is quite precious.

### Relocation Cost Allocation

In Minnesota, the entity responsible for the costs of relocation is determined by the location of the infrastructure. For most MnDOT ROW, MnDOT is responsible for all relocation costs for utility infrastructure when relocation is required to go outside of the highway ROW, while the relevant utility(ies) is responsible for relocation costs of infrastructure located within the highway ROW. However, for interstate ROW, MnDOT is also responsible for utility relocation costs for utilities sited within interstate ROW.<sup>48</sup> Given the potentially large costs associated with relocating a buried HVDC transmission line sited within the interstate ROW, MnDOT needs to understand how potential relocation costs would be paid for.

It is worth noting that relocation costs are paid for by the utility in Wisconsin for all WisDOT ROW (i.e., there is no exception for interstate ROW, as there is in Minnesota) in accordance with Wisconsin Administrative Code.<sup>49</sup>

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<sup>48</sup> MN Statute [§161.46 subdivision 2](#), and [§161.45](#); [MN Rule 8810.3300](#)

<sup>49</sup> [Wisconsin Administrative Code, Chapter 220 "Utility Facilities Relocation"](#)

## Planning for Relocation

MnDOT would like to understand whether its existing utility relocation process will work for buried HVDC transmission lines. MnDOT would also like to better understand how utilities would plan for the relocation of a buried HVDC transmission line. With regards to the utility downtime associated with relocation, it is worth noting that HVDC transmission lines are offline for 1-2 weeks per year as the converter stations<sup>50</sup> undergo routine maintenance. This is similar to other energy infrastructure that is offline for multiple weeks per year for maintenance, such as, coal, gas, and nuclear plants. This planned outage period may enable coordination between MnDOT and the utility to align utility relocation work with planned converter station maintenance to minimize impacts on electric customers.

## Utility Location Process

As part of the utility relocation process, MnDOT first has to locate the existing utilities in the ROW. This is referred to as the utility locate process. Discussions of the utility relocation process revealed challenges with the existing utility locate process:

- Significant improvements could be made in utility responsiveness and accuracy for locates.
- The number of utility locates required means that staff is working into the night during construction months.
- Utility locates reportedly cost MnDOT hundreds of thousands of dollars on an annual basis.

Establishing dedicated utility corridors within the ROW is one of the potential solutions identified in this report's [Planning and Siting Utilities in the Highway ROW](#) subsection.

## Potential Next Steps

- Address MnDOT's significant concerns about the cost of relocation of transmission in interstate ROW through (1) conducting additional analysis, either by MnDOT, the NextGen Highways team, or both, on the allocation of relocation costs, and (2) conducting additional ROW valuation analysis in Phase II in partnership with other relevant state agencies.
- MnDOT could enumerate additional transmission relocation protocols for all parties in its Utility Accommodation Policy.
- MnDOT, with support from the NextGen Highways team, addresses relocation process barriers (e.g., ease of obtaining locational information for existing utilities within the interstate ROW).
- Initiate a conversation between MnDOT and Minnesota utilities regarding the relocation process.
- Form a joint committee with MnDOT and utility representatives to develop a set of business practices for relocation and related activities (such as transmission and highway maintenance).

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<sup>50</sup> Note that converter stations will be located outside the highway ROW in all cases and will therefore have no impact on traffic or other activities occurring within the ROW.

## Covering MnDOT's Costs to Support: Permit Fees and Utility Leasing Fees

The build-out of transmission and fiber in the highway and interstate ROW as envisioned by NextGen Highways would increase the amount of coordination and planning required between MnDOT and utilities.

While this increased coordination and planning is not in itself problematic, MnDOT does need to have the resources to support it. This is problematic because MnDOT does not currently have a mechanism to generate the operational funds required to support the increased coordination and planning that would be required. Specifically, MnDOT does not charge permit fees or utility license fees when providing access to the public ROW.

The rationale behind not charging for utility access to the public ROW is that any such charges would be passed on to Minnesotans via their electricity bills. At the same time, operational funding is hard to come by at MnDOT, just as it is at other state DOTs. The lack of permit fees or utility license fees thus leads to a legitimate concern that MnDOT may not have the resources required for the increased utility coordination and planning necessary to support the NextGen Highways vision. A concern that has already been partially validated by operational resource constraints related to maintaining the existing Connecting Minnesota fiber line.

For reference, the NextGen Highways team has loosely estimated that the additional costs are on the order of a few hundred thousand dollars per year, which would translate to low tens of millions of dollars in cost over the 40-year lifetime of a buried HVDC transmission line.

### Potential Next Steps:

- NextGen Highways team and MnDOT evaluate the quantity of additional resources required to support the NextGen Highways vision, drawing on WisDOT's experience.
- NextGen Highways Team conducts a national review of state DOT permit fees and utility license fees.
- MnDOT, with support from the NextGen Highways team, evaluates what would be required to add a permit fee or utility license fee.

## Communications Infrastructure: Fiber, ITS, CAV, and Broadband

The topic of fiber repeatedly arose during the Feasibility Study, despite the study's focus on buried HVDC transmission. This was not entirely unexpected, given the strong parallels between buried fiber and buried transmission and the full scope of the NextGen Highways vision.

The most prominent issue for MNIT and MnDOT is the potential for new fiber deployment to disadvantage existing broadband providers, generating political opposition to new fiber deployment.

MNIT knows that, on the whole, its existing fiber and ability to barter that fiber has been valuable to the telecommunications industry in Minnesota. MNIT has bartered with many different companies, including Charter, Spectrum, Zayo, CNS, and Emerald 2. As a result of this bartering, MNIT believes it has helped increase competition and reduce access costs across Minnesota. However, MNIT also knows

that this increased competition can disrupt existing power balances and that there are those who will be threatened by the expansion of fiber resources in Minnesota.

As MnDOT looks to develop the connectivity infrastructure it requires to support future CAV and ITS needs while also supporting Minnesota's broadband goals, the following questions will need to be addressed:

- How much additional fiber and other communications infrastructure is needed, and for what uses?
- Is MNIT's existing bartering authority sufficient to enable effective and efficient public-private partnerships, or would it help if MnDOT additionally had resource sharing and/or bartering authority with private industry?
- Are there opportunities to align MnDOT's two different fiber accommodation policies? MnDOT utilizes its utility accommodation policy for private fiber and a separate policy for state fiber projects.<sup>51</sup>

### **Potential Next Steps**

- The NextGen Highways Team and MnDOT analyze the fiber and other communications infrastructure required for future transportation needs (e.g., CAV and ITS needs).
- The NextGen Highways Team and MnDOT evaluate the ability for MNIT and MnDOT to site new fiber such that buried HVDC transmission could be sited adjacently in the future.

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<sup>51</sup> Fiber Optic Infrastructure and RTMC Network Access #DM008.

## Part 2: National Findings

The following findings demonstrate that buried HVDC transmission is cost-effective and can be sited in interstate and highway ROW through appropriate consideration of transportation system needs.

### Summary of Findings

1. Transmission and fiber have been and are being sited in interstate and highway ROW across the United States.
2. Much of the interstate is suitable for buried HVDC transmission and fiber, but certain areas require special considerations or routing outside of the interstate ROW.
3. Buried HVDC transmission can be compatible with interstate and highway ROW.
4. Buried HVDC transmission is comparable in cost to overhead AC transmission while providing additional reliability and resilience benefits.
5. Together, DOT ROW and buried HVDC transmission can deliver billions of dollars in societal benefits.
6. Buried HVDC transmission supports transportation decarbonization.
7. Wisconsin has the playbook for siting transmission in DOT ROW.

### Finding #1: Transmission and fiber have been and are being sited in interstate and highway ROW across the United States

Each state sets its own specific utility accommodation rules documented in a utility accommodation plan or utility accommodation manual. These rules are then approved by FHWA. In all states, the DOT retains authority over the use of highway ROW. While many state DOTs allow longitudinal utility installations along uncontrolled access highways, most do not allow longitudinal utility installations along controlled access highways (i.e., interstates). Occasionally, longitudinal utility installations may be allowed along controlled access highways with special approval.

In recent years, a few state DOTs have removed barriers to longitudinal utility installations along controlled access highways for broadband and electric transmission to support greater societal needs. In April 2021, FHWA also removed barriers to longitudinal siting and issued guidance encouraging state DOTs to accommodate broadband and electric transmission projects in the highway ROW for “pressing public needs relating to climate change, equitable communications access, and energy reliability.”<sup>52</sup>

### States are Expanding Broadband Access by Deploying Fiber Using Highway ROW

Several states are now deploying fiber – or taking steps to enable future fiber projects – in highway rights-of-way. Other states are exploring policy changes so they can follow suit. Many states acknowledge future communication needs and the advent of autonomous and connected vehicles in their plans. Many state DOTs receive substantial financial benefits from public-private partnerships, a trend expected to grow with the \$65 billion of federal funding for broadband in the IIJA.

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<sup>52</sup> [State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance](#)

## Some States Have Revised Utility Accommodation Policies to Allow for Transmission Projects

The dominant growth of wind, solar, and geothermal energy resources is increasing demand for transmission to connect these assets to the grid.<sup>53</sup> States are exploring policy changes that will enable siting transmission in highway ROW. Declining costs of buried HVDC transmission cable will likely accelerate this trend.

### Policy and Project Highlights - Fiber

- **North Carolina** is installing 300 miles of fiber optic cable along Interstate 95 and US 70 to expand access to broadband and telecommunication access.<sup>54</sup>
- The **Pennsylvania** Turnpike Commission is deploying 220 miles of fiber to support the commission's communications needs, enable the transition to automated tolling, and support the expected growth of ITS devices and automated vehicles.<sup>55</sup>
- **Utah** DOT partnered with industry to install more than 100 miles of conduit and fiber on UDOT ROW that supports UDOT's communications needs and will enable expanding broadband service to underserved communities.<sup>56</sup>
- The **Arizona** DOT started construction on a fiber optic conduit along a 46-mile stretch of I-17 from Flagstaff to Sedona. The agency is partnering with the Arizona Commerce Authority to increase broadband availability by providing access to ROW along the four main interstates in Arizona.<sup>57</sup>

Several states are developing broadband plans and making the necessary policy changes to facilitate fiber deployment using highway ROWs, including **Wyoming**<sup>58</sup>, **Washington**<sup>59</sup>, **California**<sup>60</sup>, and **Ohio**<sup>61</sup>.

See [Overview of Relevant Projects](#) for greater detail.

### Policy and Project Highlights - Transmission:

- In 2003 **Wisconsin** passed a law establishing existing highway ROW as a priority siting corridor for new transmission lines, second only to existing transmission corridors. Since then, the state has sited several transmission projects using highway ROW.
- In 2010 **Maine** passed a law designating energy corridors for the development of transmission and other energy infrastructure along specific highway and pipeline rights-of-way. Developers can apply to build pipelines, transmission lines, or other energy infrastructure along Interstate-95 and two other state-owned corridors.

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<sup>53</sup> Solar and wind have represented the overwhelming majority of new generation capacity added to the US electric grid in recent years.

<sup>54</sup> [I-95/US 70 Improvements: Innovative Technology and Rural Mobility Improvements](#)

<sup>55</sup> [Fiber Optic Network Will Boost Connectivity, Support Safety, and Mobility Along our Roadway](#)

<sup>56</sup> [How a State Agency Can Drive Fiber Development](#)

<sup>57</sup> [ADOT begins first project to bring broadband internet to rural Arizona communities](#)

<sup>58</sup> [WyoLink and Broadband in Highway Rights-Of-Way](#)

<sup>59</sup> [Broadband Access to State Right-of-Way](#)

<sup>60</sup> [Caltrans Broadband Partnership Opportunity Map](#)

<sup>61</sup> [The Ohio Broadband Strategy](#)

- In 2016 **New Hampshire** passed a law that laid the groundwork for co-locating transmission infrastructure and highways. The law designated portions of I-89, I-93, I-95, and NH Route 101 as energy infrastructure corridors.

**Additional details on these state policies can be found in the [Overview of Federal and State Policy](#) document.**

## **Finding #2: Much of the interstate is suitable for buried HVDC transmission and fiber, but certain areas require special considerations or routing outside of the interstate ROW.**

The development of transmission and fiber lines often requires the ability to acquire or lease significant lengths of ROW – this is especially true for interregional transmission. Utilities often prefer to use a ROW they have developed and own. However, obtaining new ROW is challenging and the optimal route is not always possible.<sup>62</sup> Access to a portion of existing ROW in interstate or highway could offer significant benefits in the development of new transmission and fiber lines. Existing ROW along interstate highways would be especially valuable for the interregional transmission lines needed to cost-effectively decarbonize the grid while improving its reliability and resilience.

If interstate and highway ROW were made available for transmission development, a typical transmission project would likely use a portion of the highway ROW while also using existing utility and rail ROWs. The transmission line would not be fully sited within the highway ROW alone. In these circumstances, siting of the transmission line within the ROW would be done in close collaboration with the existing ROW owner (e.g., the DOT) and would take into account current and future transportation needs.

While not all highway ROW is suitable or available for electric transmission (siting within urban corridors can be particularly challenging), ROW in rural areas can be suitable (see figure 7). In rural areas, the ROW is often 300 feet wide, and other utilities and land uses are not as competitive.

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<sup>62</sup> A number of overhead interregional transmission projects have been successfully blocked by public opposition in recent years.



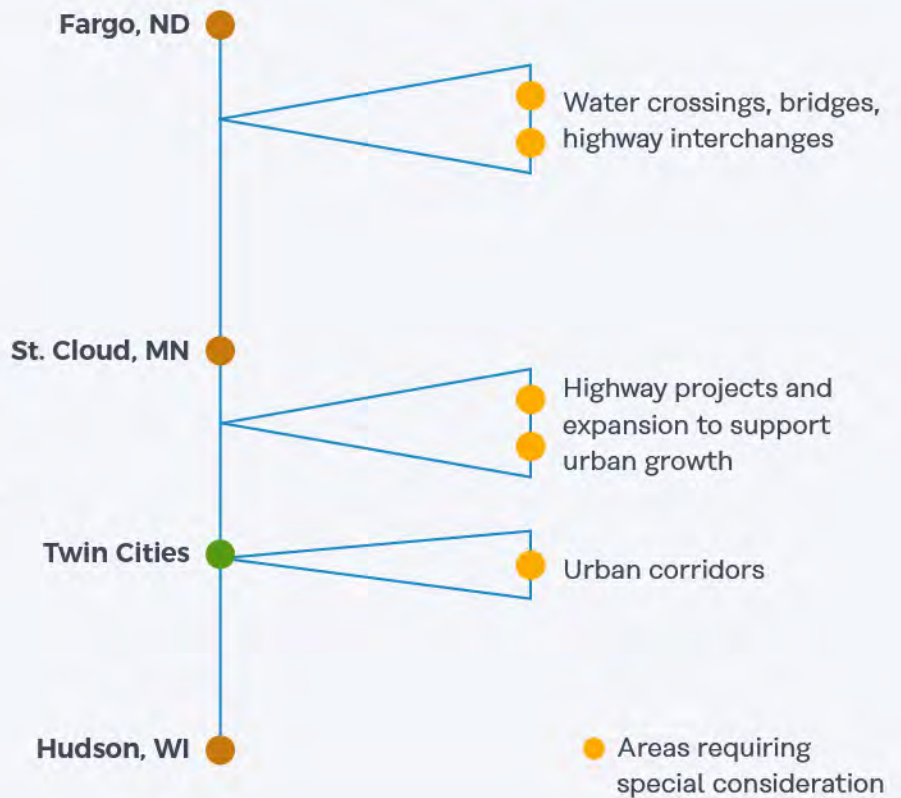
**Figure 7. Utilizing a highway corridor**

**1. A large portion of the interstate is suitable for the development of linear infrastructure**



**Best placement next to ROW edge**

**2. But certain areas require special consideration and/or routing outside the highway corridor**



Key elements that require special consideration when determining the suitability of transmission siting in the interstate and highway ROW include impacts from or impacts on the following:

- Urban corridors
- Construction of new interchanges and bridges (primarily driven by safety upgrades and population growth through suburban expansion)
- Crossing bodies of water, bridges, and interchanges
- Stormwater systems and resilience/mitigation for increased stormwater due to climate change.

### Urban Corridors

Urban corridors are particularly challenging locations to site utility infrastructure given the high percentage of the ROW dedicated to the travel lanes. Examples include the I-35W corridor just south of Minneapolis and the I-94 corridor between Minneapolis and St. Paul. Additionally, noise walls in urban areas present unique challenges given their proximity to the edge of the ROW and construction requirements.

## Construction of New Interchanges and Bridges

Constructing new interchanges and bridges will likely create the largest operational challenges to siting transmission in the highway ROW. As urban areas grow, MnDOT needs to expand the highway infrastructure to accommodate the increased population. When MnDOT constructs new interchanges, bridges, travel lanes, etc., adjacent utilities may need relocation.

## Crossing Bodies of Water, Bridges, and Interchanges

Siting linear utilities that cross bodies of water, bridges, and interchanges require additional planning to avoid or mitigate impacts on existing infrastructure and the environment. Bridges and interchanges require frequent routine and emergency maintenance and repair. Bodies of water have strict environmental protection requirements. Constructing and maintaining a transmission line near these areas must minimize its impact on the existing infrastructure and environment. It must also account for the inevitable future impact that maintaining, repairing, or expanding these areas can pose to the transmission line.

## Stormwater Systems:

As Minnesota continues to experience more intense rain events at greater frequency, culverts and other elements of stormwater management systems will need to be redesigned. Nature based stormwater infiltration systems effectively manage increased quantity while providing better water quality treatment. However, these systems typically take up more space, which could impact siting of a transmission line.

The resounding consensus from a number of the MnDOT departments interviewed was that these transmission lines should be installed in a way that would minimize the potential for future movement. This would reduce relocation costs and planning efforts. Therefore, if these lines were allowed to be accommodated in the interstate or highway ROW, they should be located in areas where they would ideally never have to be moved. Preferably, they would also be located in areas with secondary access that can be used for maintenance needs.

## Lessons from Wisconsin's Experience Utilizing Interstate ROW

The Badger Coulee project in Wisconsin provides a good example of how to account for future highway and maintenance needs during the transmission siting process. The project also shows how to avoid future relocation events. As discussed in the Badger Coulee Transmission Line Final Environmental Impact Statement, a significant portion of the transmission line is located longitudinally within WisDOT's ROW for I-90/I-94.<sup>63</sup> During the siting process for the Badger Coulee transmission line, WisDOT provided comments to the Public Service Commission of Wisconsin that:

- ensured WisDOT's future needs were met, and
- suggested changes to the siting of the transmission line to avoid the need for future line relocations to accommodate already planned upgrades within the I-90/I-94 corridor.

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<sup>63</sup> [Badger Coulee Transmission Line, Volume 1: Environmental Impact Statement](#)

The following are three examples of how WisDOT worked with ATC to (1) identify areas where future highway maintenance and construction would be required and (2) site the transmission line in a location where the need for a future relocation event could be avoided where possible:

“WisDOT opposes short jogs in transmission line ROW since it hampers its ability for future highway expansion. A more gradual shift is preferred to allow for smoother/easier transitions should horizontal curves need to be constructed to avoid relocation of transmission line structures. WisDOT is not opposed to its ROW being used for the transmission line ROW in this corridor. In addition, the same issues faced by the applicants regarding the inability to get approvals from USFWS to locate through its territory will likely be faced by WisDOT. Therefore, any expansion will need to be on the north side of the highway.”

“Since the existing bridges are next to each other, any expansion would likely include constructing a new structure on one side or the other. Should the east side be selected, the applicants’ transmission line would have to be relocated if it was not located sufficiently away from the proposed new bridge site. ... See attachment #3.”

“WisDOT is currently studying the corridor from the USH 12/STH 16 interchange to the I-39/STH 78 interchange on I-90/94 for major improvements and expansion. This includes improvements to all four interchanges in Wisconsin Dells and the major system interchange with I-39 south of Portage. No matter which transmission line alternative is selected, it is highly likely that the applicants’ structures will have to be relocated to accommodate highway improvement and expansion. The WisDOT Southwest Region – Madison office has put together a summary of the proposed actions and parameters. See attachment #2.”

For more information, see Appendix E of Vol 1 of the Final Environmental Impact Statement for the Badger Coulee Transmission Project.

### **Finding #3: Buried HVDC transmission can be compatible with interstate and highway ROW**

The NextGen Highways Team’s investigation, coupled with learnings from projects under development in Europe, demonstrates that buried HVDC transmission can be sited feasibly in interstate and highway ROW. Doing so requires close collaboration between the DOT and utility to ensure the project design accounts for existing and future transportation needs. As discussed in Finding #2, certain areas will not be practical to site buried HVDC transmission in the interstate or highway ROW. But the existence of specific constraints doesn’t prevent the broader use of the interstate and highway ROW.

The NextGen Highways Team investigated the following topic areas and produced the [Introduction to Buried High-Voltage Direct Current \(HVDC\) Transmission for DOTs](#) document that discusses each area to help MnDOT (and other state DOTs) evaluate the compatibility of buried HVDC transmission within highway and interstate ROW:

- system design
- safety
- transmission construction techniques

- transmission maintenance requirements
- potential for impact on existing infrastructure and devices
- environmental impacts

Notably, buried HVDC cables would require a small fraction of the width of the interstate ROW (<5 percent in rural areas). Interstate highway ROW in rural areas is typically 300 feet wide, and buried HVDC transmission cables require a corridor that is 5 feet wide and 5 feet deep.

While the ROW required for buried HVDC cables is relatively modest, additional space may be required to meet offset requirements for other utilities in the interstate ROW and during construction for equipment. These additional space requirements will vary by project and need to be considered on a project-by-project basis.

Unresolved questions remain regarding the transmission construction process and what those impacts may be on the transportation system. There is also a need for careful consideration to minimize or altogether avoid impacting highway construction expansion as forecasted over a state DOT's long-range planning horizon. Future work will investigate these questions.

As a final note, many of the identified issues regarding buried HVDC impacts on the ROW are highly analogous to the impacts from fiber infrastructure. This is encouraging given the history of successfully siting fiber infrastructure in the interstate and highway ROW across the United States. As such, if fiber is possible, then buried HVDC transmission should also be possible, especially since co-location of the two is possible.

## **Finding #4: Buried HVDC transmission is comparable in cost to overhead AC transmission while providing additional reliability and resilience benefits**

### **Transmission Cost Comparison**

Buried HVDC transmission costs have declined and become competitive with traditional overhead AC transmission. The technology for buried HVDC transmission has matured, and the industry has gained experience designing and building projects across the world. Figure 8 compares transmission cost on a capacity-normalized basis (dollars per gigawatt-mile of transmission capacity) for a few representative transmission projects in the United States. The figure shows that buried HVDC projects are cost-competitive with overhead AC transmission projects.<sup>64</sup>

<sup>64</sup> The cost comparison presented includes all of the MISO Multi-Value Projects [[Multi Value Project Portfolio Results and Analysis](#)] that are over 100 miles long: 1-Brookings SD - SE Twin Cities; 2- Lakefield - Winnebago - Winco - Burt Area & Sheldon - Burt Area - Webster; 3- Winco - Lime Creek - Emery - Black Hawk - Hazleton; 4 - N. Lacrosse - N. Madison - Cardinal (i.e., Badger Coulee); 5 - Cardinal - Hickory Creek; 6- Big Stone South - Ellendale; 7- Maywood - Herleman - Meredosia - Ipava & Meredosia - Austin; 8 - Pana - Faraday - Kansas - Sugar Creek; and 9 - Reynolds - Burr Oak - Hiple. The buried HVDC projects included in the cost comparison were: 1 – SOO Green HVDC Link; 2 – Clean Path New York; and 3 – Champlain Hudson Power Expressway.

**Figure 8. Transmission cost comparison: overhead AC and buried HVDC**

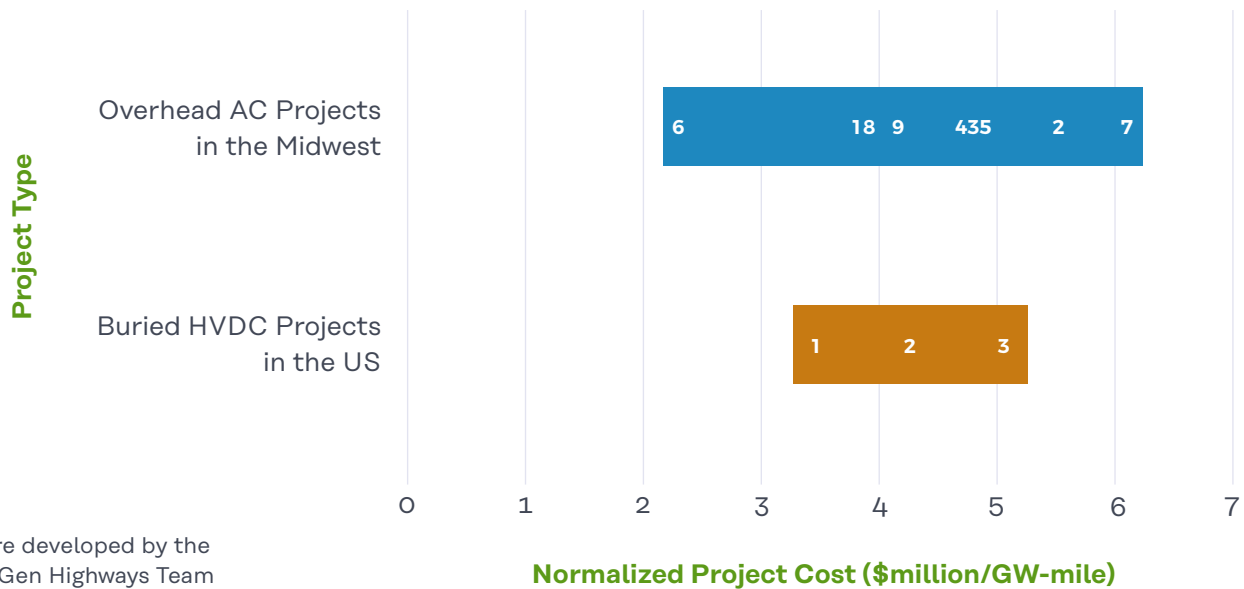


Figure developed by the  
NextGen Highways Team

Historically, utilities have discounted the use of underground transmission because buried AC line costs were often 7 to 10 times more costly than overhead lines. Today, some utilities will still cite those cost comparison numbers without considering the technological advances of HVDC cables and converter stations over the past decade.

The NextGen Highways Team researched the cost of buried HVDC transmission to facilitate a greater collective understanding of the recent cost declines and the difference in cost between overhead and underground transmission.

Notable takeaways from the NextGen Highways Team's research:

- Buried HVDC transmission is cost-competitive with traditional overhead AC transmission projects.
- Buried HVDC transmission is roughly 2-4 times the cost of overhead HVDC transmission.<sup>65</sup>
- Buried HVDC transmission costs fell over the last decade:
  - converter costs have fallen from \$300 million per gigawatt (GW) per converter down to a conservatively estimated \$200 million per GW per converter, and
  - installed cable costs have fallen from over \$3 million per GW-mile to \$1-2 million per GW-mile.

### Benefits from Buried HVDC Transmission

When evaluating transmission projects, the utility regulatory process considers costs and benefits. Increasingly, there is a growing recognition of the need to include a greater number of benefits in the regulatory process.<sup>66</sup> This is especially true with regard to grid reliability,<sup>67</sup> grid resilience, and climate

<sup>65</sup> This assumes that the overhead HVDC transmission can be permitted and built. Over the last decade, a number of overhead HVDC transmission projects across the US were unable to be successfully built, including Northern Pass, New England Energy Connect (still active), Plains and Eastern, Grain Belt Express (still active).

<sup>66</sup> [Brattle Transmission Planning and Cost-Benefit Analyses Presentation](#)

<sup>67</sup> [Report on Opportunities and Barriers to High-Voltage Transmission; Transmission Makes the Power System Resilient to Extreme Weather; Interconnections Seam Study](#)

resilience benefits.<sup>68</sup> In the context of buried HVDC transmission, there are important benefits that should be considered:

- Grid reliability
- Grid and climate resilience
- Accelerated permitting timeline (as discussed in Finding #5)

### **Grid Reliability**

In 2021, MISO issued its Renewable Integration Impact Assessment report.<sup>69</sup> The report identified grid reliability needs as renewable energy levels grow in the region. These needs included increased frequency and voltage support, particularly in areas of concentrated renewable generation development, and an expanded ability to move energy across the region daily to balance renewable generation and load.

HVDC technology can simultaneously address many of MISO's identified needs by providing voltage support, frequency regulation, and weak-grid support benefits. By doing so, HVDC transmission can improve the grid's overall operational efficiency and stability.

### **Grid and Climate Resilience**

The simple fact that buried HVDC is underground results in electric grid resilience<sup>70</sup> that overhead transmission cannot achieve. Buried transmission can survive major weather-related disturbances such as hurricanes, tornadoes, and ice storms and doesn't require shutting off the grid during high fire risk periods. HVDC transmission also provides electricity grid resiliency because of services it can provide, such as "black start" capabilities that are critical to re-starting the electric grid after a blackout.

The following examples are recent significant weather and electric infrastructure events that demonstrate the risk associated with the overhead high-voltage electric system. Buried electric transmission in Louisiana during the two hurricanes would have avoided some of the negative impacts and economic hardship resulting from the storms.

#### **Hurricane Laura (August 2020)**

Hurricane Laura severely damaged the power grid in Louisiana and Texas. Nine of the nine transmission lines that deliver power into the Lake Charles area were out of service, with multiple transmission structures damaged beyond repair.

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<sup>68</sup> [Accelerating Decarbonization of the U.S. Energy System; Transmission Planning for 100 Percent Clean Energy](#)

<sup>69</sup> [Renewable Integration Impact Assessment](#)

<sup>70</sup> "Although the two terms [Grid Reliability and Grid Resilience] often are used interchangeably, they are not the same. Grid reliability is commonly defined as the ability of the electric power system to deliver electricity in the quantity and with the quality demanded by end-users. Resiliency is the ability for the electric power system to withstand and recover from extreme, damaging conditions, including weather and other natural disasters, as well as cyber and physical attacks. While the two are different, resilience directly impacts reliability." See [Informing the Transmission Discussion](#) for further discussion.



### **Hurricane Ida (August 2021)**

Hurricane Ida devastated both Louisiana and Mississippi's power grids, knocking out electricity to more than 1 million customers, including all of New Orleans. All eight transmission lines that deliver power into New Orleans were out of service and multiple transmission structures were damaged beyond repair.

### **Kincade Fire (October-November 2019)**

CalFire determined the Kincade Fire was caused when a jumper cable on a PG&E transmission tower broke in high winds, fell, and arced against the tower. The arc caused molten material to fall into vegetation and ignite below the tower. It took CalFire 15 days to contain the fire. The blaze burned more than 120 square miles and destroyed 374 buildings.

**Figure 9. Damage from Hurricane Laura on overhead transmission**



### **Grid Reliability and Resilience Are Only Growing in Importance**

As the nation continues to electrify and digitize the economy, the electric grid's reliability and resiliency are becoming more important every year. In 2021, Winter Storm Uri's impact to Texas electric grid and natural gas infrastructure foreshadowed what the severity of a major grid outage could look like in a fully electrified future. In Texas, the partial loss of the electric grid and natural gas infrastructure led to the loss of 210 lives and estimated financial losses between \$80 billion to \$130 billion.

### **Finding #5: Together, DOT ROW and buried HVDC transmission can deliver billions of dollars in societal benefits**

By building a buried HVDC transmission system alongside our interstate network of roads and rail lines, the country can overhaul and expand the transmission network more quickly, cost-efficiently, and easily than developing a new ROW through private land. Benefits of this approach accrue to landowners, electric customers, and the grid itself.

**Societal value from using the interstate and highway ROW:** the NextGen Highways team estimates that using buried HVDC transmission in interstate and highway ROW can generate \$150 billion of societal value by shaving five years (or more) off the permitting and siting timeline for interregional transmission projects.

Siting, permitting, and building a traditional overhead HVAC transmission line typically takes at least 10 years and often much longer because of challenges related to cost, environmental permitting, and siting on private land. Using highway and rail ROW means working with fewer property owners – potentially just a handful instead of many hundreds. It also largely removes the threat of eminent domain to take land from private owners.

**As shown in table 6, shaving five years off of the permitting timeline for a single interregional transmission project can generate a billion dollars of societal value.** Assuming a 2 gigawatt (GW) buried HVDC transmission line delivering 1 GW of renewable energy resources,<sup>71</sup> then 8,760 GW-hours of clean energy would be transmitted annually. Further assuming 0.5 tons of avoided carbon emissions per megawatt-hour (MWh) of energy,<sup>72</sup> then more than four million tons of carbon emissions would be avoided each year. Using a conservative value of \$50 per ton for the avoided carbon emissions, the societal value of thee avoided emissions would more than \$200 million annually. Thus, the five-year reduction in the transmission development timeline that the NextGen Highways Team believes is possible (for a typical interregional transmission project) would translate into \$1 billion of societal value.

**Table 6. Societal Benefits from a Single 2 GW Buried HVDC Transmission Line.**

| Metric of Interest                              | Value                   | Assumption                         |
|-------------------------------------------------|-------------------------|------------------------------------|
| Renewable Energy Transmitted                    | 8,760 GW hours per year | 2 GW line with 50% utilization     |
| Avoided Carbon Emissions                        | 4,380,000 tons per year | Baseline: 0.5 tons emitted per MWh |
| Value of Avoided Emissions                      | \$219 million per year  | \$50 per ton of carbon             |
| Reduction in Permitting Timeline                | 5 years                 | 10+ years → 5 years                |
| <b>Societal Value of DOT ROW (for one line)</b> | <b>\$1,095,000,000</b>  | 5 years * \$219 million/yr         |

<sup>71</sup> We conservatively assume that the line will not be loaded in excess of 50 percent of its capacity on average.

<sup>72</sup> This is the current emissions rate in the Midwest and many other parts of the country.



It is worth noting that a 2GW, 300 miles-long, buried HVDC transmission line would cost roughly \$2.5 billion. As such, \$1 billion of societal value would equate to 40 percent of the transmission line's cost.

Scaling the societal benefits from a single interregional transmission line to meet estimated interregional transmission needs yields about \$150 billion of societal benefits from coupling buried HVDC transmission with our existing transportation ROW.<sup>73</sup>

Finally, building HVDC transmission alongside highways can support a broad array of electrification projects. These projects range from electrifying fleets in dense warehouse districts to installing over-the-road electric vehicle (EV) charging to the electrification of space and water heating in dense urban areas. This is described further in the next section.

## **Finding #6: Buried HVDC transmission supports transportation decarbonization**

Buried HVDC transmission supports transportation decarbonization in three key ways:

1. Transportation decarbonization requires grid decarbonization, and grid decarbonization requires buried HVDC transmission.
2. With strategic guidance, the build-out of buried HVDC transmission will create economic development zones adjacent to HVDC converter stations. These economic development zones will be logical locations to site fleet and over-the-road EV charging infrastructure and data centers.
3. The advancement of solid-state converters and other advanced grid technology will enable EV charging to occur directly from medium and/or high-voltage DC systems.

### **How can HVDC transmission support transportation decarbonization?**

Before discussing these three ways in detail, it is worth stating why many assume HVDC transmission is not relevant to transportation electrification: the cost of the HVDC converter stations.

HVDC converter stations are required to convert high-voltage DC power to high-voltage AC power. High-voltage AC power is then stepped down using a traditional AC transformer from the high voltage of a transmission line (e.g., 525 kV) to the lower voltage needed for electric vehicle charging (e.g., 1.5 kV for medium- and heavy-duty fleets). HVDC converter stations cost between \$200 and \$400 million, depending on their voltage and capacity.

Connecting to an HVDC transmission line is cost-prohibitive unless one is serving roughly 1,000 megawatts of electrical load. By comparison, the electric load from the electrification of fleets in a large warehouse district is hundreds of MW, and the load from EV charging along interstates will be tens of MW. This load discrepancy leads many to assume too quickly that HVDC transmission is not important to transportation decarbonization.

As illuminated by the following subsections, this is an oversimplified assumption that fails to account for the importance of (1) grid decarbonization, (2) economic development opportunities created by converter stations, and (3) technology advancement.

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<sup>73</sup> [Transmission Planning for 100% Clean Electricity](#)

## Transportation decarbonization requires grid decarbonization, and grid decarbonization requires buried HVDC transmission

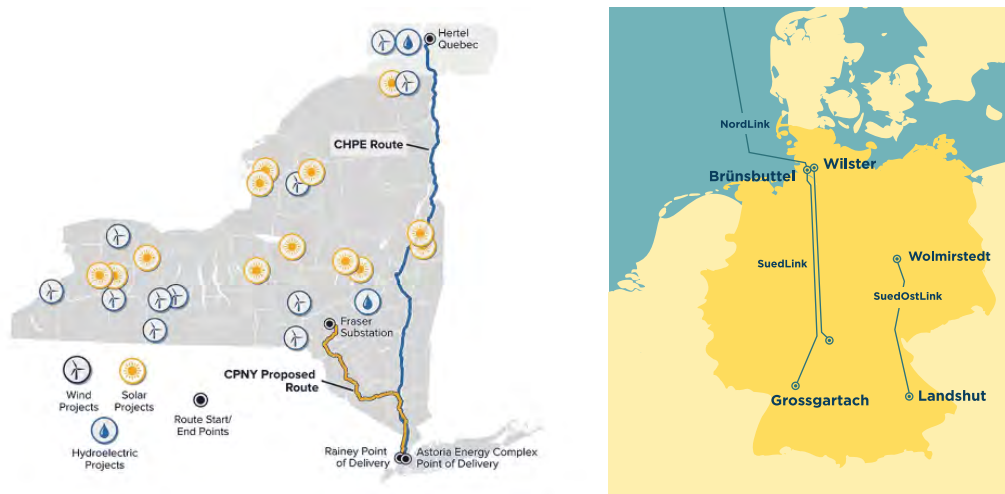
Transportation electrification must be coupled with grid decarbonization to achieve transportation decarbonization.

Unlike the US Interstate Highway System, the US power grid is composed of many discrete regions. Modeling study after modeling study has shown that connecting these regions is critical to cost-effective grid decarbonization.<sup>74</sup> It is also critical for grid reliability and resiliency (see the [Review of Interregional Transmission Studies](#) document).

Despite the importance of connecting the electric grid regions using interregional transmission lines,<sup>75</sup> project after project has failed in the US. Since 2014, the US has not built a single GW of interregional transmission capacity. Meanwhile, China, Europe, South America, and India have collectively built nearly 350 GW of interregional transmission capacity. Most recently, the construction of the New England Clean Energy Connect transmission line was stopped indefinitely by a public referendum in November 2021. This was an incredible result given that the New England Clean Energy Connect had already received the required regulatory approvals and was in the process of being built.

As seen in Europe and now in New York State, buried HVDC transmission is being used to build the interregional transmission required to cost-effectively and reliably decarbonize the electric grid. The transmission routes for four buried HVDC transmission projects currently under development/construction in New York<sup>76</sup> and Europe<sup>77</sup> are shown in figure 10.

**Figure 10. Maps of Buried HVDC Transmission Projects in New York and Germany**



Left figure courtesy of NYSERDA | Right figure developed by the NextGen Highways Team

<sup>74</sup> [The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System; Interconnections Seam Study: Transmission Planning for 100% Clean Electricity](#)

<sup>75</sup> Interregional transmission lines move power hundreds and even thousands of miles to connect different regions of the grid.

<sup>76</sup> [New York State Department of Public Service Approves Buried HVDC Transmission Projects](#)

<sup>77</sup> [NKT Website](#)

In the words of Cornelis Plet - a Principal Consultant with DNV and leading expert on HVDC transmission:

***“[Subsurface] HVDC technology enables economic transmission with low environmental and visual impact... enabling delivery of offshore wind power further inland, closer to load centers, and also enabling connections between different states and remote renewable energy resources.”<sup>78</sup>***

**With strategic guidance, buried HVDC transmission systems will create economic development zones that include EV charging infrastructure**

HVDC converter stations are a natural location for creating economic development zones. This is because customers adjacent to these converter stations will have direct access to the grid's cleanest and most reliable power. This will be especially true to the degree that the converter stations are connected to buried HVDC transmission lines. Data centers, logistics centers, and military assets (new or existing) are some of the obvious entities that should want to be close to an HVDC converter station. Governors, mayors, and state and regional agencies have the opportunity to guide the siting of HVDC converter stations to maximize their economic and societal value. Specifically, elected officials and government staff can work to create economic development zones that serve multiple needs:

- on-boarding of clean generation
- serving new loads (data centers, over-the-road EV charging, and depot-based fleet charging)
- serving critical existing loads (downtown cores and military bases)
- improving grid economics and reliability

Such economic development zones will likely have the greatest value in rural areas. In rural areas, the development of multiple GW of clean energy can cover the cost of the converter stations. This will entice economic development in the form of data centers, logistics parks, over-the-road EV charging, and/or renewed investment in existing military assets. By guiding the siting of converter stations towards key transportation corridors – ideally spaced every 100-150 miles – elected officials and state agencies can ensure the public derives the greatest value possible from the build-out of HVDC transmission lines and their associated converter stations.

Furthermore, by linking the development of data centers, logistics parks, and/or the hardening of military assets to the development of renewable resources, economic development zones would tie land use to economic growth and might just start helping to repair our rural/urban divide.

The strategic creation of economic development zones will also deliver societal value in urban areas. A combination of loads, including depot-based fleet charging in dense warehouse districts, and a large value for grid reliability and resilience (from the large population and commercial activity) can cover the cost of the converter stations in urban areas.

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<sup>78</sup> [Offshore Wind: The key to unlocking the American transition to a clean, reliable and affordable energy future](#)

## **The advancement of solid-state converters and other advanced grid technology will enable EV charging to occur directly from medium and/or high-voltage DC systems**

Directly charging EVs from an HVDC transmission line will require significant advancement of solid-state power conversion technologies. Fortunately, the broadly recognized need for grid functionality, grid security, and grid reliability are resulting in the development of the required solid-state power conversion technologies.

In “Reimagining the Grid,” Southern California Edison (SCE) did a laudable job of distilling future grid challenges, including those that will be faced in transportation corridors:

***“Sites with commercial EV fleets relying on fast charging will stress the existing distribution system’s capacity within these corridors, and aggregate load from all EV charging in the region will push the capacity of the subtransmission system that links these corridors to the high-voltage transmission network.”*<sup>79</sup>**

SCE’s analysis considered future grid options for transportation corridors and specifically called out the potential value of medium- and high-voltage DC power:

***“...[for heavy-duty EV fleets], switching to a medium/high-voltage, DC-based system could be less costly than adding a traditional solution, including the transmission, sub-transmission and distribution level cable and transformer equipment required.”***

***“This concept offers the potential to satisfy all the critical grid objectives noted above while minimizing land use in what typically are already dense transportation corridors.”*<sup>80</sup>**

SCE was also quick to call out the primary challenge with powering EV fleets from a DC-based system:

***“this [grid] architecture has not been commercially deployed elsewhere yet, and to be implemented in the long term, it will require several critical technological components to be ready and available within the next couple of decades.”*<sup>81</sup>**

In 2020, the US Department of Energy’s Office of Electricity published the “Solid-State Power Substation Technology Roadmap.”<sup>82</sup> This roadmap outlined the opportunities and challenges for solid-state power conversion technologies and identified key advancements expected in the next 5, 10, and 20 years.

Encouragingly, private companies are investing in solid-state power conversion technologies. In 2021, Amazon invested in Resilient Power—a provider of solid-state transformers to support the electrification of medium- and heavy-duty fleets. Also in 2021, Electranix announced its intentions to develop a way to support the charging of heavy-duty EVs directly from HVDC transmission lines. Last but not least,

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<sup>79</sup> Southern California Edison’s [Reimagining the Grid](#) white paper

<sup>80</sup> [Reimagining the Grid](#)

<sup>81</sup> [Reimagining the Grid](#)

<sup>82</sup> [OE Report: Solid State Power Substation Technology Roadmap](#)

a major provider of grid infrastructure is rumored to be developing a way to charge heavy-duty EVs directly from an HVDC transmission line.<sup>83</sup>

The NextGen Highways team's opinion is that entities planning for the electrification of medium- and heavy-duty fleets should evaluate scenarios where charging occurs directly from transmission infrastructure located along interstate and highway ROW.

### **Finding #7: Wisconsin has the playbook for siting transmission in DOT ROW**

Wisconsin state agencies, utilities, and regulators have successfully collaborated to place electric transmission infrastructure within and along state and interstate highway ROW over the last 20 years.

Wisconsin's Act 89, the Wisconsin Dept. of Transportation's (WisDOT) utility accommodation policy, and the Cooperative Agreement between WisDOT and the Public Service Commission of Wisconsin (PSCW) constitute a playbook that other states can benefit from when looking to accommodate transmission line projects within highway ROW. The NextGen Highways team has summarized that playbook below and developed the [Introduction to Permitting Transmission in WisDOT ROW](#) document for those interested in additional details and references.

In 2001, shortly after American Transmission Company (ATC) took over construction, maintenance, and operations of the transmission grid in much of Wisconsin, ATC and energy stakeholders realized that the state was in desperate need of transmission infrastructure development. Understanding the low likelihood of significant transmission development utilizing new ROW, ATC, regulators, and other stakeholders collaborated on minimizing potential impacts from new electric transmission.

The result was the 2003 Wisconsin Act 89. The law required that the following corridors be utilized in the following order of priority for the siting of new electric transmission facilities:

- existing utility corridors
- highway and railroad corridors
- recreational trails
- new corridors

After the passage of Act 89, the Wisconsin Department of Transportation (WisDOT) amended its utility accommodation policy to allow for the longitudinal installation of transmission lines in its interstate and highway ROW. Pursuant to federal requirements,<sup>84</sup> WisDOT's utility accommodation policy allows for the accommodation of electrical transmission infrastructure provided that it does not:

- Adversely affect the safety, efficiency, and aesthetics of the freeway
- Interfere with or impair the present use or future expansion of the freeway
- Rely on access for future maintenance directly from the freeway lanes or shoulder

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<sup>83</sup> Despite widely-held beliefs that charging EVs from an HVDC transmission line must be prohibitively expensive, multiple companies are now developing the technology required to economically serve tens or hundreds of MWs of load from medium and high-voltage DC transmission lines. Such technology would be perfect for the needs of medium- and heavy-duty fleet electrification. As one example, see [Tapping HVDC for Electrification of Rail and Heavy-Duty Transportation](#)

<sup>84</sup> [23 CFR 645 subpart B, Federal Highway Administration](#)

In 2009, as a result of Act 89, WisDOT's updated utility accommodation policy, and the development of new transmission infrastructure, WisDOT and PSCW entered into a cooperative agreement "to ensure that whenever practical, WisDOT and PSCW shall utilize existing transportation or transmission corridors instead of creating new corridors for electric transmission facilities."<sup>85</sup>

The Cooperative Agreement acknowledges Act 89 and WisDOT's utility accommodation policy. It notes that any potential conflicts between the agencies be resolved informally by primary agency contacts in a timely manner, consistent with the law and agency rules. The agreement also specifies measures to coordinate WisDOT and PSCW planning and review procedures in making respective regulatory decisions regarding the co-location of electric transmission facilities within transportation corridors, including highway and railroad ROW within the WisDOT jurisdiction.

If a route utilizing WisDOT ROW is selected as part of the project application, the utility must provide a constructability report<sup>86</sup> as part of the application to the PSCW. The utility drafts and submits the report to DOT for review and comment prior to including it in the application. The report typically includes a discussion of maintenance plans and roles and responsibilities of the utility and WisDOT.

**The legislation, policy, and agreements described above have fostered a collaborative and trusting relationship between Wisconsin utilities and WisDOT and have resulted in the efficient, cost-effective, and successful siting of over 800 miles of transmission infrastructure in and along interstate and highway ROW in Wisconsin.**

## National Recommendations

### State DOTs should:

- Site and build fiber in a way that allows for buried HVDC transmission to be co-located at a later date
- Develop and invest in their relationship with utilities, public utilities commissions, and other state agencies with transmission siting jurisdiction
- Determine the amount of operational funding required to support the co-location of electric and communications infrastructure in their ROW

### Utilities and energy developers should:

- Develop and invest in their relationship with state DOTs
- Evaluate how highway ROW (if made available) could enable the various grid investments needed to support electric vehicle charging
- Evaluate how planned regional and interregional transmission lines could benefit from highway ROW (if made available)

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<sup>85</sup> [Cooperative Agreement between the Wisconsin Department of Transportation and the Public Service Commission of Wisconsin Regarding New Electric Transmission Lines](#)

<sup>86</sup> [American Transmission Company and Xcel Energy Constructability Report](#)

### Governors should consider:

- Supporting and facilitating the implementation of Wisconsin's co-location playbook
- Working with their DOT, utilities, and legislature to remove any statutory barriers in state law
- Evaluating options to provide their DOT with operational funding to support the co-location of electric and communications infrastructure in the ROW

### Next Step for NextGen Highways

Given the positive findings from this Feasibility Study, the NextGen Highways Team is planning to launch a NextGen Highways Coalition to support the co-location of buried fiber and transmission in highway and interstate ROW.

The NextGen Highways Coalition will do the following:

- Facilitate conversations between state DOTs, utilities, and governors
- Facilitate conversations between state DOTs, utilities, and technology vendors
- Review states' highway ROW siting and permitting regulations, identify barriers to co-location, and work with stakeholders to overcome barriers
- Share insights and best practices across states
- Provide a platform through which tribes, communities, nonprofits, cities, and companies can understand the required transformation of the national highway system
- Foster public/private partnerships to build out the required infrastructure

Interested parties can email [morgan@buildngi.com](mailto:morgan@buildngi.com) and [laura@theray.org](mailto:laura@theray.org) for more information.



## Conclusion

Across the country, state DOTs are assessing both their immediate and future needs. Many are planning how they can meet these needs using new federal infrastructure funding. The US Department of Transportation has provided clear guidance that it will prioritize projects that leverage these funds to bring other benefits to the state, such as expanded broadband and expanded electric transmission.

MnDOT is well-positioned to access these new funds. In this report, we have sought both to identify the many benefits of using highway ROW for other linear infrastructure and to address concerns and questions raised by MnDOT's experienced professional staff.

At a macro level, opening up interstate and highway ROW to communications and electric infrastructure will ensure Minnesota remains strong and competitive in a global economy by expanding robust broadband access and enabling clean energy development.

This infrastructure will also bring specific benefits for MnDOT. A modern highway system will need advanced communications. It will also need clean, reliable electric power as it prepares for the wave of autonomous vehicles and the needs of electric vehicles, including medium- and heavy-duty vehicle fast charging at scale. Projects in North Carolina and Pennsylvania, as mentioned above in Part 2, offer good examples of these synergies.

Coordinating with utilities to deploy buried HVDC transmission in the highway ROW offers several benefits, including increased resilience and significant carbon emissions reductions without changing the viewscape. Expanded transmission will be vital for electrifying transportation in the most cost-effective manner.

The traditional thorny issue of building linear infrastructure on private property can be mitigated with undergrounding the transmission along existing highway and rail corridors. Burying HVDC transmission can be done at a similar cost to conventional overhead AC transmission while providing critical reliability and resilience benefits. Furthermore, the potential for accelerated permitting timelines for buried transmission projects would be worth billions of dollars in avoided carbon emissions.

The findings from this study demonstrate that buried HVDC transmission is cost-effective and can be feasibly sited in interstate and highway ROW after making appropriate consideration of existing and future transportation system needs. While the study identified challenges, none appear to pose insurmountable barriers.

The NextGen Highways Team and MnDOT believe that this report will provide a solid foundation as MnDOT considers actively removing barriers to siting buried HVDC transmission in interstate and highway ROW in 2022.



# Appendix A: Existing Plans, Policies, Practices, and Projects that Informed This Work

Various plans, policies, practices, and projects were reviewed and informed this Feasibility Study. The resources listed below were chosen based on their relevance of applying the NextGen Highways vision in Minnesota. Additional documents may be reviewed during future study.

## Minnesota Statewide Strategic Documents

- Annual Report of the Governor's Task Force on Broadband (December 2020)
- Sec. 116J.391 Minnesota Statutes (Dig Once Policy, 2020)
- Climate Change Executive Order 19-37 (December 2019)
- Our Minnesota Climate, Legislative Priorities for 2021
- Minnesota IT Services (MNIT) 2020 Strategic Plan
- Statutory Siting Guidance for High Voltage Transmission Lines (HVTL) in MN

## MnDOT Strategic Plans

- Minnesota GO
- Statewide Multimodal Transportation Plan (SMTP) (January 2017)
- Sustainable Transportation Advisory Council (STAC) Charter and Recommendations (2020)
- Sustainability and Public Health Division 2020 Strategic Plan
- CAV Strategic Plan
- Statewide ITS Plan
- MN Governor's Broadband Task Force 2020 Report

## MnDOT Policies

- MnDOT Fiber Optic Infrastructure and RTMC Network Access Policy (August 2021)
- Minnesota Statutes § 161.45; 161.46, subd. 2; 237.163, subd. 2(b) (2021)
- Right of Way Manual (July 2018)
- Utility Accommodation Manual (March 2016)
- Minnesota Manual on Uniform Traffic Control Devices (MN MUTCD), Part 6 Temporary Traffic Control (December 2019)
- Minnesota Administrative Rules Part 8810.3300 (2012)

## Wisconsin

- WisDOT and ATC successfully permitting transmission infrastructure in DOT ROW
- Act 89 in WI
- DOT Utility Accommodation Policy
- DOT and PSCW Cooperative Agreement on New Electric Transmission Lines

## Transmission Projects in the US

- SOO Green HVDC Link: a buried HVDC transmission line from Iowa to Illinois that uses railroad and highway ROW
- Badger Coulee Transmission Line: an overhead AC transmission line in Wisconsin that uses highway ROW, including interstate ROW (I-94/I-90)
- Clean Path NY: a buried HVDC transmission line in New York that utilizes rail and road ROW and waterway
- Champlain Hudson Power Express: a buried HVDC transmission line in New York that utilizes rail and road ROW and waterway

## Transmission Projects in Europe

- SuedLink: a buried HVDC transmission line in Germany
- SuedOst Link: a buried HVDC transmission line in Germany
- France-Italy Interconnection: a buried HVDC transmission line in France and Italy that utilizes highway ROW

## MISO

- Long Range Transmission Plan

## Federal

- FHWA, State DOTs Leveraging Alternative Uses of the Highway Right of Way Guidance (April 2021)
- FHWA Policy on Using Bipartisan Infrastructure Law Resources to Build a Better America (December 2021)