APPENDIX F

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

COMMENTS OF THE DEPARTMENT OF COMMERCE – DIVISION OF ENERGY RESOURCES AND THE MINNESOTA PUBLIC UTILITIES COMMISSION – ENERGY INFRASTRUCTURE PERMITTING STAFF ON THE DRAFT APPLICATION

COMMERCE DEPARTMENT

December 11, 2025

Kodi Verhalen
Taft Law
8th Street South
Minneapolis, Minnesota 55402

RE: **Letter from the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E015/CN-25-111

Dear Ms. Verhalen:

The Minnesota Department of Commerce has reviewed the Draft Petition for the combined *Certificate of Need and Route Permit Application for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Project* and offers the following feedback:

- An application completeness checklist as part of the application itself (not an appendix) for both the Certificate of Need and Route Permit should be included.
- A brief summary of filing on separate page is required.
- Section 1.2
  - Please simplify this section and include whether or not this project appeared in an Integrated Resource Plan or Biennial Transmission Project.
- Table 3 must be completed.
- Section 2.4.3
  - This section needs a brief introduction to MISO and MISO's role in project selection, cost recovery, and rates. This also gives precedent for the MISO discussion in section 3.
  - A citation that refers to the rule should be added to this sentence: "The Commissioner's rules require an applicant to provide the annual revenue requirements to recover the costs of a proposed project.".
- Section 3.2.2
  - We are not disputing the following paragraph, but these are bold claims and may not be indicative of what is occurring in Minnesota:

    > While the transmission grid remains extremely reliable, in recent years, extreme weather, wildfires, and sabotage have had an increasing impact on the power grid across the United States. As a result, owners and operators of the transmission grid, including the Applicants, are seeking new ways to increase the resilience of the transmission grid to better prevent, withstand, and recover from low probability but high impact events. Resilience efforts include the use of stronger transmission structures, new conductors which minimize icing, enhanced security measures, and other physical and non-physical improvements"
  - Text should be added to distinguish how these risks (extreme weather, wildfires, sabotage) apply to Minnesota versus the United States.

- Section 3.11
    - Consider including other social benefits such as a reduction in transmission congestion and therefore reliable electricity and affordable electricity rates for consumers.
- Section 4.2
    - A definition of “reactive resources” should be added.
- Section 4.3
    - A map of the facilities in Table 20 should be provided for additional context.
- Section 6.4.1
    - Provide more detail regarding the service life of the proposed project.

Please do not hesitate to reach out to discuss our comments.

Sincerely,

/s/ Sydnie Lieb, Ph.D.
Assistant Commissioner, Office of Regulatory Analysis

DZ, SR

Topic	Statutory Requirement	Location in Document	Applicants' Response
Project ownership	**216I.05, subd. 3(b)(1)**	**2.3**	
This section meets staff expectations. The Project will be owned by both Minnesota Power and American Transmission Company.			**No response required.**
Permittee name	**216I.05, subd. 3(b)(2)**	**1.9**	
This section meets staff expectations. Minnesota Power and American Transmission Company will be the permittees.			**No response required.**
Project description	**216I.05, subd. 3(b)(3)**	**2.1**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends being explicit and consistent as to how many circuits are being proposed for each segment through this permit request throughout the application. Project descriptions should be consistent throughout the application and contain all of the same information. Staff also recommends adding clarifying statements about what substation expansion is proposed under this project.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Environmental Information, generally	**216I.05, subd. 3(b)(4) and subd. 4(a)**	**Section 2 of Appendix G**	
See resource-specific discussions. Support conclusions on environmental impact intensity with discussions of rationale used to inform those conclusions.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Identification of Property Owners	**216I.05, subd. 3(b)(5), as described in 216I.05, subd. 8 (3)**	**Appendix T**	
The information provided meets staff expectations.			**No response required.**
Maps	**216I.05, subd. 3(b)(6)**	**Appendix I**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff offers the following general comments on the maps provided in Appendix I: • Include maps illustrating the project in the body of the application to illustrate the project for the reader • The tribal land and ROW colors in all maps are too similar to differentiate. • All maps need to be updated to properly show the entire footprint of all substations with polygons rather than points so viewers can see where the proposed routes enter the substations Staff offers the following comments on the figures provided in the application text: • Figure 1 has an inset map showing a blank area that is not described in section 1.3. • Figure 2 is blurry and needs to be higher resolution. • Recommend changing Figure 3 title to be the same as the title within the map and Figure 2: "Service Territory". If you merge the application and EA, delete any repeating figures.			**The Applicants have added additional maps in line with the Application text. The Application also contains bookmarks to allow for accessible navigation to Appendix I for readers. Revisions have been made to the figures as requested.**
Existing ROWs	**216I.05, subd. 3(b)(7)**	**Appendix I**	
The information provided meets staff expectations.			**No response required.**
Project design, including required ancillary facilities	**216I.05, subd. 3(b)(8)**	**2.1.4 and 2.1.5**	
Staff provided technical edits and comments to improve the clarity of this section. Staff asks that the applicant include a dedicated design section with their final application for readability and clarity. Staff also recommends providing images to illustrate typical structures discussed in this section for the reader.			**The information required by the statute is provided in the Application and in Appendix H. The Application will be filed with the Appendices bookmarked for readily-accessible navigation.**
Project cost	**216I.05, subd. 3(b)(9)**	**2.4**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
No project cost estimates were provided with the draft application. Minnesota Statute 216I.05, subd. 3(b)(9) requires the application contain "a cost analysis of the proposed large energy infrastructure facility, including the costs to construct, operate, and maintain the facility." Please review PUC's Data Practices Policy on Not Public Data in Commission Proceedings if you believe some of the information is protected from public disclosure under chapter 13. If information is protected from public disclosure, you may file a redacted public and a nonredacted TS version according to our policy.			**Placeholders for this information were included in the draft of the Application reviewed by PUC-EIP. All information required by Minn. Stat. § 216I.05, subd. 3(b)(9) has been included in the Application.**
Design for expansion	**216I.05, subd. 3(b)(10)**	**2.2**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Site or ROW acquisition, construction, maintenance, & restoration	**216I.05, subd. 3(b)(11)**	**6.0**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**No response required.**
Other Permits	**216I.05, subd. 3(b)(12)**	**8.0**	
This section meets staff expectations.			**No response required.**
CN Requirement	**216I.05, subd. 3(b)(13)**	**1.6**	
This section meets staff expectations.			**No response required.**
Other sites or routes considered	**216I.05, subd. 3(b)(14)**	**4.0**	
This section meets staff expectations.			**No response required.**
Additional information required by rule	**216I.05, subd. 3(b)(15)**	**5.1**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff recommends the applicants clarify whether the project avoids the prohibited routes identified in Minn. R. 7850.4300.			**This information has been added to Section 5.1 of the Application.**
Tribal coordination	**216I.05, subd. 3(b)(16)**	**7.0, Appendix F and Q**	
The notification letter provided in Appendices F and Q contains project mileage that is inconsistent with what is in the application. Please edit the letter to reflect the current project layout and ensure that notice is provided to the "Tribal Government Contacts" and "Tribal Historic Preservation Officers" service lists in eDockets. The Commission's July 2025 Guidance for Successful Tribal Engagement (Tribal guidance) is on the Commission's website. As discussed in the Commission's Tribal guidance, a single email or postal letter about a project does not suffice as coordination. Applicants must document that they have made reasonable efforts to coordinate with each tribe with multiple methods and attempts when a response isn't received. Staff requests the applicants reach out again to the Tribal Historic Preservation Officers for the eight Minnesota tribes who did not respond with a follow up email and, if that is not successful, a phone call. Document these attempts for inclusion in the filed application.			**The notification letter at Appendix D and Appendix O[1] included the information known about the Project at the time the letter was sent, which needed to be provided early enough in the development process to solicit and receive feedback from the recipients. As is consistent with routing practice, feedback received and additional analysis during the route development process often leads to changes in a final route proposed in an application. Once the Application is deemed complete, notice of the Project, including its current configuration, will be provided by the Commission under Minn. Stat. § 216I.05, subd. 8, including to Tribal Nations. The Applicants have undertaken coordination with Tribal Nations and will continue that coordination in the future.** **The Applicants have already followed up with Tribal Nation contacts, including the Tribal Historic Preservation Officers. This is discussed in Section 7.2 of the Application.**

[1] Note that the Appendices were numbered differently in the draft reviewed by PUC-EIP. The Appendix references in the Applicants' Response align with the as-filed application.

Topic	Statutory Requirement	Location in Document	Applicants' Response
Preapplication Coordination (LGUs)	**216I.05, subd. 5 (1)**	**7.4, Appendix F**	
The notification letter provided in Appendix F contains project mileage that is inconsistent with what is in the application. Staff asks that the letter be edited to reflect the current project layout and re-sent to local government unit contacts.			**The notification letter at Appendix D included the information known about the Project at the time the letter was sent, which needed to be provided early enough in the development process to solicit and receive feedback from the recipients. As is consistent with routing practice, feedback received and additional analysis during the route development process often leads to changes in a final route proposed in an application. Once the Application is deemed complete, notice of the Project, including its current configuration, will be provided by the Commission under Minn. Stat. § 216I.05, subd. 8, including to LGUs. The Applicants have undertaken coordination with LGUs and will continue that coordination in the future.**
Preapplication Coordination (State Technical Resource Agencies)	**216I.05, subd. 5 (3)**	**7.3, Appendix F and R**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
The notification letter provided in Appendices F and R contains project mileage that is inconsistent with what is in the application. Staff asks that the letter be edited to reflect the current project layout and ensure that notice is provided to the "Agency Reps" service list in eDockets.			**The notification letter at Appendix D and Appendix P included the information known about the Project at the time the letter was sent, which needed to be provided early enough in the development process to solicit and receive feedback from the recipients. As is consistent with routing practice, feedback received and additional analysis during the route development process often leads to changes in a final route proposed in an application. Once the Application is deemed complete, notice of the Project, including its current configuration, will be provided by the Commission under Minn. Stat. § 216I.05, subd. 8, including to Agency Representatives. The Applicants have undertaken coordination with Agency Representatives and will continue that coordination in the future.**
Environmental setting	**216I.05, subd. 4(a)(1)**	**2.0 of Appendix G**	
If you merge the application and EA, staff suggest deleting repetitive project information in this section that is not relevant to the environmental setting.			**The EA is maintained at Appendix G. As the statute does not require the EA to be within the Application, itself, the Applicants elected to provide the EA as an appendix to the Application.**
Human settlement, generally	**216I.05, subd. 4(2)**	**2.1 of Appendix G**	
See resource-specific discussions.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Public health & safety including EMF	**216I.05, subd. 11(b)(1) (Decision Criteria)**	**2.2 of Appendix G**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-CIP comments and incorporated revisions as appropriate.**
Displacement	**216I.05, subd. 4(a)(2)**	**2.1.1 of Appendix G**	
Information presented in section 2.1.1 of Appendix G discusses displacement, but the section is titled "Proximity of Project to Residences". Staff recommend changing the title to "Displacement" to align with statute and application guidance.			**The Project is not anticipated to displace residences. Instead, this section of the EA is intended to communicate to interested persons the proximity of the Project to residences. Therefore, the title was not changed as PUC-EIP requests.**
Noise	**216I.05, subd. 4(a)(2)**	**2.1.2 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends discussing impacts of increased traffic noise during construction, and impacts of long-term noise associated with vegetation maintenance. If the project is expected to exceed noise limits, describe mitigation measures to address this. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Aesthetics	**216I.05, subd. 4(a)(2) 216I.19 (turbine lighting)**	**2.1.3 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of the substation expansion activities and associated aesthetic impacts. Otherwise, this section meets staff expectations. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Socioeconomic Impacts	**216I.05, subd. 4(a)(2); 216I.05, subd. 11(b)(14)**	**2.1.4 of Appendix G**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff provided technical edits and comments to improve the clarity of this section. The draft does not include discussion of potential impacts and mitigation measures specific to socioeconomics. Staff recommends the applicants provide separate sections within socioeconomics to discuss potential impacts and mitigation measures. Staff also recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Environmental Justice Impacts	**216I.05, subd. 4(a)(2); 216I.05, subd. 11(a)(3)**	**2.1.4 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section, and additional sources to support impacts discussion. Staff recommends the applicants provide a discussion of any possible negative impacts related to environmental justice.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Cultural Values	**216I.05, bud. 4(a)(2)**	**2.1.5 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Recreation	**216I.05, subd. 4(a)(2)**	**2.1.6 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of the substation expansion activities and associated impacts, and a discussion of impacts from dust, winter construction regarding the snowmobile trail, state forest land, and increased traffic near recreation areas. Staff also recommends discussing the long-term impacts of vegetation clearing on the recreational experience of resource users. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**

Topic	Statutory Requirement	Location in Document	Applicants' Response
Public Services	**216I.05, subd. 4(a)(2)**	**2.1.7 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Land Use	**216I.05, subd. 11(a)(2)**	**2.3 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends more thoroughly assessing impacts of the proposed tree clearing on state forest land.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Land-based economics, generally	**216I.05, subd. 4(a)(3)**	**2.4 of Appendix G**	
See resource-specific discussions.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Agriculture	**216I.05, subd. 4(3); 216I.05, subd. 11(b)(5) and (9); see also Minn. R. 7850.4400, subp. 4.**	**2.4.1 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Forestry	**216I.05, subd. 4(3)**	**2.4.2 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommend providing more detail to support conclusions on impact intensity. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Mining	**216I.05, subd. 4(a)(3)**	**2.4.4 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Tourism	**216I.05, subd. 4(a)(3)**	**2.4.3 of Appendix G**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Archaeological & historic resources	**216I.05, subd. 4(4)**	**2.5 of Appendix G**	
Staff noted project mileage discrepancies with the Phase 1a Literature Review provided in Appendix U, the notification letters to agencies in Appendix R, and the application. The Literature Review and notification letters also do not include Segment 3, as proposed in the Application. The documents and coordination need to be updated to reflect the current proposed project layout for the final application submittal. Staff provided technical edits and comments to improve the clarity of this section. Staff recommends discussing all coordination that has happened or is planned with SHPO and OSA.			**The notification letter at Appendix S and Appendix P included the information known about the Project at the time the letter was sent, which needed to be provided early enough in the development process to solicit and receive feedback from the recipients. As is consistent with routing practice, feedback received and additional analysis during the route development process often leads to changes in a final route proposed in an application. Once the Application is deemed complete, notice of the Project, including its current configuration, will be provided by the Commission under Minn. Stat. § 216I.05, subd. 8, including to SHPO. Additionally, what is referred to as "Segment 3" in the Application was included in the Phase 1a Literature Review, but was part of Segment 2 at the time.** **The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Natural environment impacts - generally	**216I.05, subd. 4(5)**	**2.6 of Appendix G**	
See resource-specific discussions.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**

Topic	Statutory Requirement	Location in Document	Applicants' Response
Air quality	**216I.05, subd. 4(a)(5)**	**2.6.1 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of fugitive dust impacts and other impacts related to temporary access roads. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Geology	**216I.05, subd. 4(a)(5); 216I.05, subd. 11(b)(1)**	**2.6.4 and 2.7.2 of Appendix G**	
This section meets staff expectations.			**No response required.**
Groundwater	**216I.05, subd. 4(a)(5); 216I.05, subd. 11(b)(1)**	**2.6.4 and 2.7.2 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of impacts related to fuel spills and contaminant leaks from equipment. Staff also recommends discussion of impacts from the substation expansion activities. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Soils	**216I.05, subd. 11(b)(1) and subd. 11(b)(5)**	**2.7.3 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including data on soil wind and water erodibility, compaction-prone soils, and hydric soils present. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Surface waters (including stormwater, floodplains, and wetlands)	**216I.05, subd. 4(5); 216I.05, subd. 11(b)(1)**	**2.6.4 of Appendix G**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of impacts from temporary bridges discussed in 2.6.4.2.3. Staff also recommends discussing impervious surfaces added for the substation expansion activities in section 2.6.4.2.4 and generally discussing impacts of the substation expansion activities in 2.6.4.2.5. Add a discussion about impacts to stream crossings from riparian vegetation removal and if/how you plan to restore these areas with native seed mixes. Also discuss impacts to the Sax Zim Bog in the Wetlands impacts discussion. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Vegetation	**216I.05, subd. 4(5)**	**2.6.5 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of impacts related to the substation expansion activities. Staff also recommends describing in text and including a map of where vegetation clearing will occur. The vegetation section does not contain a mitigation discussion. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Wildlife	**216I.05, subd. 4(5)**	**2.6.6 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of impacts related to lighting and fencing proposed for the substation expansion activities. Staff also recommends adding discussion of impacts to the Sax Zim Bog and impacts of riparian vegetation clearing on aquatic wildlife and habitats. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Rare and unique resources	**216I.05, subd. 4(8)**	**2.6.8 of Appendix G**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends discussing designated trout streams and associated impacts of crossing them (spanning or directional boring). Staff also recommends discussing potential impacts on Sites of Biodiversity Significance. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Greenhouse gases	**216I.05, subd. 4(6)**	**2.6.3 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommend GHG calculations be provided for land use conversion due to the acreage of vegetative removal. Otherwise, this section meets staff expectations. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Climate change resilience	**216I.05, subd. 4(7)**	**2.6.2 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Staff recommends including a discussion of impacts regarding vegetation removal and associated riparian vegetation clearing in relation to water temperatures. Staff also recommends discussing impacts of tree clearing in relation to increased potential for runoff and flooding, release of stored carbon, and how future carbon capture will be affected. Staff recommends the final application discuss mitigation measures required by Commission permits as well as mitigation measures permittees will implement above and beyond permit requirements.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Unavoidable Impacts	**216I.05, subd. 4(9)**	**2.9 of Appendix G**	
Staff provided technical edits and comments to improve the clarity of this section. Otherwise, this section meets staff expectations.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Irretrievable and Irreversible Impacts	**216I.05, subd. 11(b)(11)**	**2.10 of Appendix G**	

Topic	Statutory Requirement	Location in Document	Applicants' Response
This section meets staff expectations.			**No response required.**
Cumulative Potential Effects	**216I.05, subd. 11(a)(2) and (b)(2)**	**n/a**	
The Commission is charged with evaluating the potential human and environmental impacts of sites and routes including impacts related to possible future development or expansion in the project area. Staff interprets this charge to be an evaluation of cumulative potential effects associated with the Project. The draft does not include a discussion of cumulative impacts. EIP staff recommends the application filed in eDockets discuss reasonably foreseeable projects in the vicinity of the Project and the potential interactions between the Project and other reasonably foreseeable projects with respect to human and environmental impacts.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**
Mitigation Measures	**216I.05, subd. 4(10)**	**Section 2 of Appendix G**	
Staff provided comments on mitigation in each resource sections in the redline copy of the application. In general, you should describe in your application mitigation measures typically required by Commission permits and also identify additional mitigation measures you propose that may become special conditions of a future permit.			**The Applicants reviewed PUC-EIP comments and incorporated revisions as appropriate.**

APPENDIX G

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

DETAILED ROUTE MAPS AND FIGURES

LIST OF MAPS

Map 1 – ISA Project

Map 2 – Minnesota Power Service Territory

Map 3 – ATC Service Territory

Map 4 – Study Area

Map 5 – Preliminary Route

Map 6 – Proposed Route

Map 7 – Segment 1

Map 8 – Segment 2

Map 9 – Segment 3

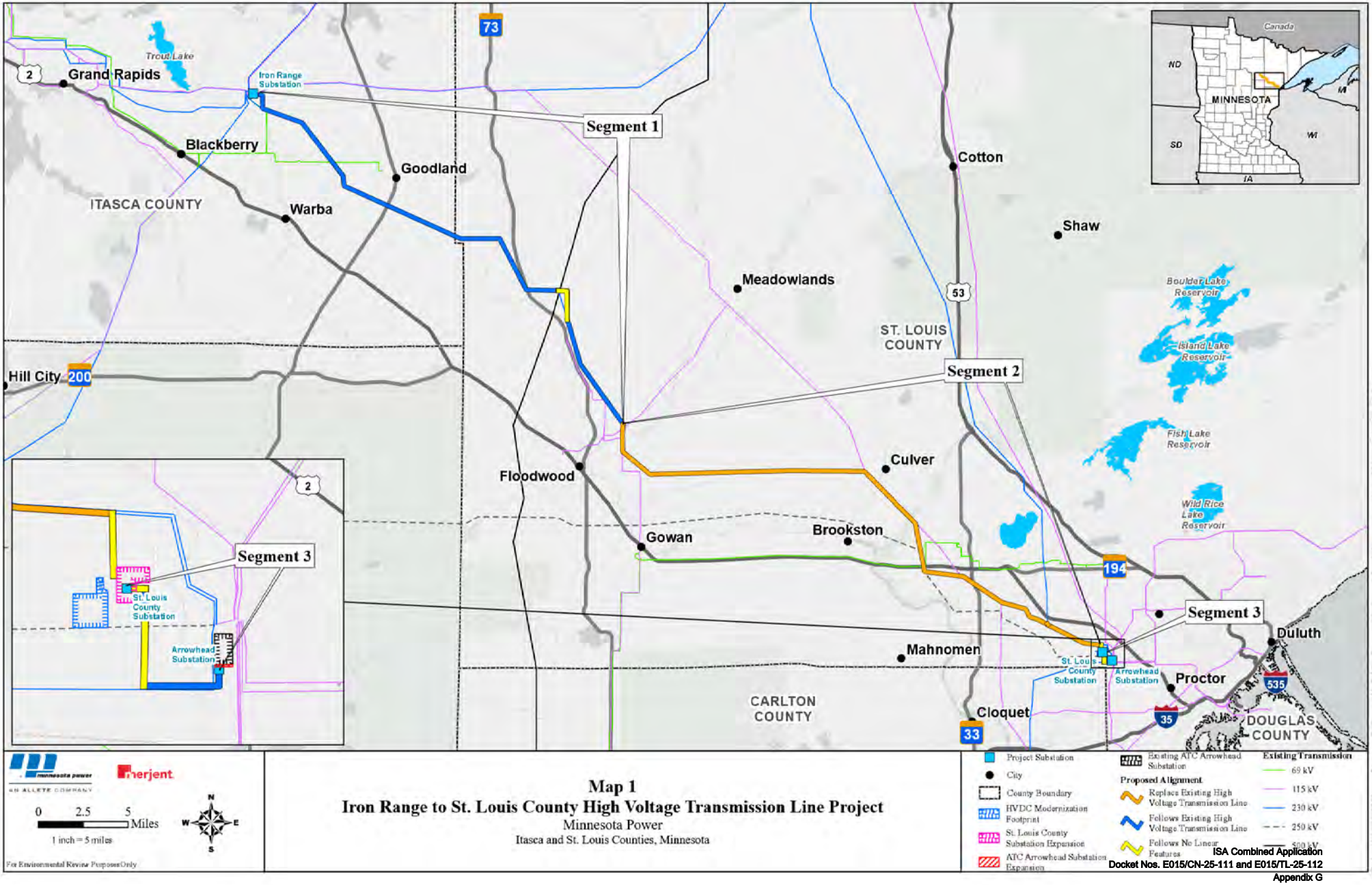
Map 10 – Rejected Alternatives

Map 11 – 9 Line Alternative

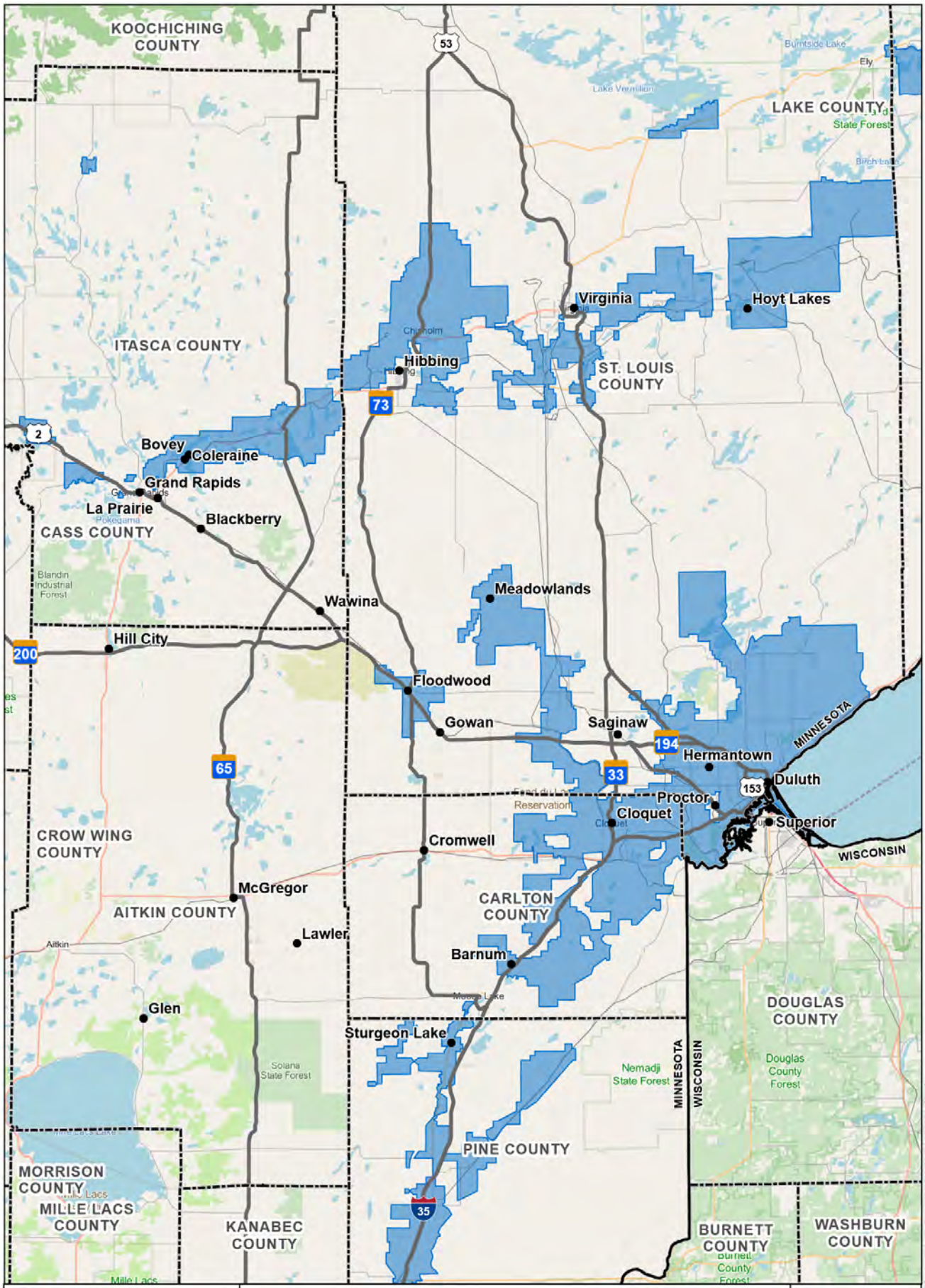
Map 12 – STL River Alternative

Map 13 – US Hwy 2 Alternative

Map 14 – Existing 9 Line to SLC Sub Alternative

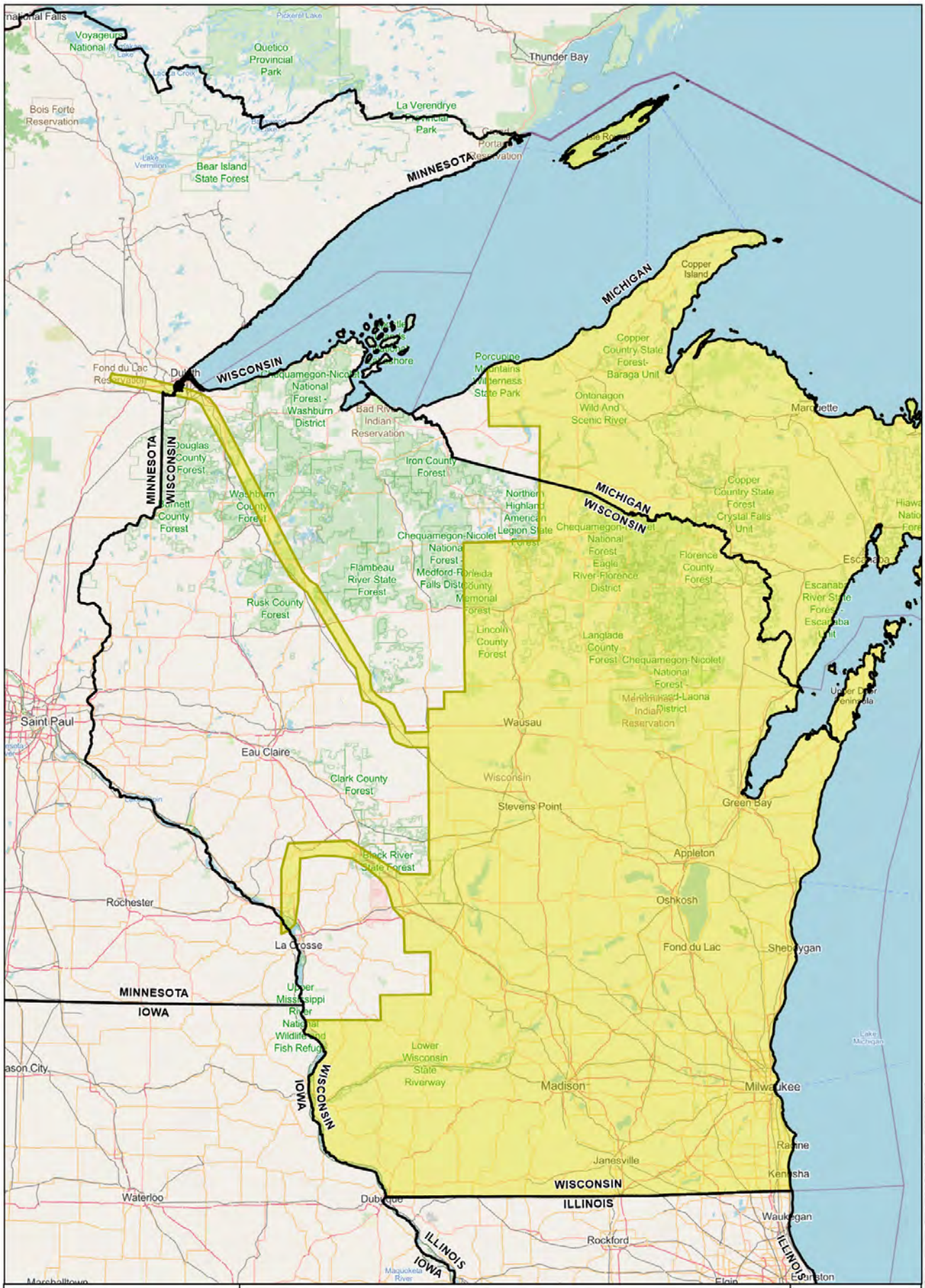


Map 1
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota



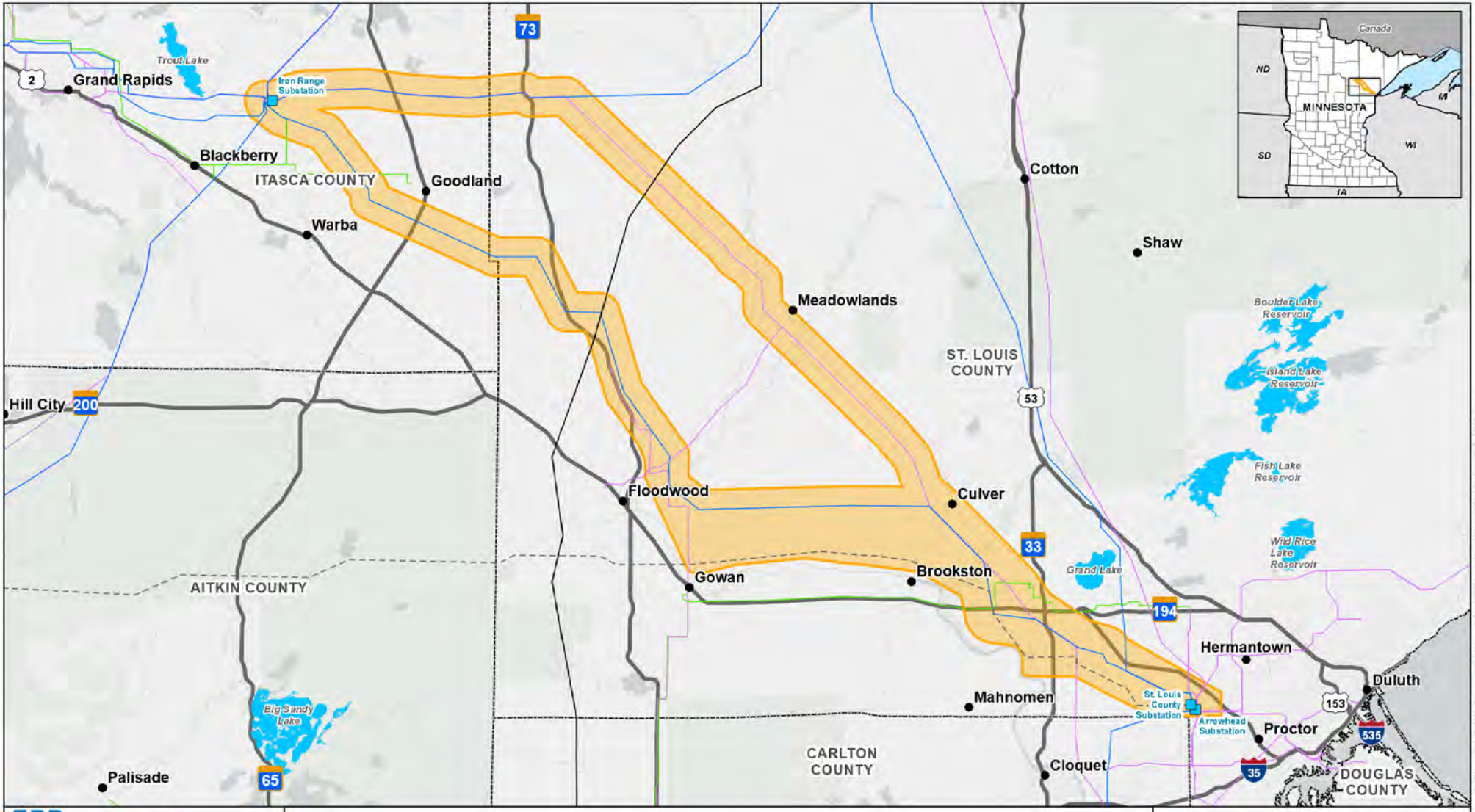
Map 2: Minnesota Power Service Territory
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power

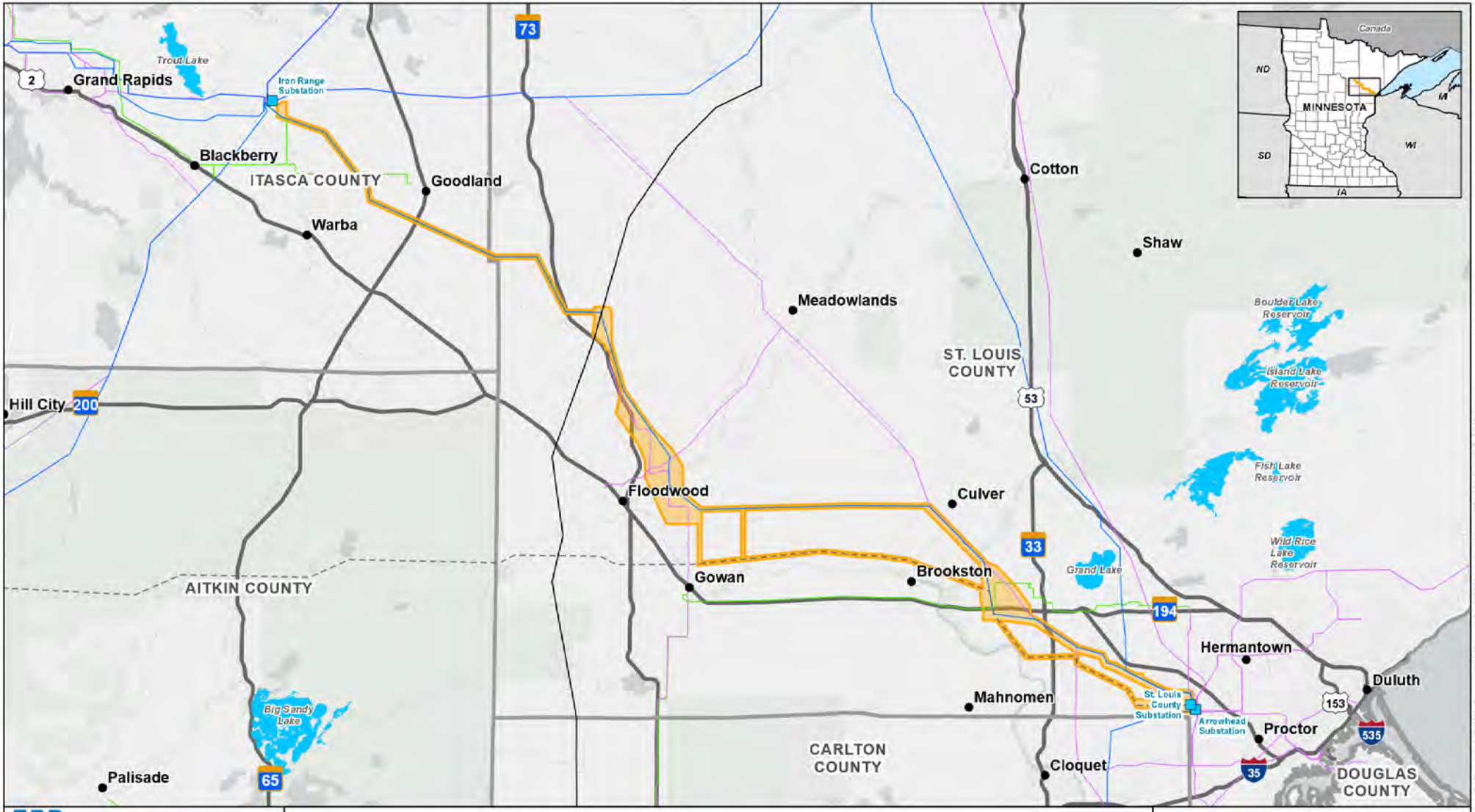
Minnesota Power Service Territory



Map 3: ATC Service Territory
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power

ATC Service Territory


Trout Lake
Grand Rapids
Iron Range Substation
Blackberry
ITASCA COUNTY
Goodland
Warba
Meadowlands
Cotton
Shaw
ST. LOUIS COUNTY
Hill City
Floodwood
Culver
Gowan
Brookston
AITKIN COUNTY
Boulder Lake Reservoir
Island Lake Reservoir
Fish Lake Reservoir
Wild Rice Lake Reservoir
Grand Lake
Hermantown
Duluth
Mahnomen
St Louis County Substation
Arrowhead Substation
Proctor
Cloquet
CARLTON COUNTY
DOUGLAS COUNTY
Big Sandy Lake
Palisade
Canada
MINNESOTA
ND
SD
IA
WI
M
73
2
200
53
33
194
153
535
35
65
0 2.5 5 Miles
1 inch = 5 miles
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Map 4: Project Study Area
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota
Project Substation
City
County Boundary
Study Area
Existing Transmission
69 kV
115 kV
230 kV
250 kV



minnesota power
AN ALLETE COMPANY

merjent

0 2.5 5 Miles

1 inch = 5 miles

N W E S

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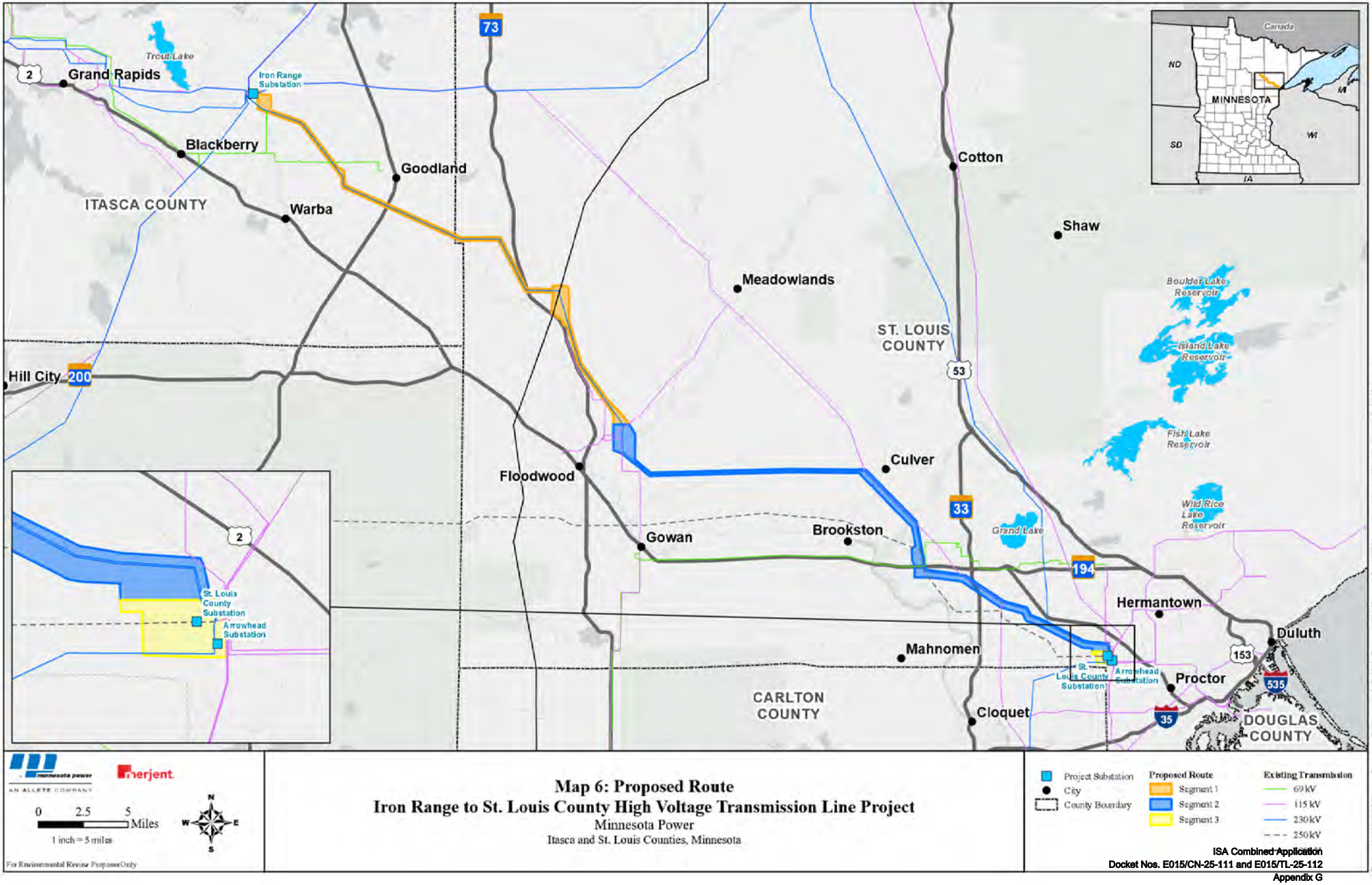
Map 5: Preliminary Route
Iron Range to St. Louis County High Voltage Transmission Line Project

Minnesota Power

Itasca and St. Louis Counties, Minnesota

Project Substation
City
County Boundary
Preliminary Route

Existing Transmission
69 kV
115 kV
230 kV
250 kV
345 kV



minnesota power
AN ALLETE COMPANY

merjent

0 2.5 5 Miles

1 inch = 5 miles

N W E S

For Environmental Review Purposes Only

Map 6: Proposed Route
Iron Range to St. Louis County High Voltage Transmission Line Project

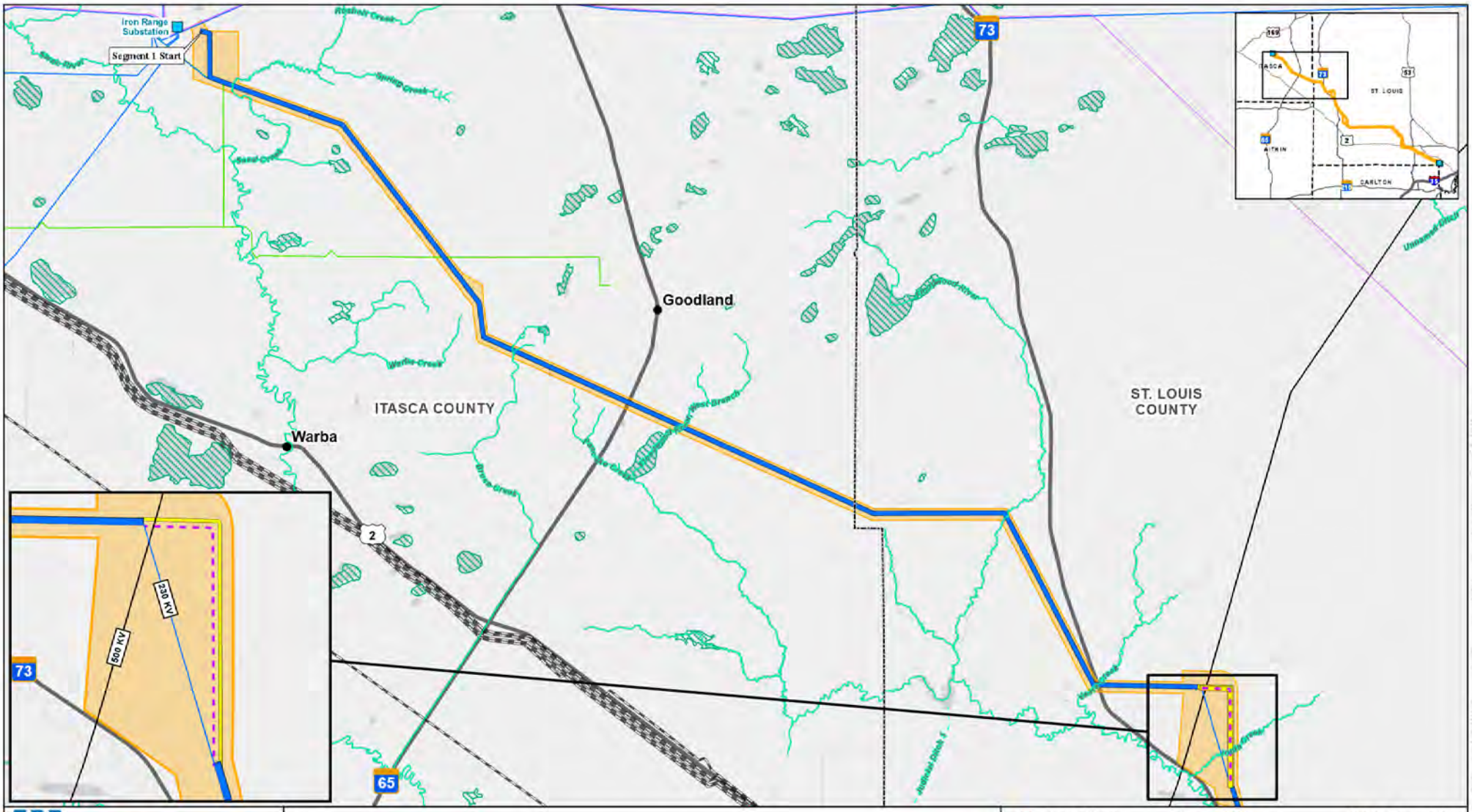
Minnesota Power

Itasca and St. Louis Counties, Minnesota

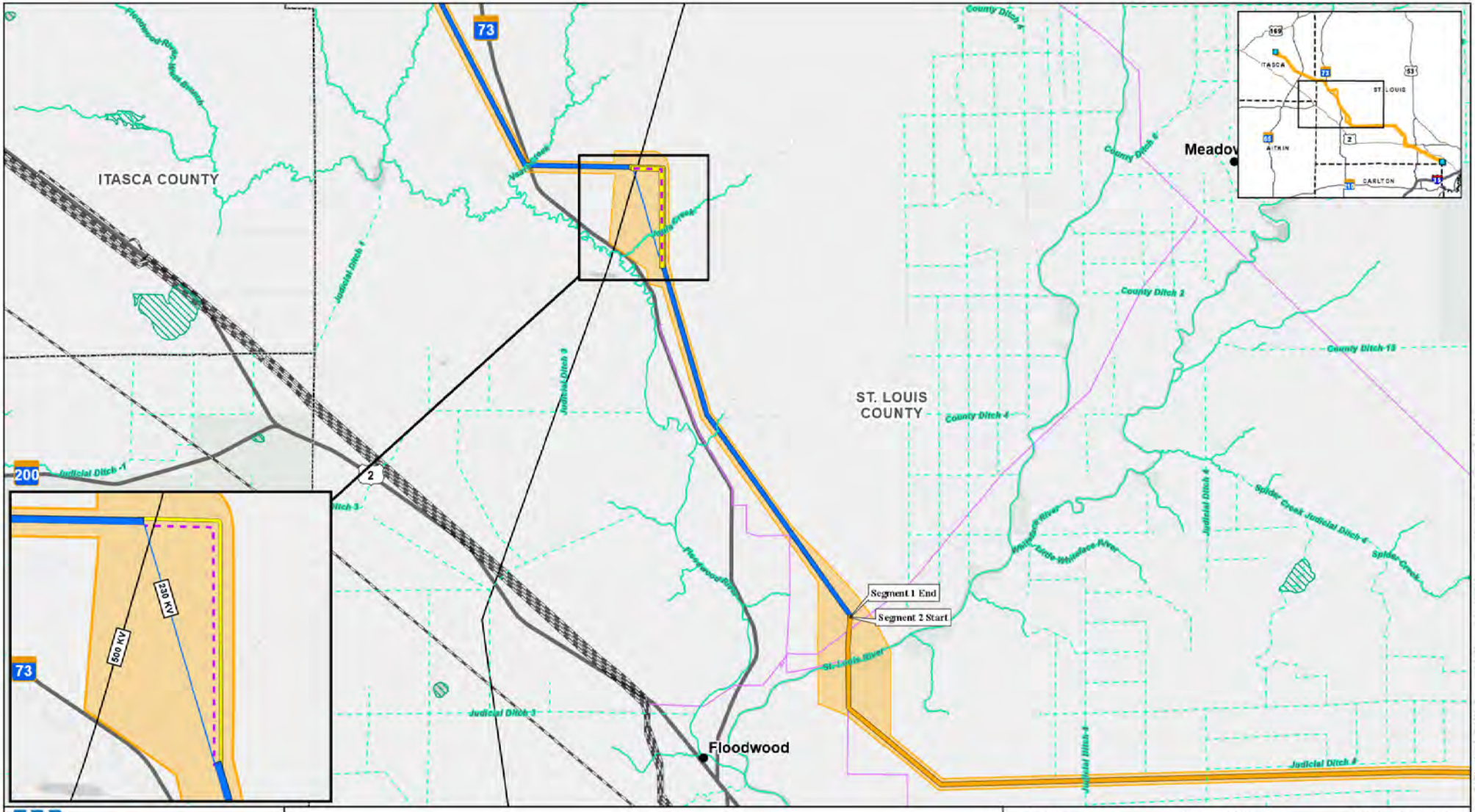
Project Substation
City
County Boundary

Proposed Route
Segment 1
Segment 2
Segment 3

Existing Transmission
69 kV
115 kV
230 kV
250 kV



Map 7: Segment 1 Proposed Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota



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merjent

0 1 2 Miles

1 inch = 2 miles

N W E S

For Environmental Review Purposes Only

Map 7: Segment 1 Proposed Route
Iron Range to St. Louis County High Voltage Transmission Line Project

Minnesota Power

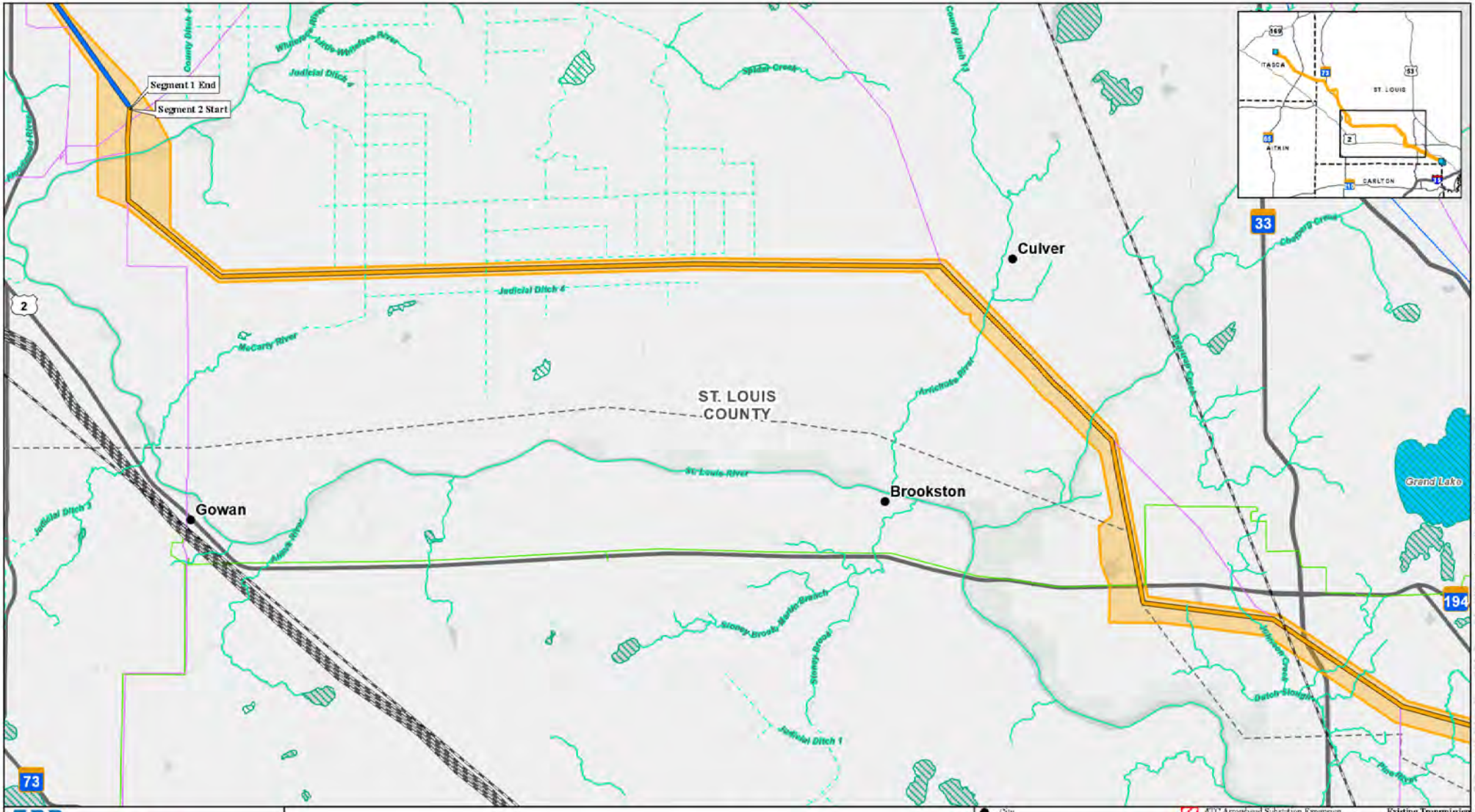
Itasca and St. Louis Counties, Minnesota

Page 2 of 2

- City
- Existing Pipeline
- Public Waters Basin/Wetland
- Public Water Watercourse
- Public Water Ditch
- Proposed Route
- County Boundary

Proposed Alignment
- Replace Existing High Voltage Transmission Line
- Follows Existing High Voltage Transmission Line
- Follows No Linear Features
- Untie Existing 230 kV

Existing Transmission
- 115 kV
- 230 kV
- 500 kV



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AN ALLETE COMPANY

Enerjent

0 1 2 Miles

1 inch = 2 miles

N W E S

For Environmental Review Purposes Only

Map 8: Segment 2 Proposed Route
Iron Range to St. Louis County High Voltage Transmission Line Project

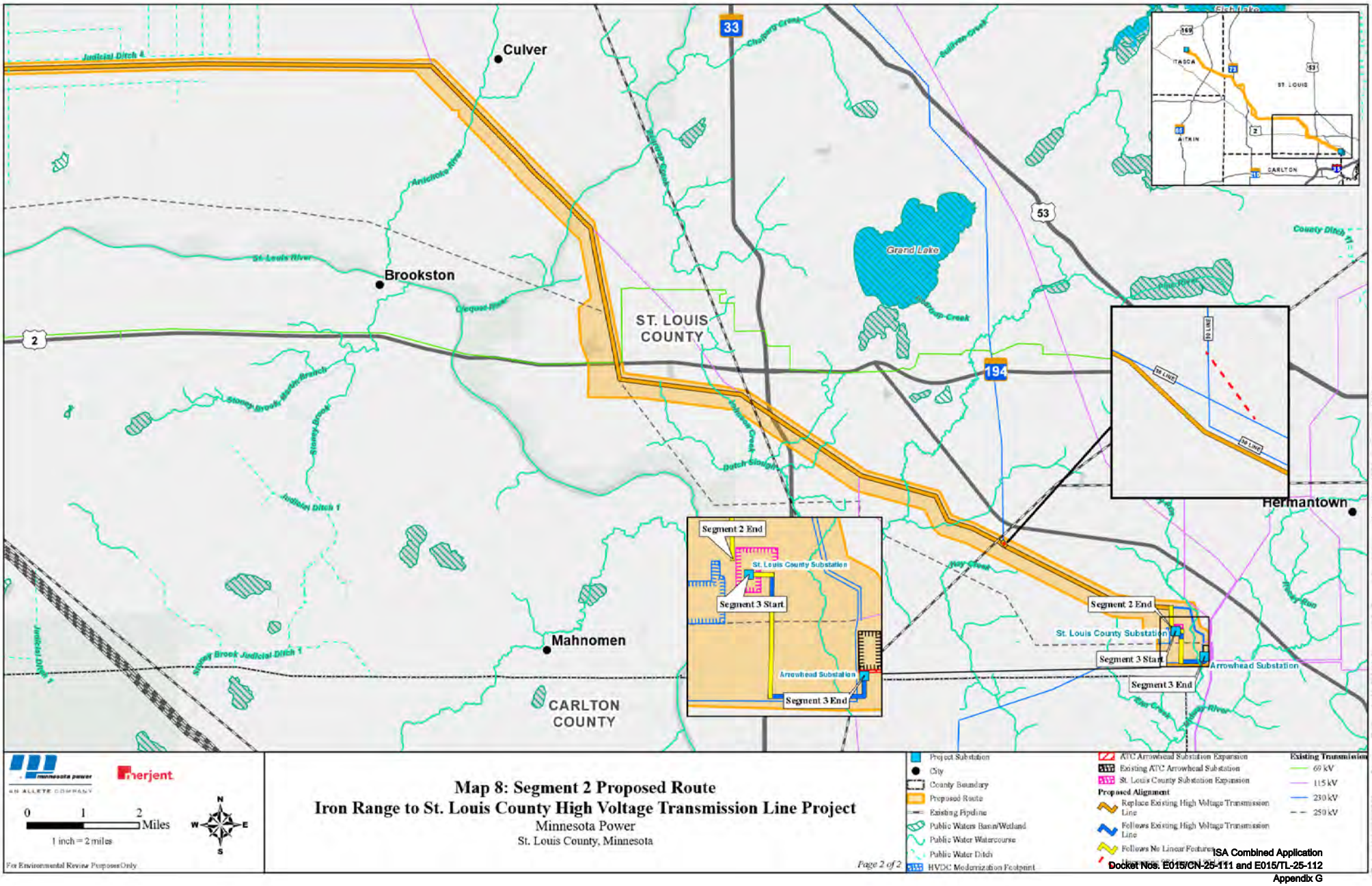
Minnesota Power
St. Louis County, Minnesota

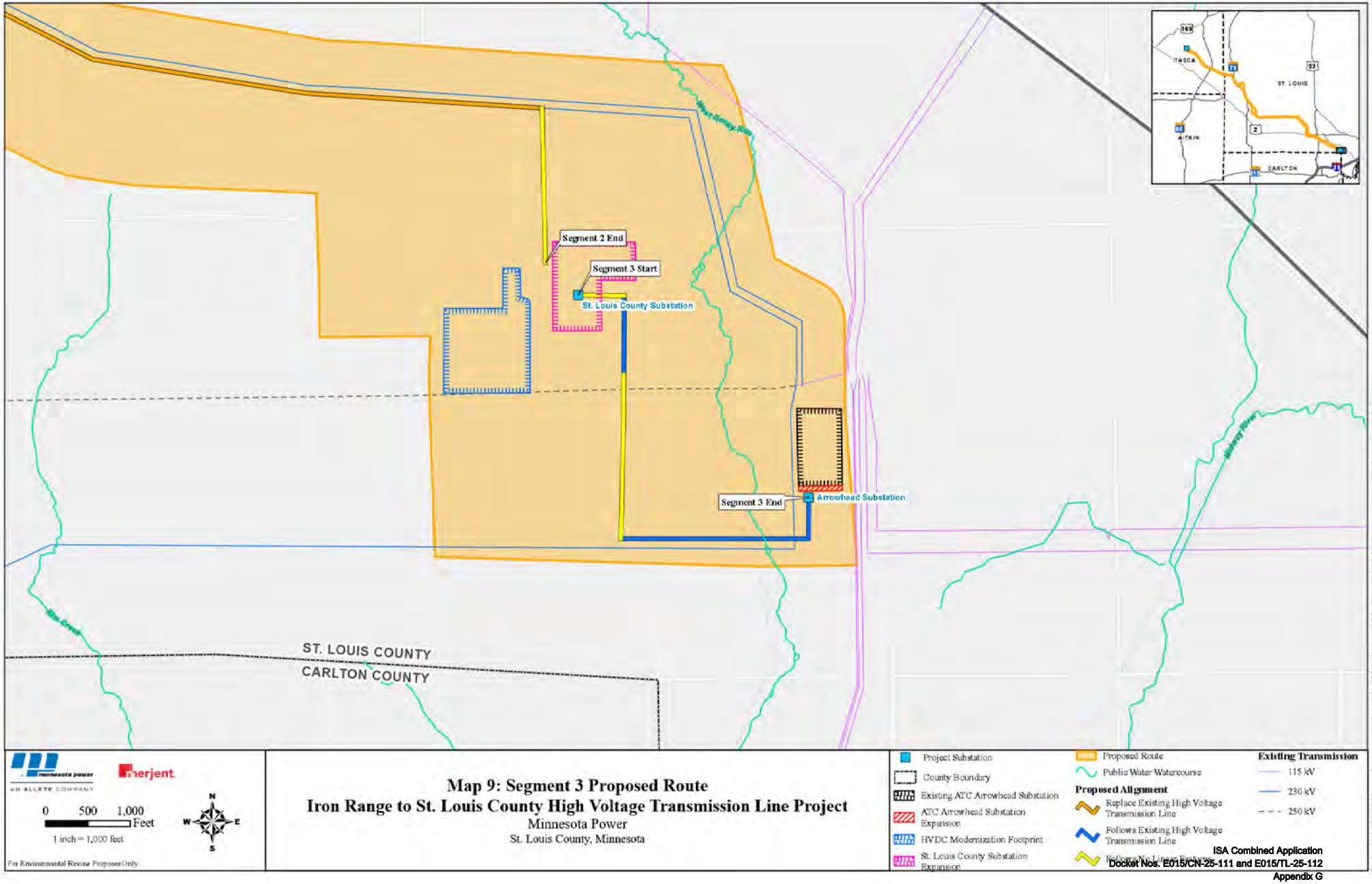
Page 1 of 2

- City
- County Boundary
- Proposed Route
- Existing Pipeline
- Public Waters Basin/Wetland
- Public Water Watercourse
- Public Water Ditch
- HVDC Modernization Footprint
- ATC Arrowhead Substation Expansion
- Existing ATC Arrowhead Substation
- St. Louis County Substation Expansion

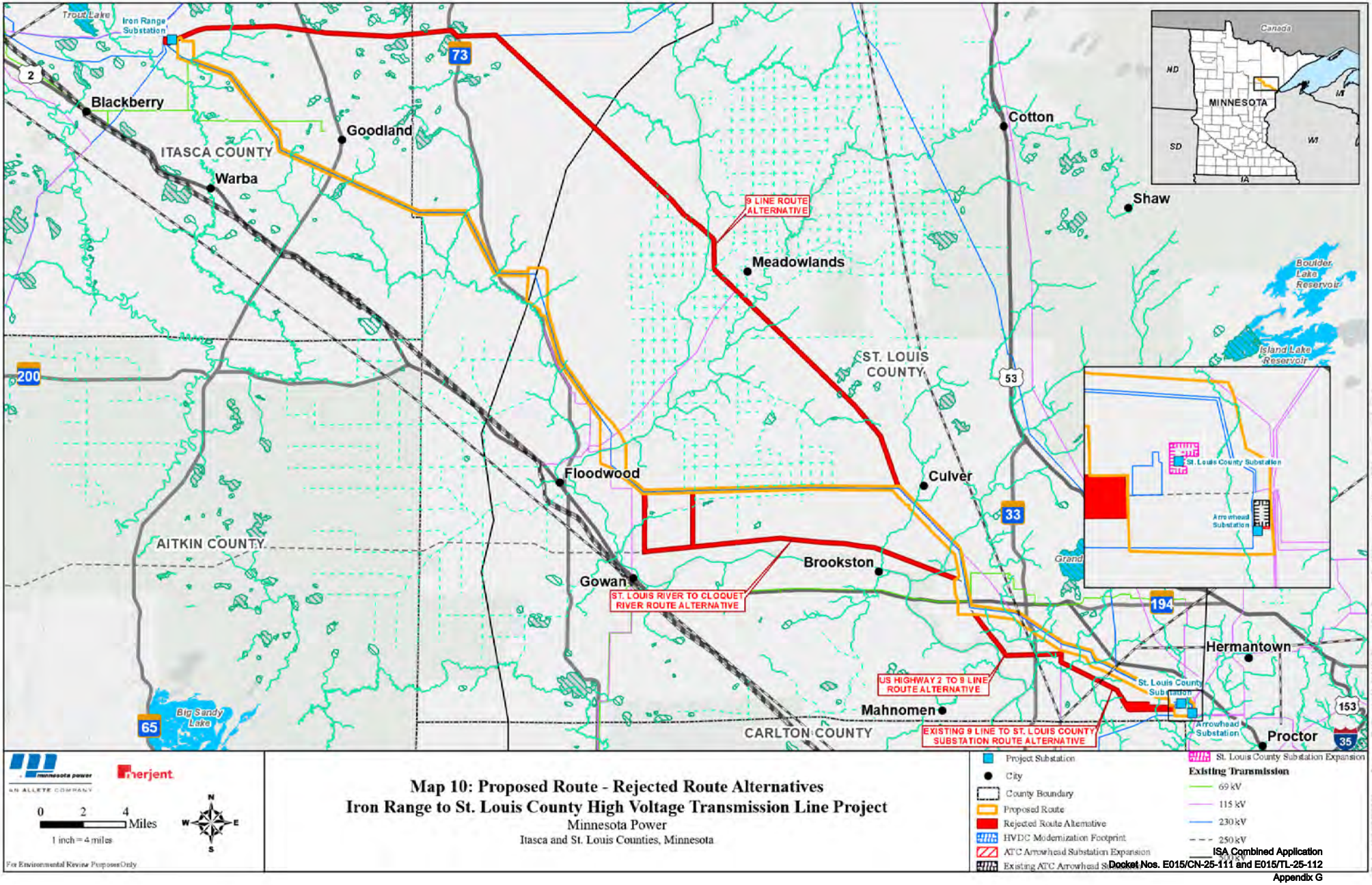
Proposed Alignment
- Replace Existing High Voltage Transmission Line
- Follows Existing High Voltage Transmission Line

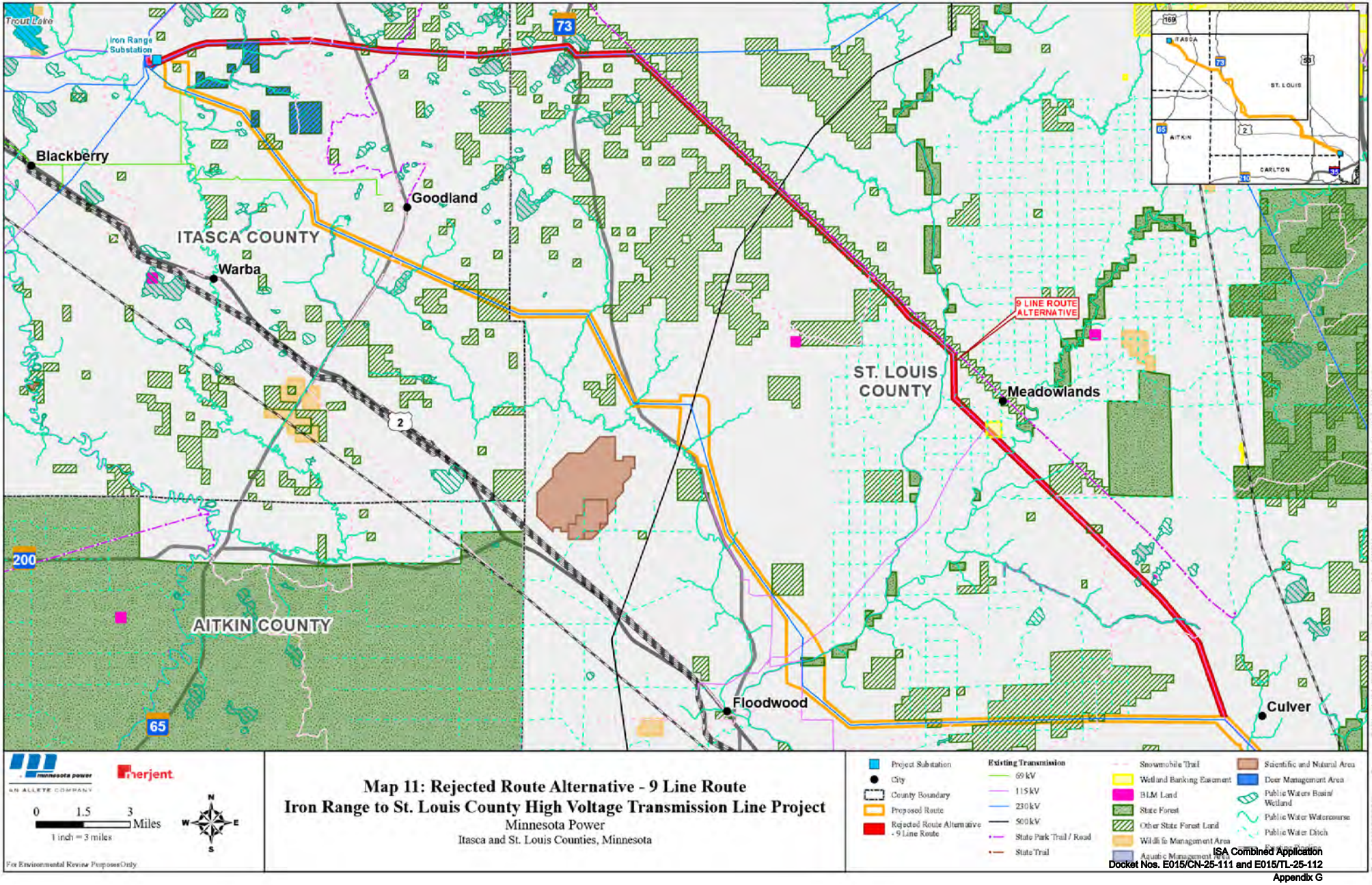
Existing Transmission
- 69 kV
- 115 kV
- 230 kV
- 250 kV


Culver
Brookston
Mahnomen
Hermantown
ST. LOUIS COUNTY
CARLTON COUNTY
Grand Lake
Segment 2 End
St. Louis County Substation
Segment 3 Start
Arrowhead Substation
Segment 3 End
Segment 2 End
St. Louis County Substation
Segment 3 Start
Arrowhead Substation
Segment 3 End
33
53
2
194
Judicial Ditch 4
Clearwater River
Sullivan Creek
Sullivan Creek
Anichoke River
St. Louis River
Clearwater River
County Ditch 11
Clearwater River
Stoney Brook Judicial Branch
Stoney Brook
Judicial Ditch 1
Johnson Creek
Dutch Slough
Hay Creek
Rice Lake
Stoney Brook Judicial Ditch 1
Judicial Ditch 1
Hay Creek
Tamarack River
Fish Lake
ITASCA
ST. LOUIS
AITKIN
CARLTON
50 LINE
50 LINE
50 LINE
minnesota power
AN ALLETE COMPANY
enerjent
0 1 2 Miles
1 inch = 2 miles
N
W
E
S
For Environmental Review Purposes Only
Map 8: Segment 2 Proposed Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
St. Louis County, Minnesota
Page 2 of 2
Project Substation
City
County Boundary
Proposed Route
Existing Pipeline
Public Waters Basin/Wetland
Public Water Watercourse
Public Water Ditch
HVDC Modernization Footprint
ATC Arrowhead Substation Expansion
Existing ATC Arrowhead Substation
St. Louis County Substation Expansion
Proposed Alignment
Replace Existing High Voltage Transmission Line
Follows Existing High Voltage Transmission Line
Follows No Linear Features
Existing Transmission
69 kV
115 kV
230 kV
250 kV

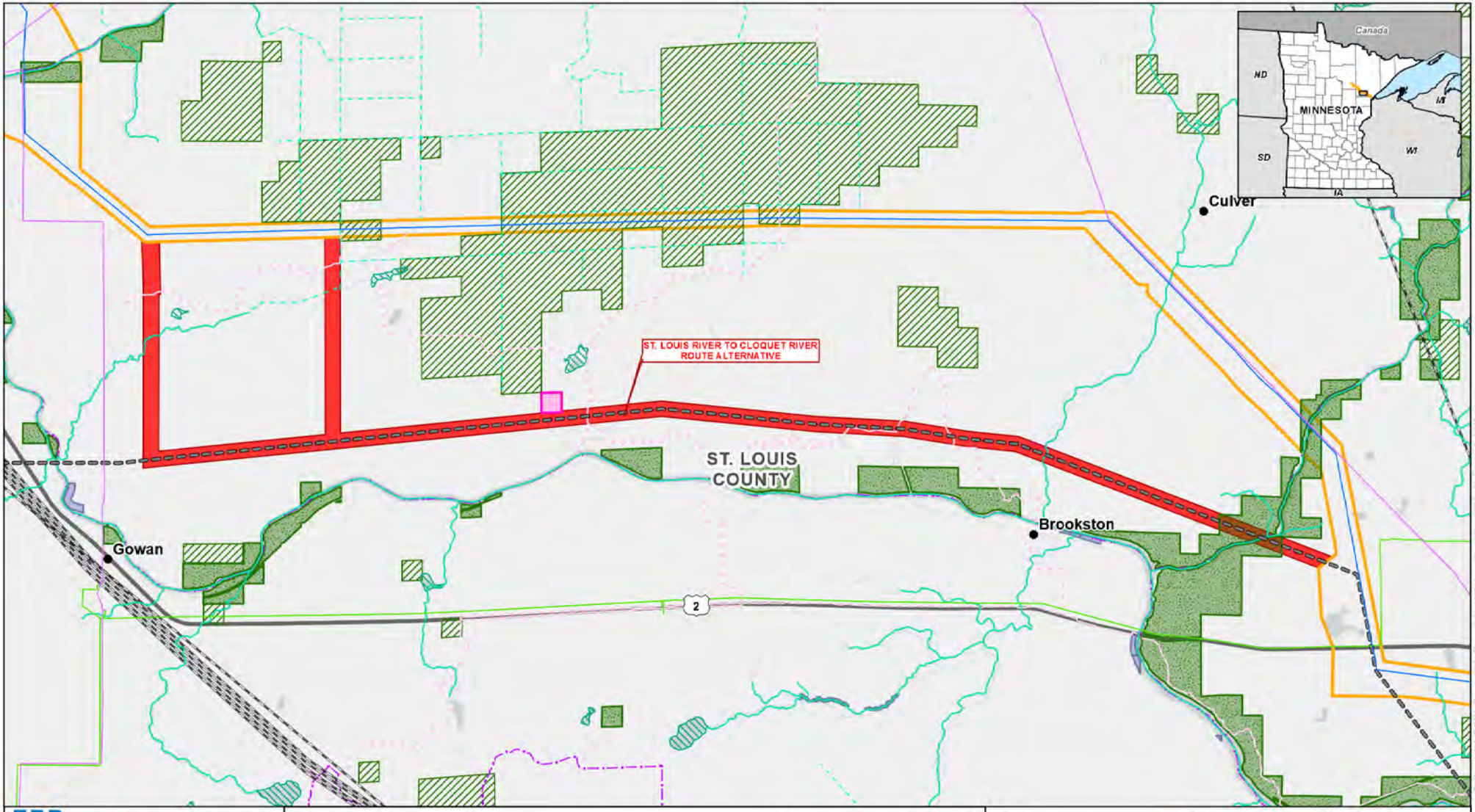


Map 9: Segment 3 Proposed Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
St. Louis County, Minnesota


Trout Lake
Iron Range Substation
Blackberry
Goodland
ITASCA COUNTY
Warba
73
2
9 LINE ROUTE ALTERNATIVE
Meadowlands
Cotton
Shaw
Canada
ND
MINNESOTA
SD
IA
WI
MI
Boulder Lake Reservoir
Island Lake Reservoir
ST. LOUIS COUNTY
53
200
Floodwood
Culver
33
St. Louis County Substation
Arrowhead Substation
AITKIN COUNTY
Brookston
Gowan
ST. LOUIS RIVER TO CLOQUET RIVER ROUTE ALTERNATIVE
194
Hermantown
US HIGHWAY 2 TO 9 LINE ROUTE ALTERNATIVE
Mahnomen
CARLTON COUNTY
EXISTING 9 LINE TO ST. LOUIS COUNTY SUBSTATION ROUTE ALTERNATIVE
Proctor
153
35
65
Big Sandy Lake
minnesota power
AN ALLETE COMPANY
enerjent
0 2 4 Miles
1 inch = 4 miles
N
W
E
S
For Environmental Review Purposes Only
Map 10: Proposed Route - Rejected Route Alternatives
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota
Project Substation
City
County Boundary
Proposed Route
Rejected Route Alternative
HVDC Modernization Footprint
ATC Arrowhead Substation Expansion
Existing ATC Arrowhead Substation
St. Louis County Substation Expansion
Existing Transmission
69 kV
115 kV
230 kV
250 kV
345 kV



Map 11: Rejected Route Alternative - 9 Line Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota



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merjent

0 0.5 1 Mile
1 inch = 1 mile

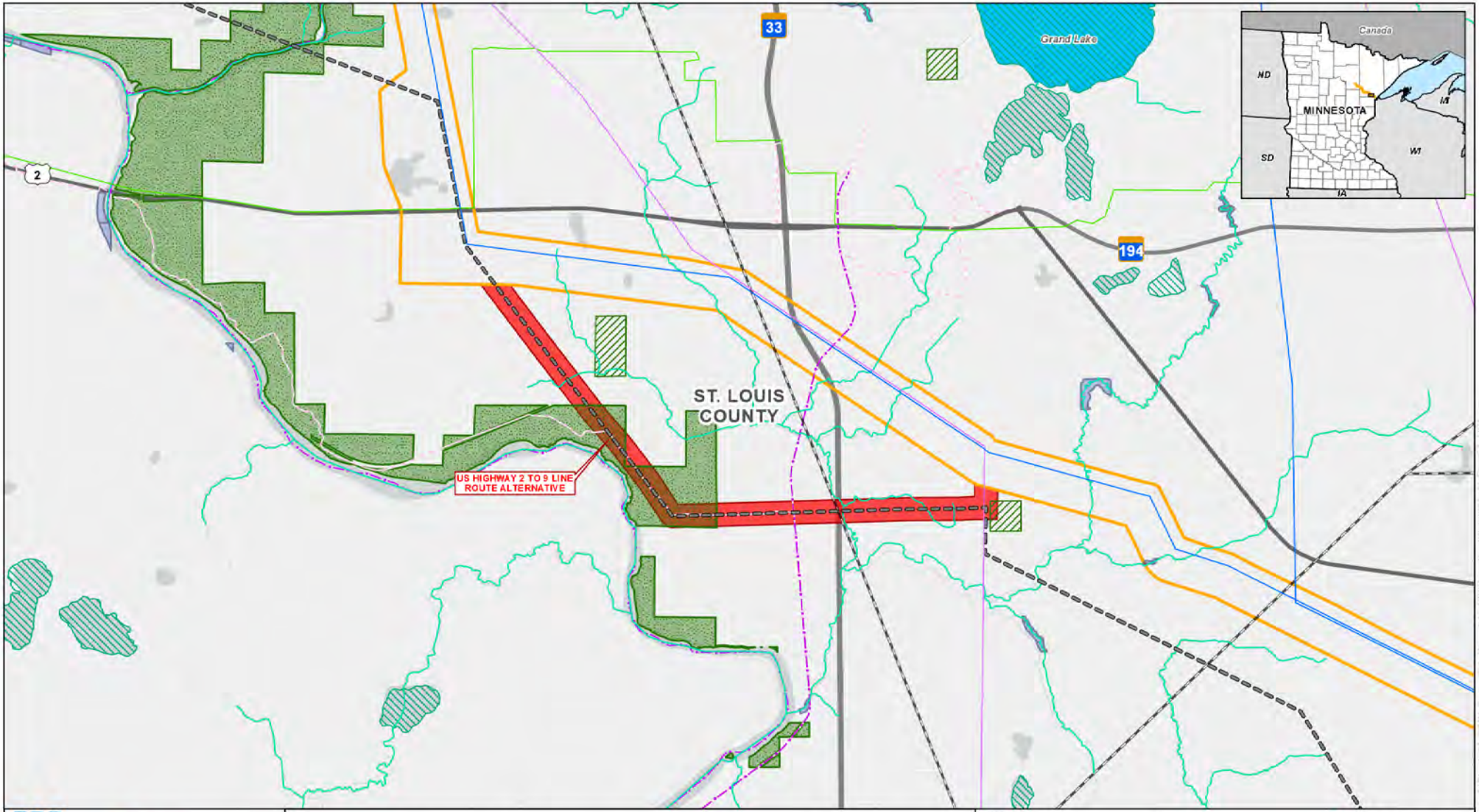
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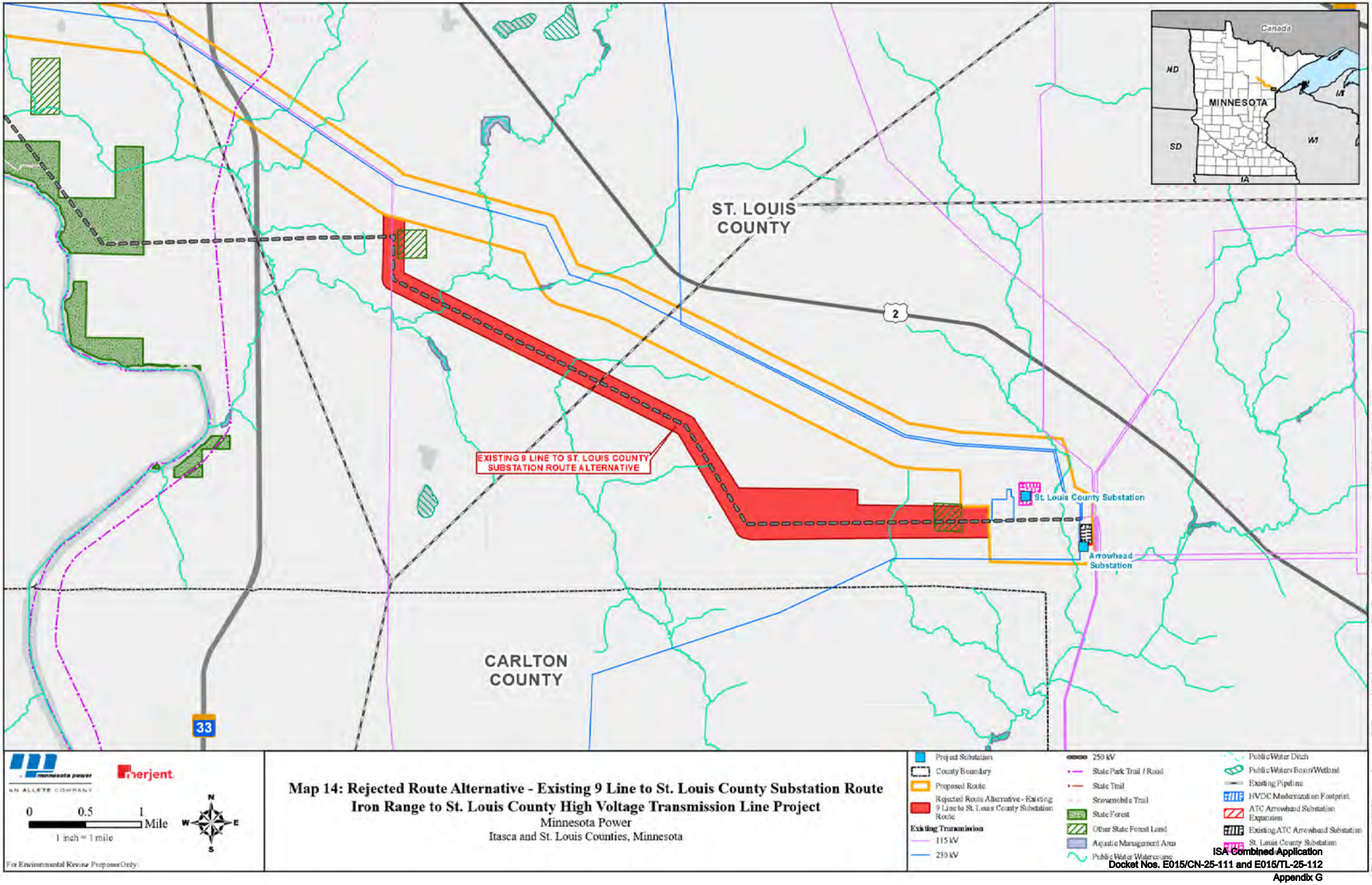
Map 12: Rejected Route Alternative - St. Louis River to Cloquet River Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota

- City
- County Boundary
- Proposed Route
- Rejected Route Alternative - St. Louis River to Cloquet River Route

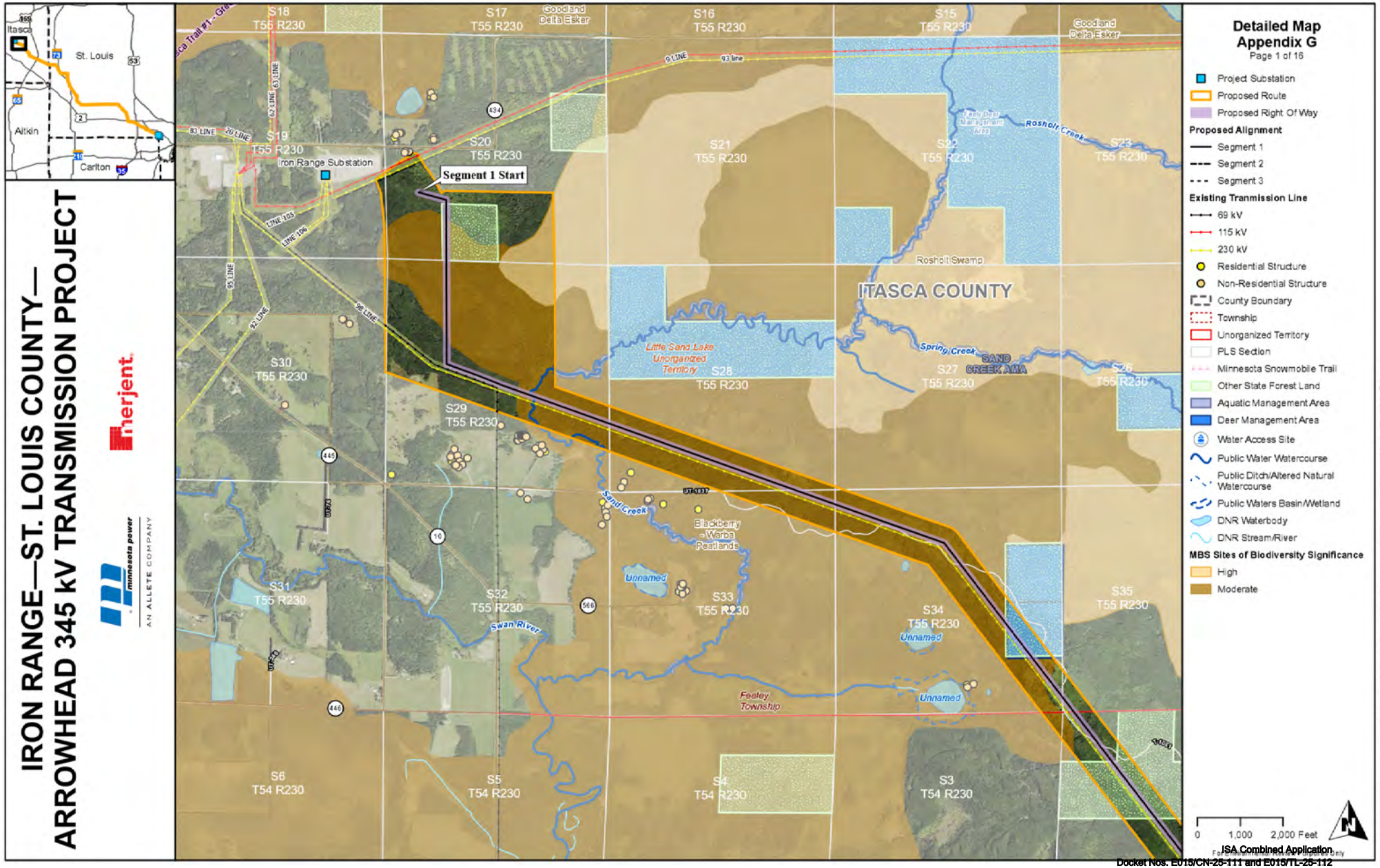
Existing Transmission
- 69 kV
- 115 kV
- 230 kV
- 250 kV
- State Park Trail / Road
- Snowmobile Trail
- State Forest
- Other State Forest Land
- Aquatic Management Area
- BLM Land
- Public Water Watercourse
- Public Water Ditch
- Public Waters Basin/Wetland
- Existing Pipeline

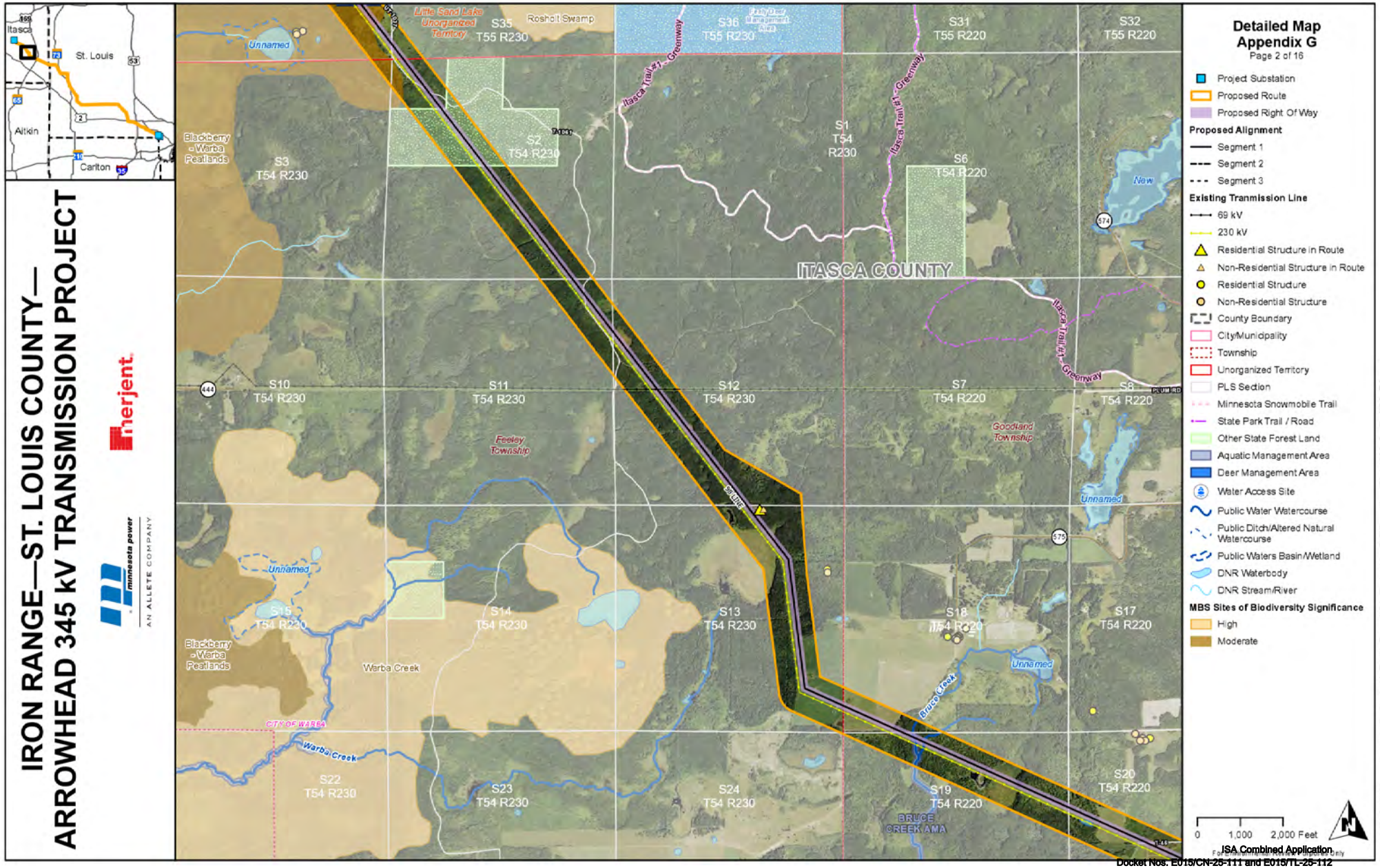


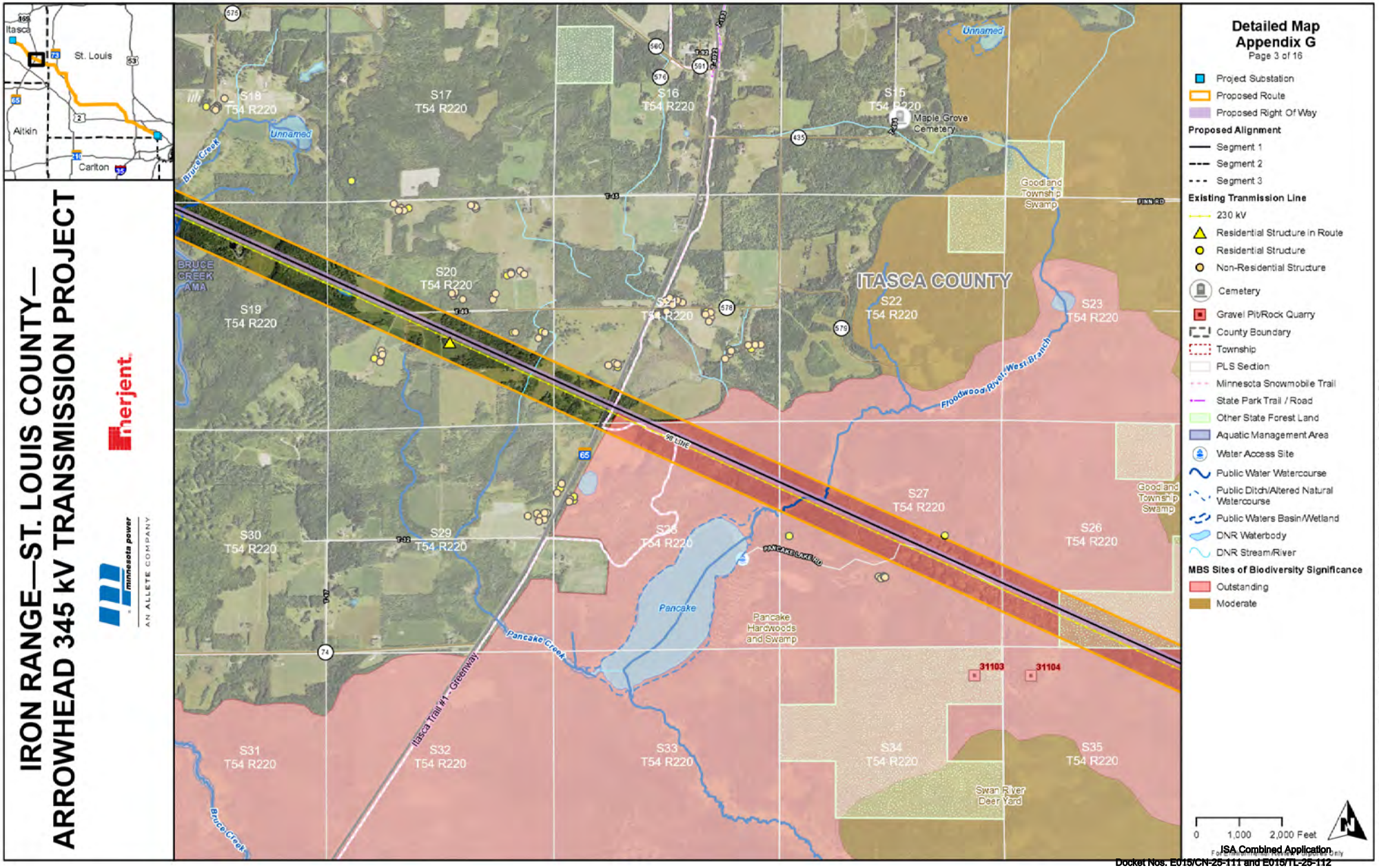
Map 13: Rejected Route Alternative - US Highway 2 to 9 Line Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota

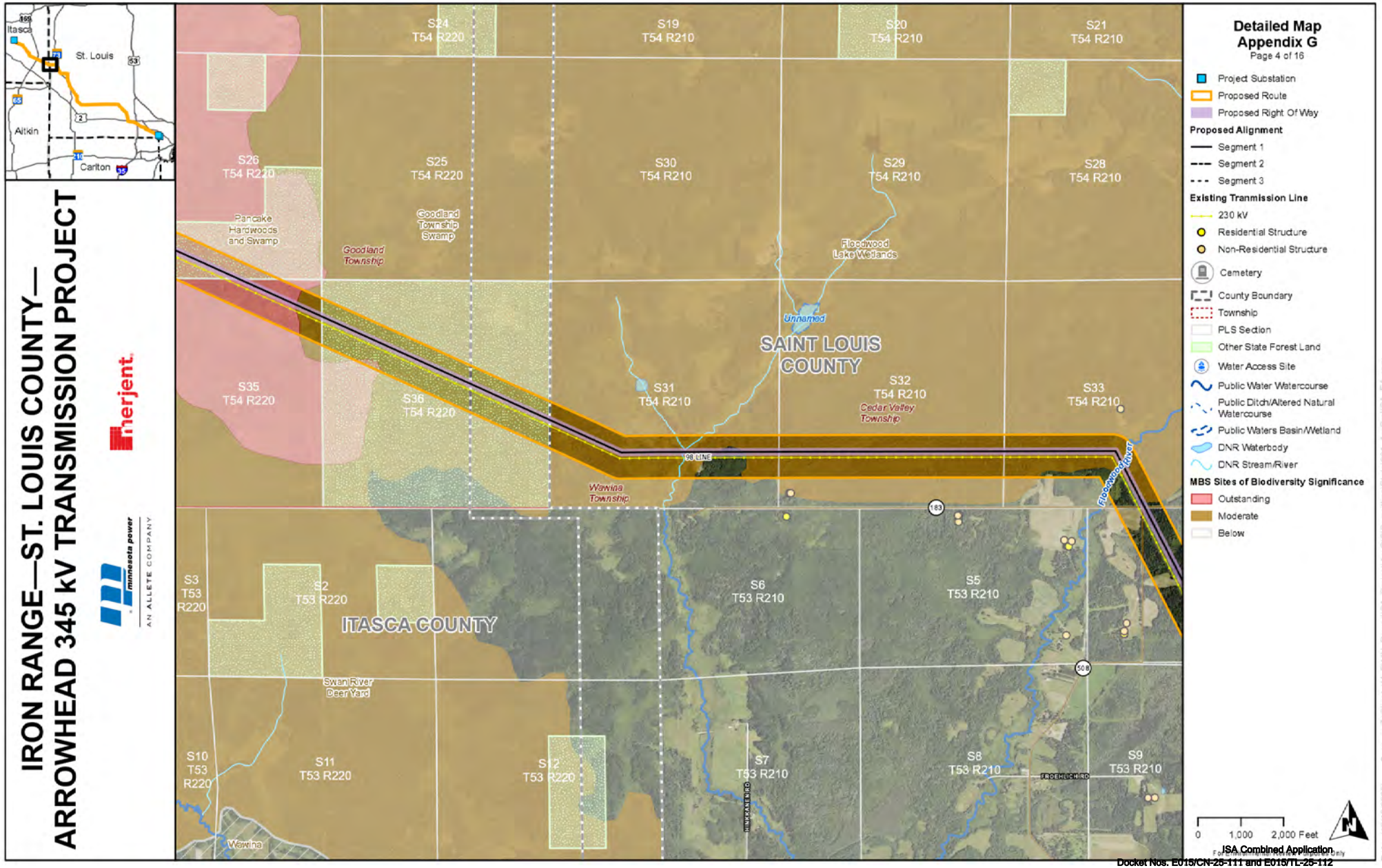


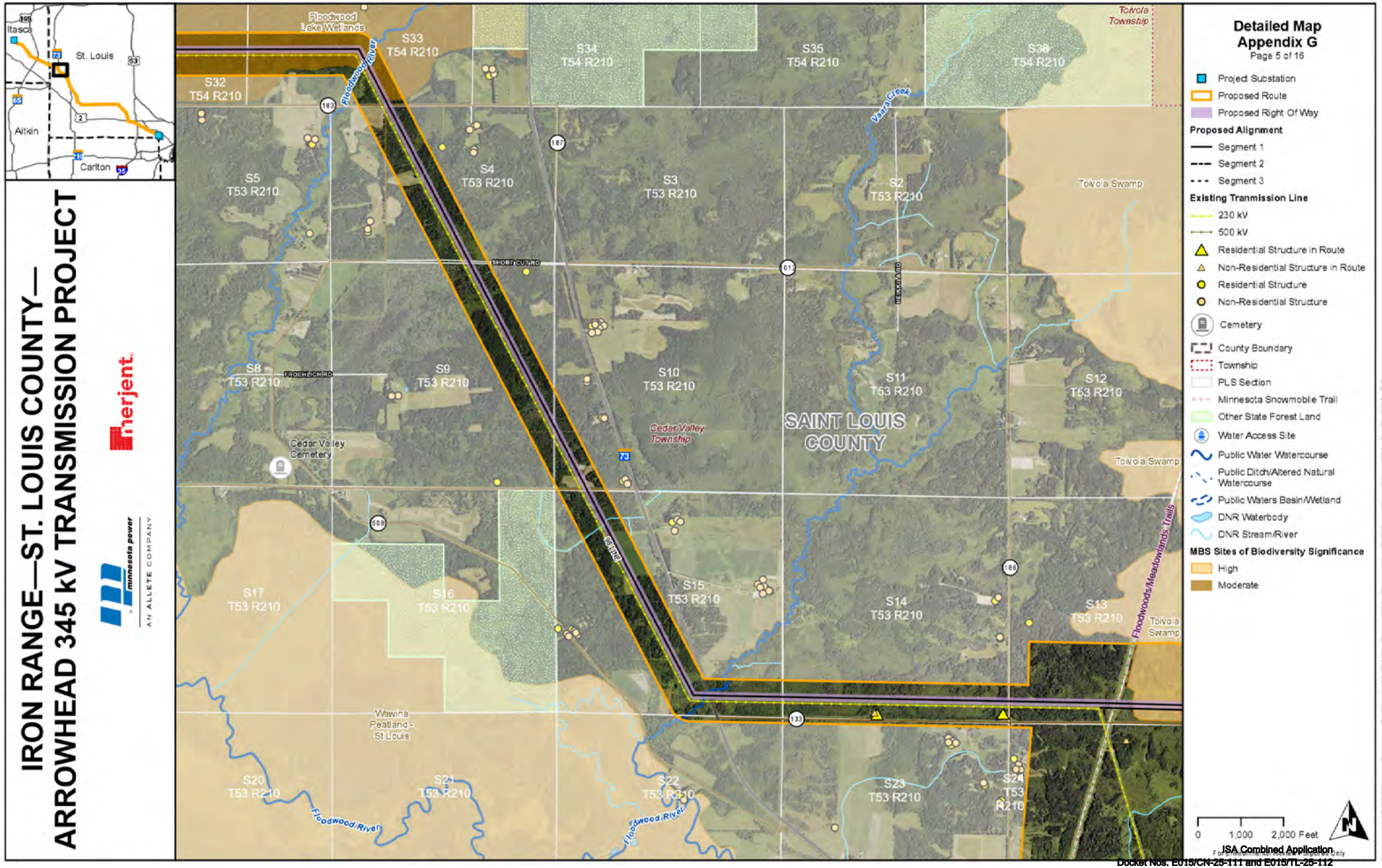
Map 14: Rejected Route Alternative - Existing 9 Line to St. Louis County Substation Route
Iron Range to St. Louis County High Voltage Transmission Line Project
Minnesota Power
Itasca and St. Louis Counties, Minnesota

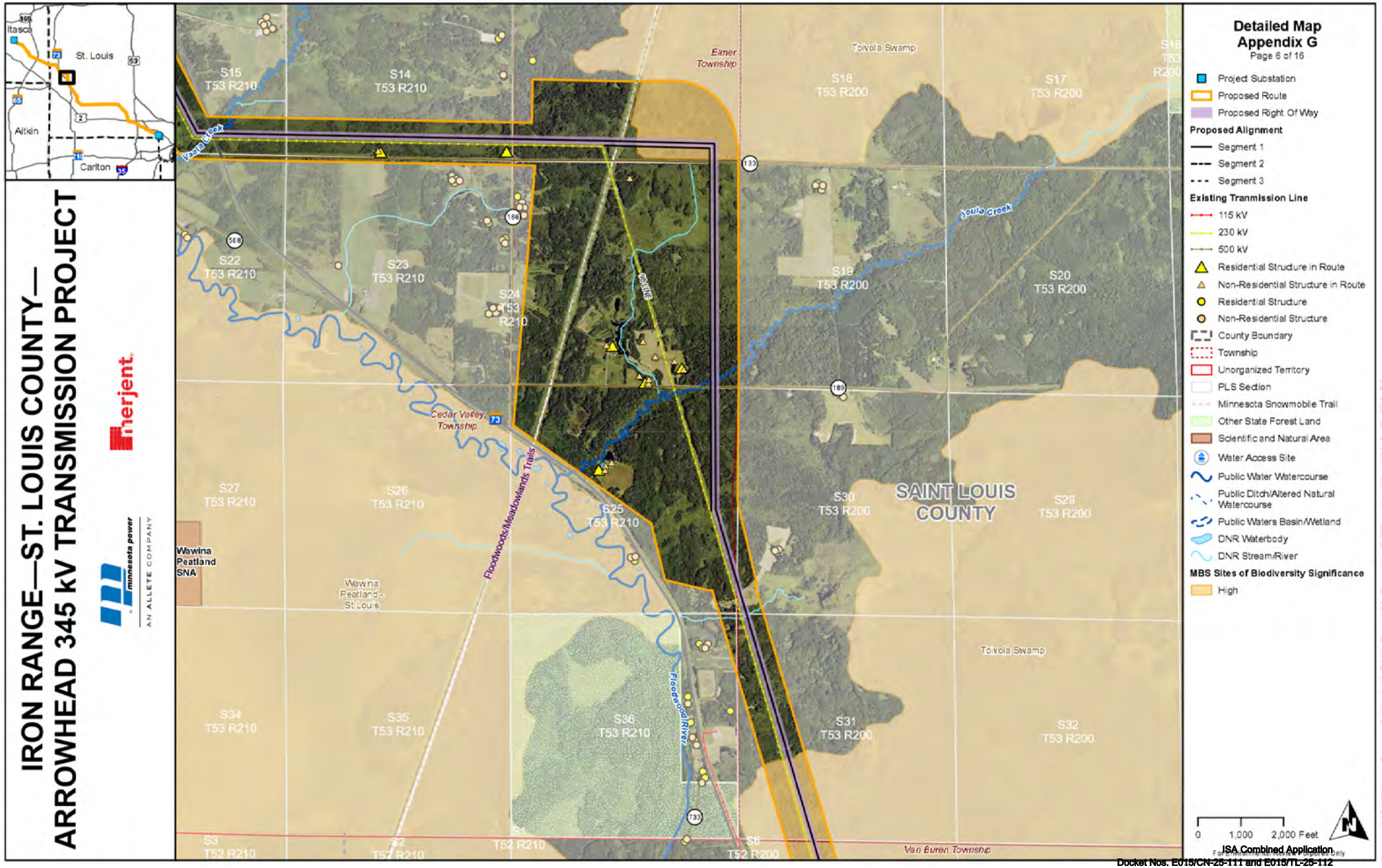

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 1 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
69 kV
115 kV
230 kV
Residential Structure
Non-Residential Structure
County Boundary
Township
Unorganized Territory
PLS Section
Minnesota Snowmobile Trail
Other State Forest Land
Aquatic Management Area
Deer Management Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
Moderate
Segment 1 Start
Iron Range Substation
ITASCA COUNTY
Rosholt Swamp
Little Sand Lake Unorganized Territory
SAND CREEK AMA
Blackberry - Warba Peatlands
Feeley Township
Unnamed
Spring Creek
Sand Creek
Swan River
Rosholt Creek
Goodland Delta Esker
S18 T55 R230
S17 T55 R230
S16 T55 R230
S15 T55 R230
S19 T55 R230
S20 T55 R230
S21 T55 R230
S22 T55 R230
S23 T55 R230
S30 T55 R230
S29 T55 R230
S28 T55 R230
S27 T55 R230
S25 T55 R230
S31 T55 R230
S32 T55 R230
S33 T55 R230
S34 T55 R230
S35 T55 R230
S6 T54 R230
S5 T54 R230
S4 T54 R230
S3 T54 R230
St. Louis
Aitkin
Carlton
Itasca
0 1,000 2,000 Feet
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Date: (12/18/2025)


IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 2 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
69 kV
230 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
County Boundary
City/Municipality
Township
Unorganized Territory
PLS Section
Minnesota Snowmobile Trail
State Park Trail / Road
Other State Forest Land
Aquatic Management Area
Deer Management Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
Moderate
ITASCA COUNTY
Little Sand Lake Unorganized Territory
Rosholt Swamp
Itasca Trail #1 - Greenway
Blackberry - Warba Peatlands
Feeley Township
Goodland Township
Warba Creek
Bruce Creek
CITY OF WARBA
BRUCE CREEK AMA
Unnamed
S1 T54 R230
S2 T54 R230
S3 T54 R230
S6 T54 R220
S7 T54 R220
S8 T54 R220
S10 T54 R230
S11 T54 R230
S12 T54 R230
S13 T54 R230
S14 T54 R230
S15 T54 R220
S17 T54 R220
S18 T54 R220
S19 T54 R220
S20 T54 R220
S22 T54 R230
S23 T54 R230
S24 T54 R230
S31 T55 R220
S32 T55 R220
S35 T55 R230
S36 T55 R230
Itasca
St. Louis
Aitkin
Carlton
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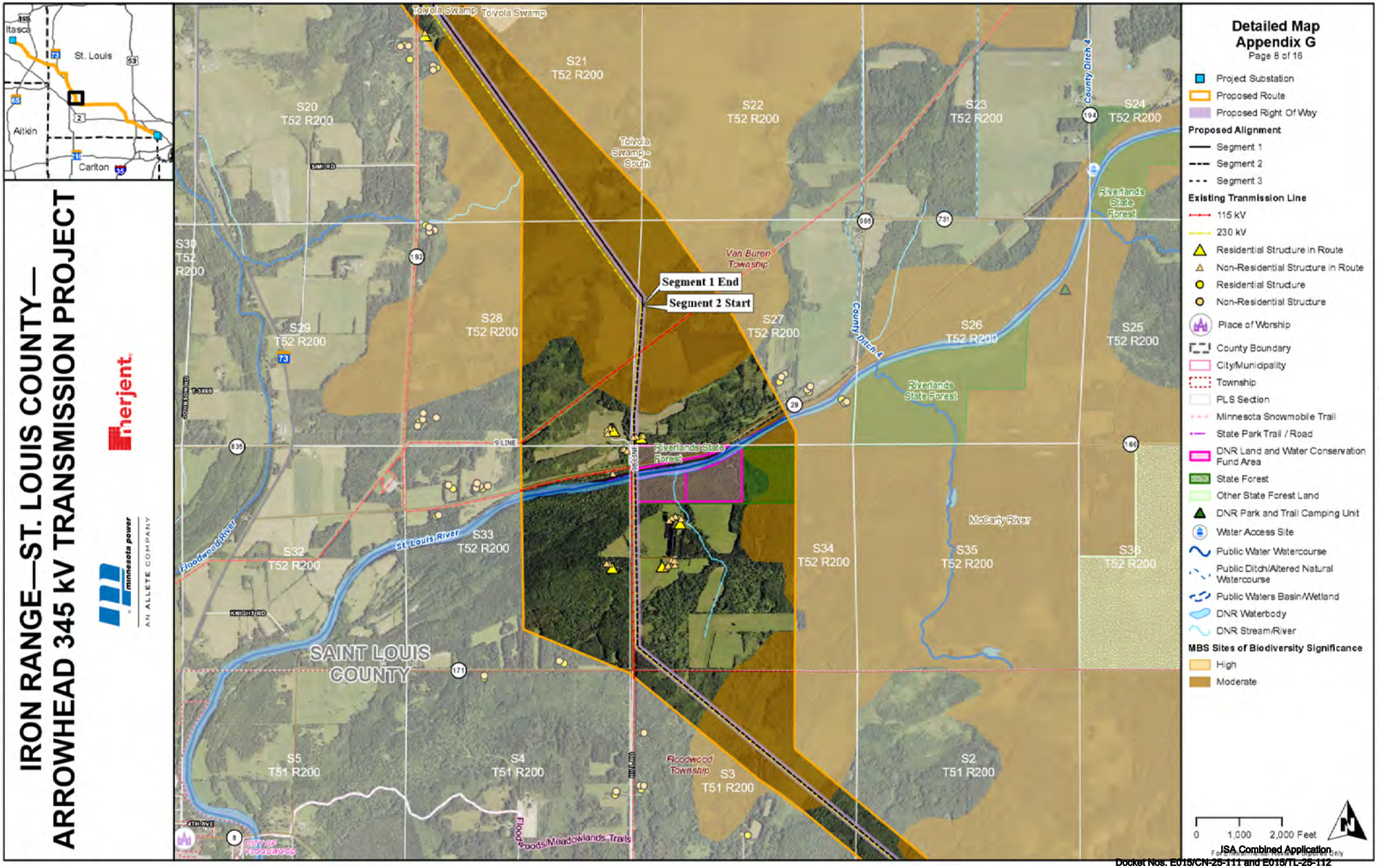

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 3 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
230 kV
Residential Structure in Route
Residential Structure
Non-Residential Structure
Cemetery
Gravel Pit/Rock Quarry
County Boundary
Township
PLS Section
Minnesota Snowmobile Trail
State Park Trail / Road
Other State Forest Land
Aquatic Management Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
Outstanding
Moderate
ITASCA COUNTY
S17 T54 R220
S16 T54 R220
S15 T54 R220
S18 T54 R220
S19 T54 R220
S20 T54 R220
S21 T54 R220
S22 T54 R220
S23 T54 R220
S27 T54 R220
S26 T54 R220
S30 T54 R220
S29 T54 R220
S28 T54 R220
S31 T54 R220
S32 T54 R220
S33 T54 R220
S34 T54 R220
S35 T54 R220
Maple Grove Cemetery
Goodland Township Swamp
Floodwood River, West Branch
Pancake
Pancake Hardwoods and Swamp
Pancake Creek
Bruce Creek
Unnamed
Itasca Trail #1 - Greenway
Swan River Deer Yard
BRUCE CREEK AMA
98 LINE
PANCAKE LAKE RD
FINN RD
31103
31104
0 1,000 2,000 Feet
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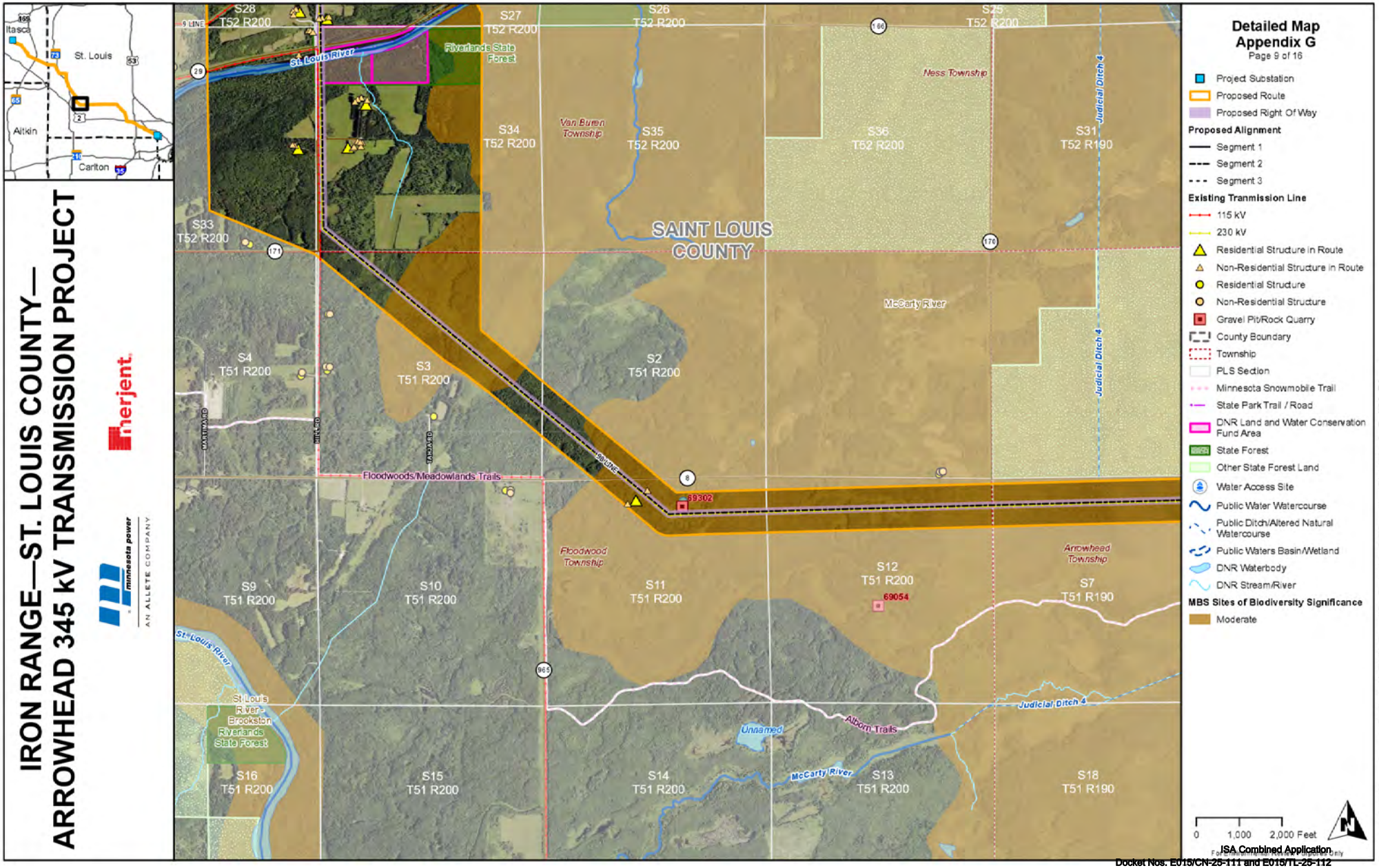

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Itasca
St. Louis
Aitkin
Carlton
S24 T54 R220
S19 T54 R210
S20 T54 R210
S21 T54 R210
S26 T54 R220
S25 T54 R220
S30 T54 R210
S29 T54 R210
S28 T54 R210
Pancake Hardwoods and Swamp
Goodland Township Swamp
Goodland Township
Floodwood Lake Wetlands
Unnamed
SAINT LOUIS COUNTY
S35 T54 R220
S36 T54 R220
S31 T54 R210
S32 T54 R210
Cedar Valley Township
S33 T54 R210
98 LINE
Wawina Township
Floodwood River
S3 T53 R220
S2 T53 R220
ITASCA COUNTY
S6 T53 R210
S5 T53 R210
Swan River Deer Yard
S10 T53 R220
S11 T53 R220
S12 T53 R220
S7 T53 R210
S8 T53 R210
S9 T53 R210
HINKKANEN RD
FROEHLICH RD
Wawina
Detailed Map
Appendix G
Page 4 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
230 kV
Residential Structure
Non-Residential Structure
Cemetery
County Boundary
Township
PLS Section
Other State Forest Land
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
Outstanding
Moderate
Below
0
1,000
2,000 Feet
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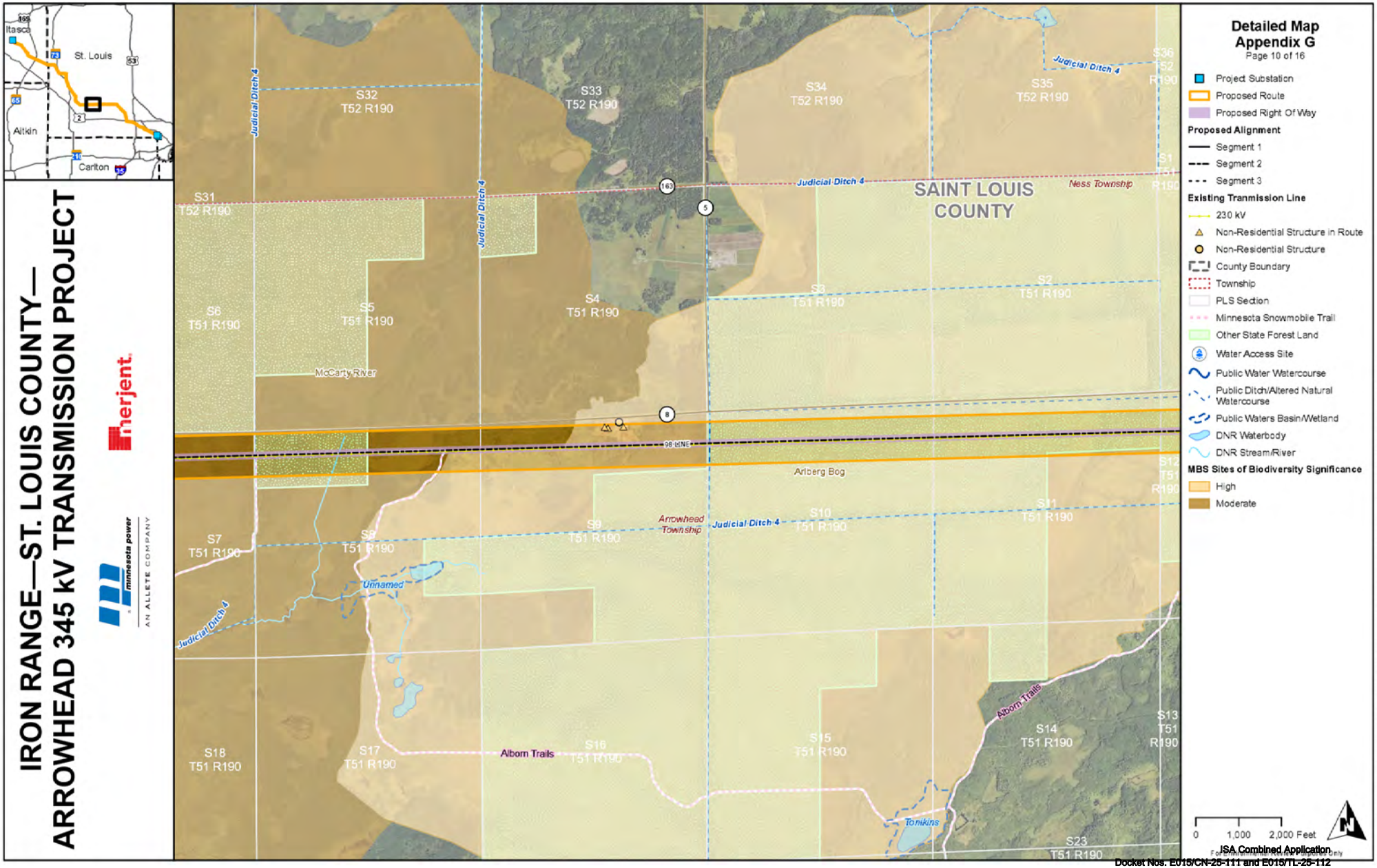

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 5 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
230 kV
500 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Cemetery
County Boundary
Township
PLS Section
Minnesota Snowmobile Trail
Other State Forest Land
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
Moderate
SAINT LOUIS COUNTY
Floodwood Lake Wetlands
Floodwood River
Tolvola Township
Tolvola Swamp
Cedar Valley Township
Cedar Valley Cemetery
Wawina Peatland - St Louis
Floodwoods/Meadowlands Trails
Vera Creek
SHORT CUT RD
FROEMSCH RD
HEKKILA RD
S32 T54 R210
S33 T54 R210
S34 T54 R210
S35 T54 R210
S36 T54 R210
S5 T53 R210
S4 T53 R210
S3 T53 R210
S2 T53 R210
S8 T53 R210
S9 T53 R210
S10 T53 R210
S11 T53 R210
S12 T53 R210
S17 T53 R210
S16 T53 R210
S15 T53 R210
S14 T53 R210
S13 T53 R210
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S22 T53 R210
S23 T53 R210
S24 T53 R210
0 1,000 2,000 Feet
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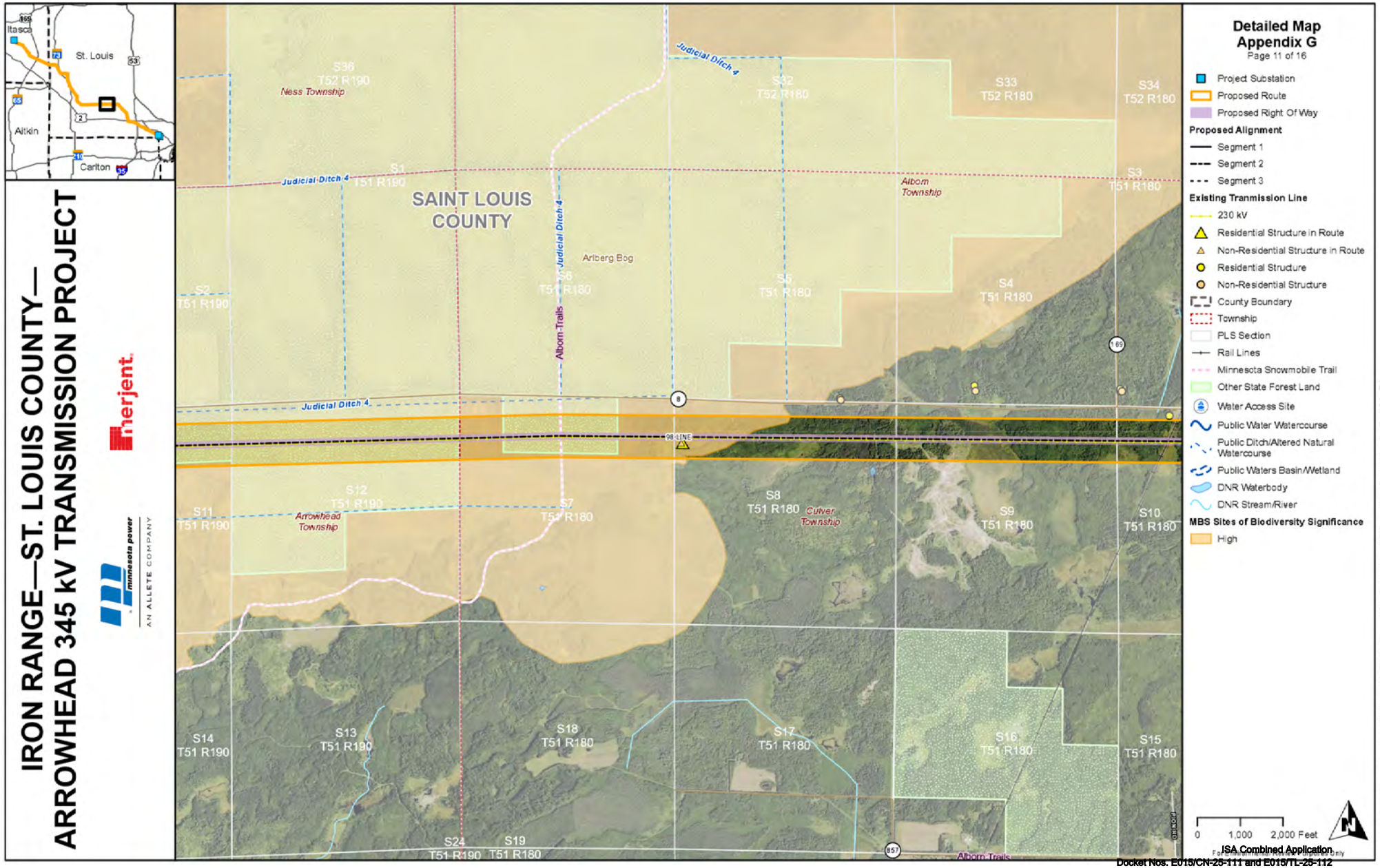

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 6 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
115 kV
230 kV
500 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
County Boundary
Township
Unorganized Territory
PLS Section
Minnesota Snowmobile Trail
Other State Forest Land
Scientific and Natural Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
SAINT LOUIS COUNTY
Elmer Township
Tolvola Swamp
Cedar Valley Township
Van Buren Township
Floodwoods/Meadowlands Trails
Floodwood River
Joula Creek
Wawina Peatland SNA
Wawina Peatland - St Louis
S15 T53 R210
S14 T53 R210
S18 T53 R200
S17 T53 R200
S22 T53 R210
S23 T53 R210
S24 T53 R210
S19 T53 R200
S20 T53 R200
S27 T53 R210
S26 T53 R210
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ISA Combined Application
Docket Nos. E015/CN-25-111 and E015/TL-25-112
Appendix G
Page 24 of 34

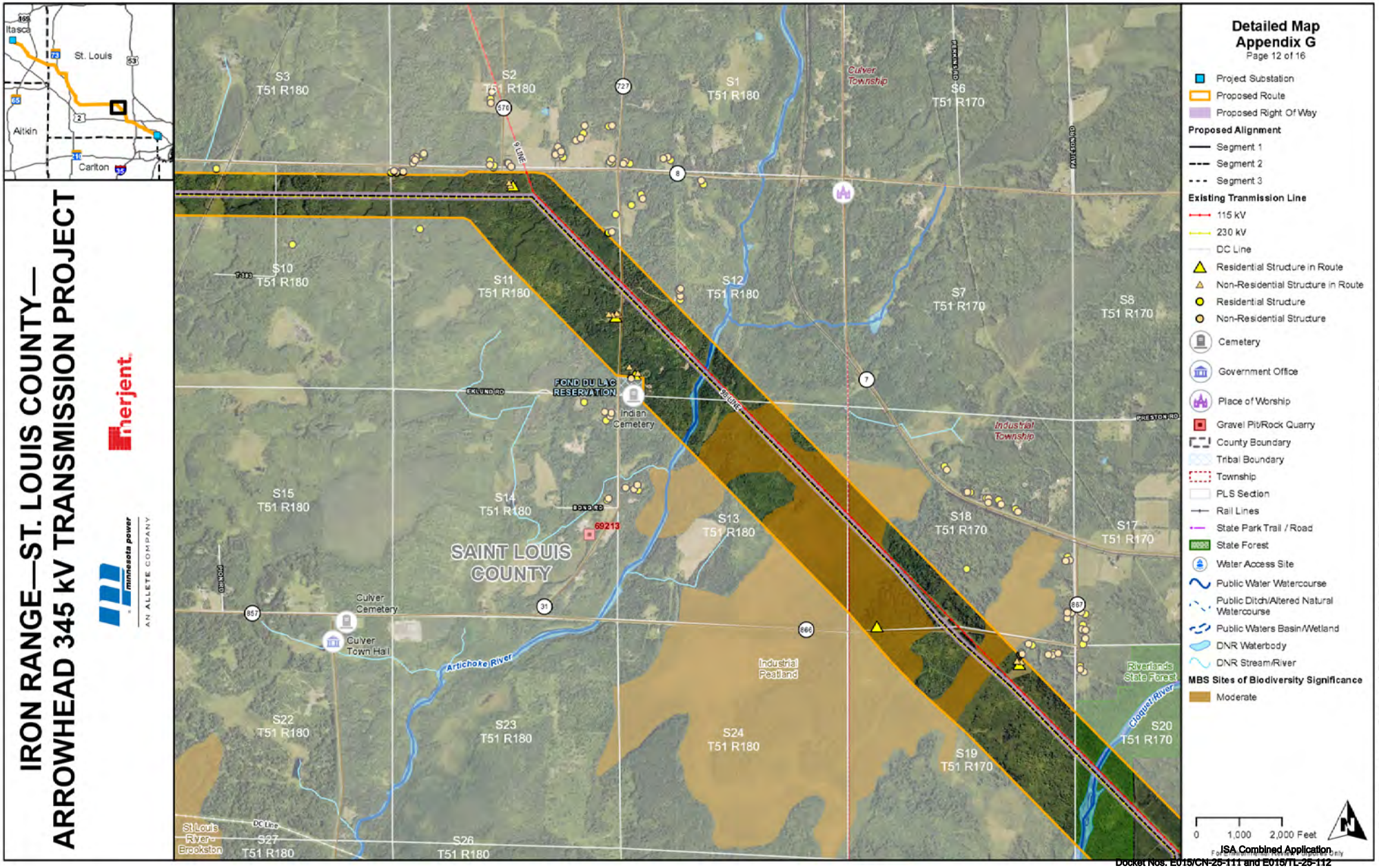

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
minnesota power
AN ALLETE COMPANY
Detailed Map
Appendix G
Page 7 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
115 kV
230 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Cemetery
Government Office
Gravel Pit/Rock Quarry
County Boundary
Township
Unorganized Territory
PLS Section
Other State Forest Land
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
Moderate
SAINT LOUIS COUNTY
Cedar Valley Township
Elmer Township
Van Buren Township
Potsho Lake Unorganized Territory
Tolvola Swamp
Tolvola Swamp - South
Wawina Peatland - St Louis
Judicial Ditch 3
Floodwood River
Van Buren Township Hall
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TABLES RD
AUTIO RD
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St. Louis
Aitkin
Carlton

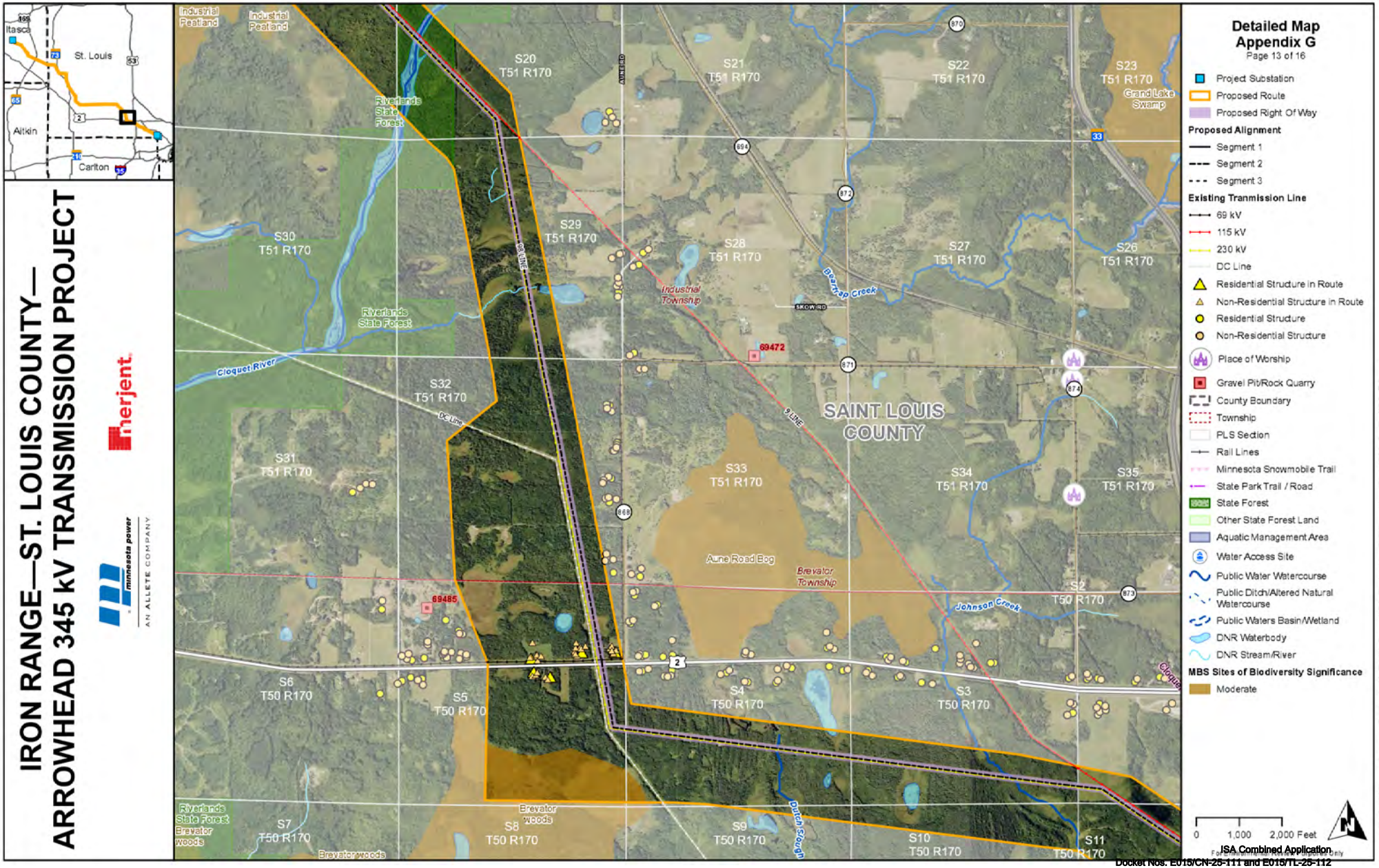

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 8 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
115 kV
230 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Place of Worship
County Boundary
City/Municipality
Township
PLS Section
Minnesota Snowmobile Trail
State Park Trail / Road
DNR Land and Water Conservation Fund Area
State Forest
Other State Forest Land
DNR Park and Trail Camping Unit
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
Moderate
Segment 1 End
Segment 2 Start
Toivola Swamp
Toivola Swamp - South
Van Buren Township
Floodwood Township
Riverlands State Forest
McCarty River
St. Louis River
Floodwood River
County Ditch 4
SAINT LOUIS COUNTY
CITY OF FLOODWOOD
Floodwoods Meadowlands Trails
S20 T52 R200
S21 T52 R200
S22 T52 R200
S23 T52 R200
S24 T52 R200
S25 T52 R200
S26 T52 R200
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S28 T52 R200
S29 T52 R200
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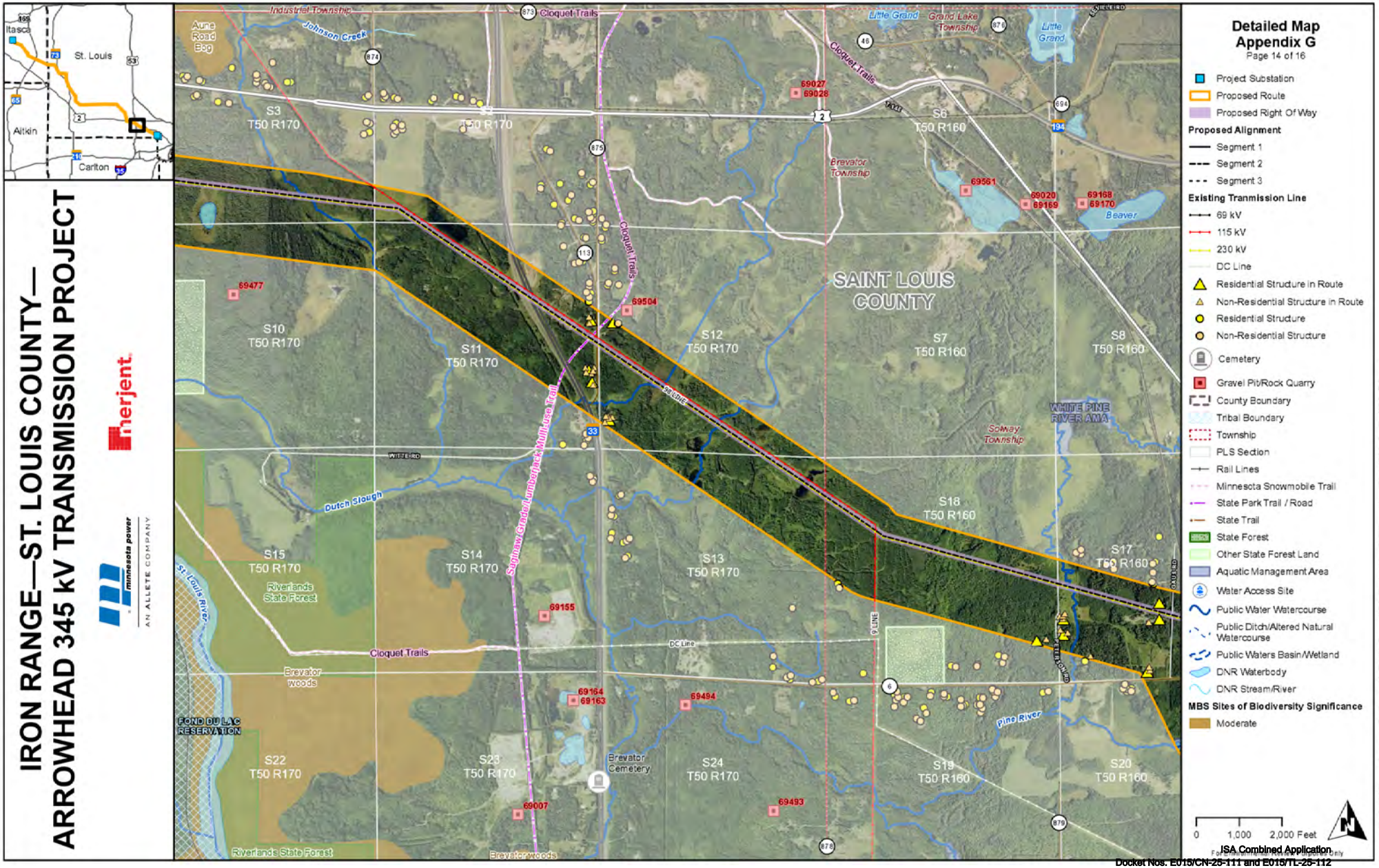

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 9 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
115 kV
230 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Gravel Pit/Rock Quarry
County Boundary
Township
PLS Section
Minnesota Snowmobile Trail
State Park Trail / Road
DNR Land and Water Conservation Fund Area
State Forest
Other State Forest Land
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
Moderate
SAINT LOUIS COUNTY
Riverlands State Forest
St. Louis River
Ness Township
Van Buren Township
Floodwood Township
Arrowhead Township
McCarty River
Judicial Ditch 4
Floodwoods/Meadowlands Trails
Alborn Trails
Unnamed
St. Louis River - Brookston Riverlands State Forest
69302
69054
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St. Louis
Aitkin
Carlton
minnesota power
AN ALLETE COMPANY
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IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Itasca
St. Louis
Aitkin
Carlton
Detailed Map
Appendix G
Page 10 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
230 kV
Non-Residential Structure in Route
Non-Residential Structure
County Boundary
Township
PLS Section
Minnesota Snowmobile Trail
Other State Forest Land
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
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Moderate
SAINT LOUIS COUNTY
Ness Township
Arrowhead Township
Judicial Ditch 4
McCarty River
Arlberg Bog
Unnamed
Alborn Trails
Tonikins
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S31 T52 R190
S32 T52 R190
S33 T52 R190
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S35 T52 R190
S36 T52 R190
S1 T51 R190
S2 T51 R190
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IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 11 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
230 kV
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
County Boundary
Township
PLS Section
Rail Lines
Minnesota Snowmobile Trail
Other State Forest Land
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
High
SAINT LOUIS COUNTY
Ness Township
Arrowhead Township
Culver Township
Alborn Township
Arlberg Bog
Judicial Ditch 4
Alborn Trails
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St. Louis
Aitkin
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Date: (12/18/2025)
ISA Combined Application
Docket Nos. E015/CN-25-111 and E015/TL-25-112
Appendix G
Page 29 of 34


IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Itasca
St. Louis
Aitkin
Carlton
S3 T51 R180
S2 T51 R180
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S18 T51 R170
S17 T51 R170
S22 T51 R180
S23 T51 R180
S24 T51 R180
S19 T51 R170
S20 T51 R170
S27 T51 R180
S26 T51 R180
SAINT LOUIS COUNTY
FOND DU LAC RESERVATION
Indian Cemetery
Culver Township
Industrial Township
Culver Cemetery
Culver Town Hall
Artichoke River
Industrial Peatland
Riverlands State Forest
Cloquet River
St Louis River-Brookston
DC Line
9 LINE
EKLUND RD
BOND RD
PRESTON RD
PERKINS RD
PAULSON RD
PONTO RD
69213
Detailed Map
Appendix G
Page 12 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
115 kV
230 kV
DC Line
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Cemetery
Government Office
Place of Worship
Gravel Pit/Rock Quarry
County Boundary
Tribal Boundary
Township
PLS Section
Rail Lines
State Park Trail / Road
State Forest
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
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IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 13 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
69 kV
115 kV
230 kV
DC Line
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Place of Worship
Gravel Pit/Rock Quarry
County Boundary
Township
PLS Section
Rail Lines
Minnesota Snowmobile Trail
State Park Trail / Road
State Forest
Other State Forest Land
Aquatic Management Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
Moderate
SAINT LOUIS COUNTY
Industrial Township
Brevator Township
Riverlands State Forest
Brevator Woods
Aune Road Bog
Cloquet River
Beartrap Creek
Johnson Creek
Dutch Slough
Grand Lake Swamp
69472
69485
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ISA Combined Application
Docket Nos. E015/CN-25-111 and E015/TL-25-112
Appendix G
Page 31 of 34


IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
Detailed Map
Appendix G
Page 14 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
69 kV
115 kV
230 kV
DC Line
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Cemetery
Gravel Pit/Rock Quarry
County Boundary
Tribal Boundary
Township
PLS Section
Rail Lines
Minnesota Snowmobile Trail
State Park Trail / Road
State Trail
State Forest
Other State Forest Land
Aquatic Management Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
MBS Sites of Biodiversity Significance
Moderate
SAINT LOUIS COUNTY
Cloquet Trails
Industrial Township
Johnson Creek
Aune Road Bog
Little Grand
Grand Lake Township
Brevator Township
Solway Township
WHITE PINE RIVER AMA
Beaver
Dutch Slough
Sawyer Grader/Lumberjack Multi-use Trail
St. Louis River
Riverlands State Forest
Brevator woods
FOND DU LAC RESERVATION
Brevator Cemetery
Pine River
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S14 T50 R170
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IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT
minnesota power
AN ALLETE COMPANY
merjent
Detailed Map
Appendix G
Page 15 of 16
Project Substation
Proposed Route
Proposed Right Of Way
Proposed Alignment
Segment 1
Segment 2
Segment 3
Existing Tranmission Line
115 kV
230 kV
DC Line
Residential Structure in Route
Non-Residential Structure in Route
Residential Structure
Non-Residential Structure
Cemetery
Government Office
Place of Worship
Gravel Pit/Rock Quarry
County Boundary
Township
PLS Section
Rail Lines
Other State Forest Land
Aquatic Management Area
Water Access Site
Public Water Watercourse
Public Ditch/Altered Natural Watercourse
Public Waters Basin/Wetland
DNR Waterbody
DNR Stream/River
SAINT LOUIS COUNTY
Solway Cemetery
Solway Town Hall
Pine River
Hay Creek
WHITE PINE RIVER AMA
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69592
69387
69371
69370
69372
69203
0 1,000 2,000 Feet
ISA Combined Application
Docket Nos. E015/CN-25-111 and E015/TL-25-112
Appendix G
Page 33 of 34

IRON RANGE—ST. LOUIS COUNTY—
ARROWHEAD 345 kV TRANSMISSION PROJECT

minnesota power
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Minnkota Power Cooperative

Detailed Map
Appendix G
Page 16 of 16

- Project Substation
- Proposed Route
- ATC Arrowhead Substation Expansion
- Existing ATC Arrowhead Substation
- St. Louis County Substation Expansion
- HVDC Modernization Footprint
- Proposed Right Of Way

Proposed Alignment
- Segment 1
- Segment 2
- Segment 3

Existing Transmission Line
- 115 kV
- 230 kV
- DC Line
- Residential Structure in Route
- Non-Residential Structure in Route
- Residential Structure
- Non-Residential Structure
- Government Office
- Place of Worship
- Gravel Pit/Rock Quarry
- County Boundary
- City/Municipality
- Township
- PLS Section
- Private Airport
- Rail Lines
- Minnesota Snowmobile Trail
- Other State Forest Land
- Aquatic Management Area
- Water Access Site
- Public Water Watercourse
- Public Ditch/Altered Natural Watercourse
- Public Waters Basin/Wetland
- DNR Waterbody
- DNR Stream/River

0 1,000 2,000 Feet

Segment 2 End
Segment 3 Start
Segment 3 End
Arrowhead Substation
St Louis County Substation
SAINT LOUIS COUNTY
Midway Township
Solway Township
Thomson Township
West Rocky Run
Midway River
Elm Creek
Hermantown Missing Link Trails
Solway Town Hall
MN 2
MN 23
MN 53
MN 210
MN 194
MN 45
MN 61
MN 33
MN 39
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MN 24
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MN 194
MN 45
MN 61
MN 33
MN 39
MN 73
MN 24

Segment 3 End
Arrowhead Substation

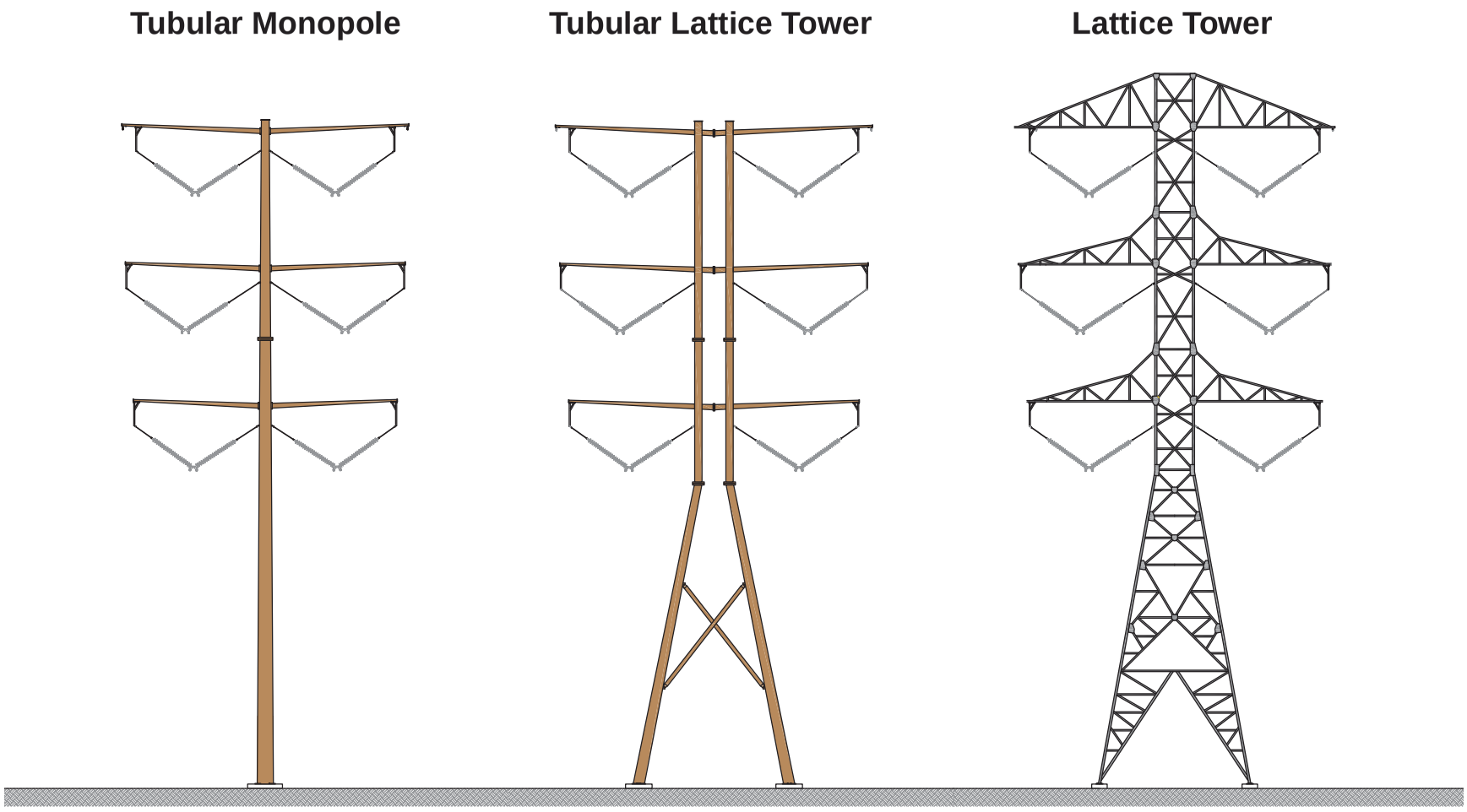
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Aitkin
St. Louis
Carlton

APPENDIX H

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

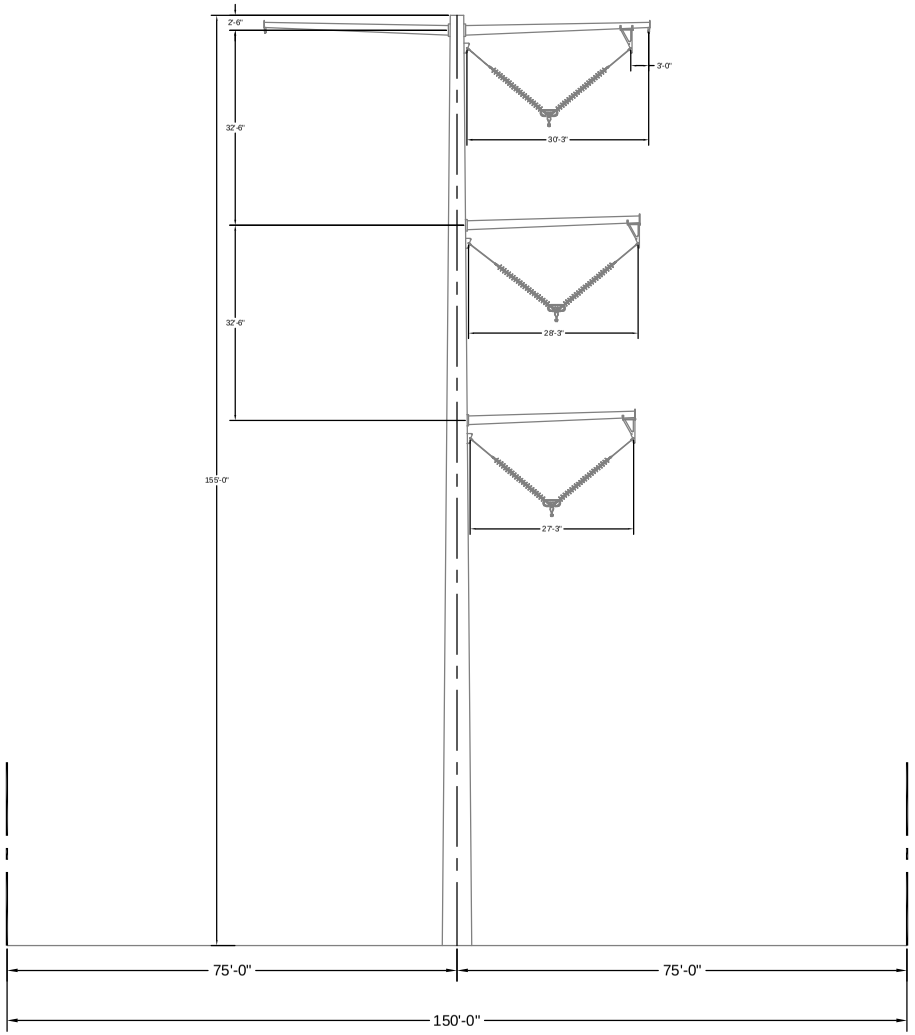
TECHNICAL DRAWINGS OF PROPOSED STRUCTURES

Potential Structure Design Concepts



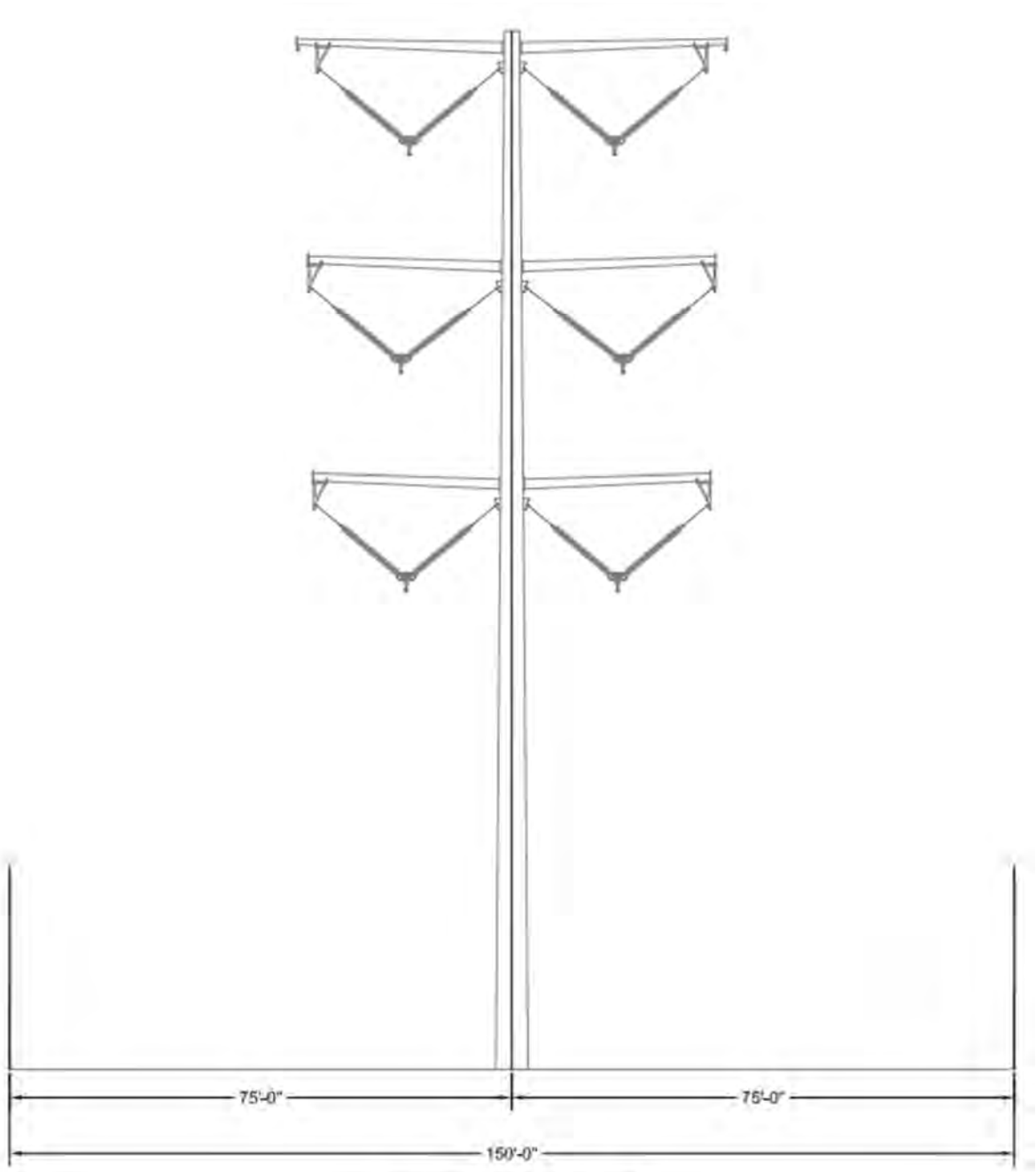
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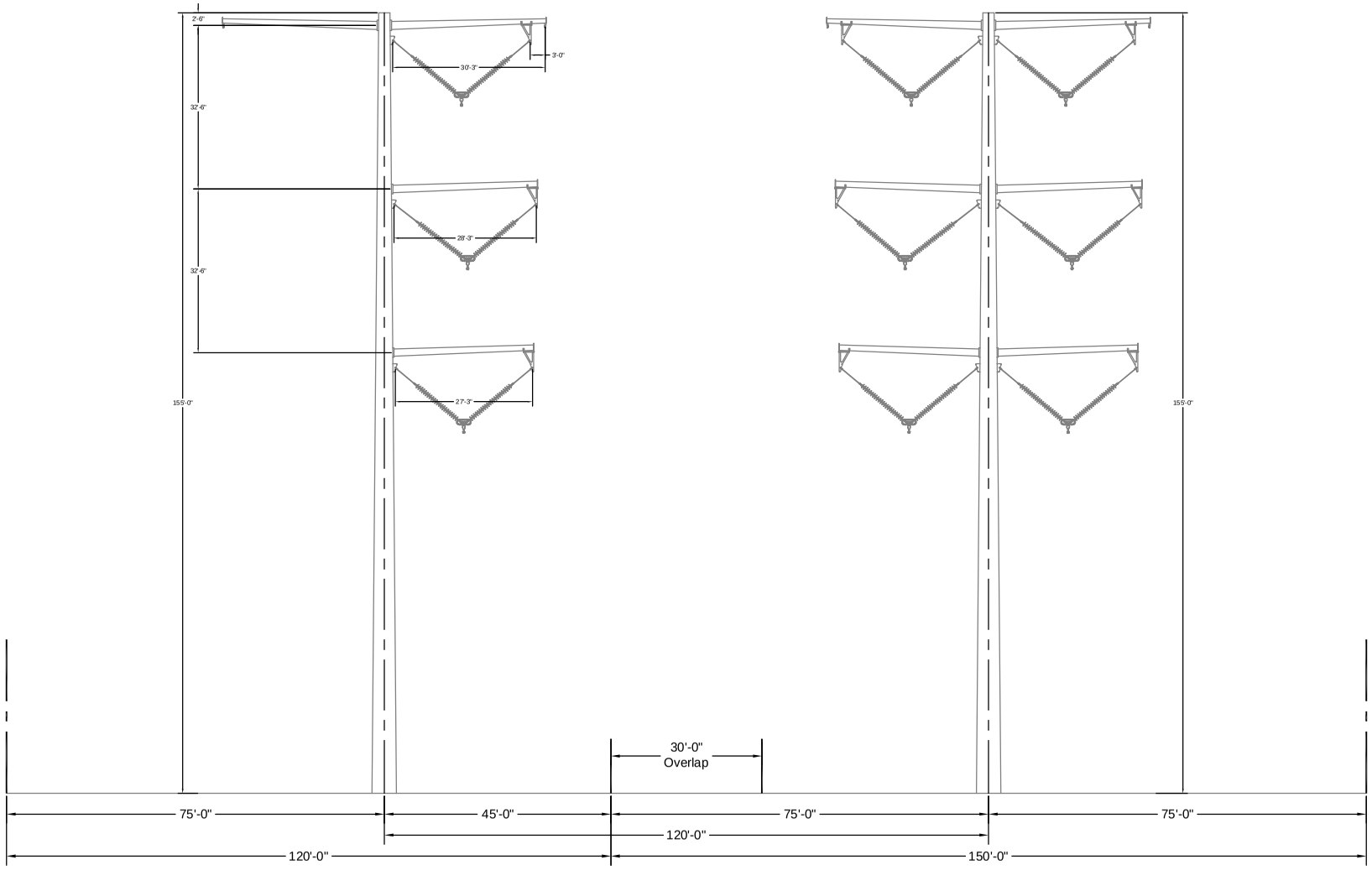


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875' RS - 965' Max Span

CROSS-SECTION O
345kV Single Circuit



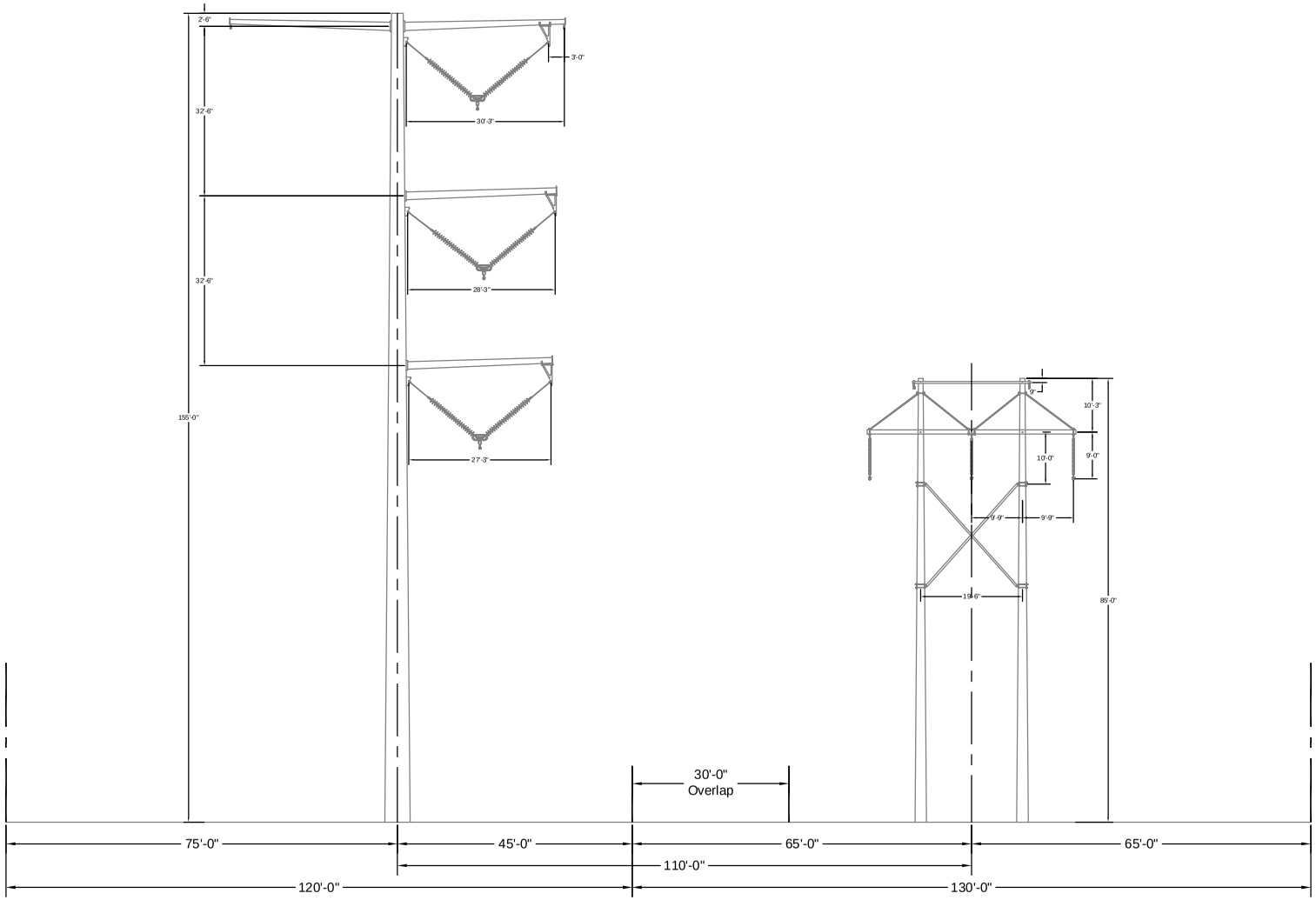
345kV V-STRING TANGENT



345kV SINGLE CIRCUIT V-STRING TANGENT
875' RS - 965' Max Span

345kV NRP V-STRING TANGENT

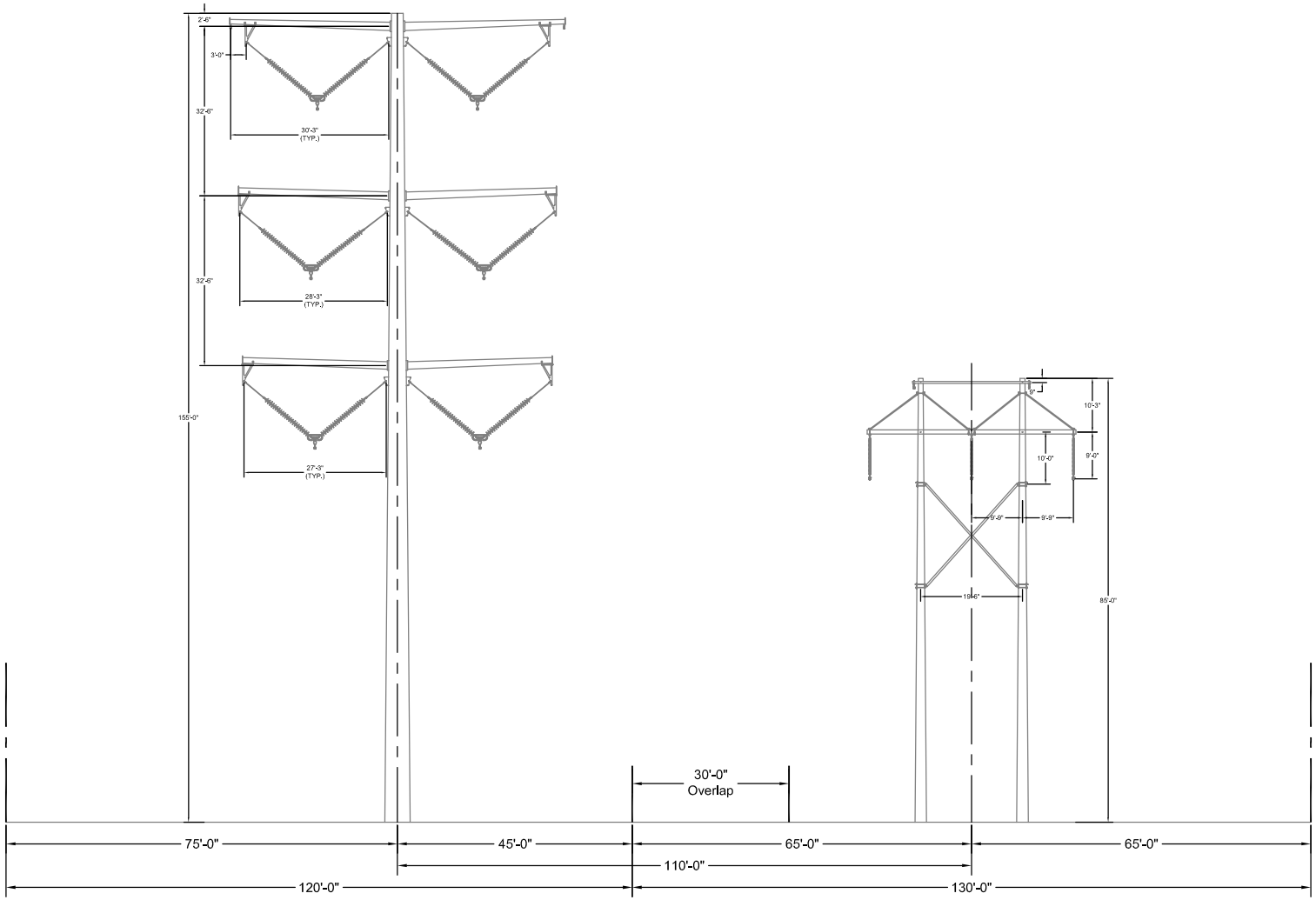
CROSS-SECTION Q
345kV Single Circuit Parallel to 345kV Double Circuit



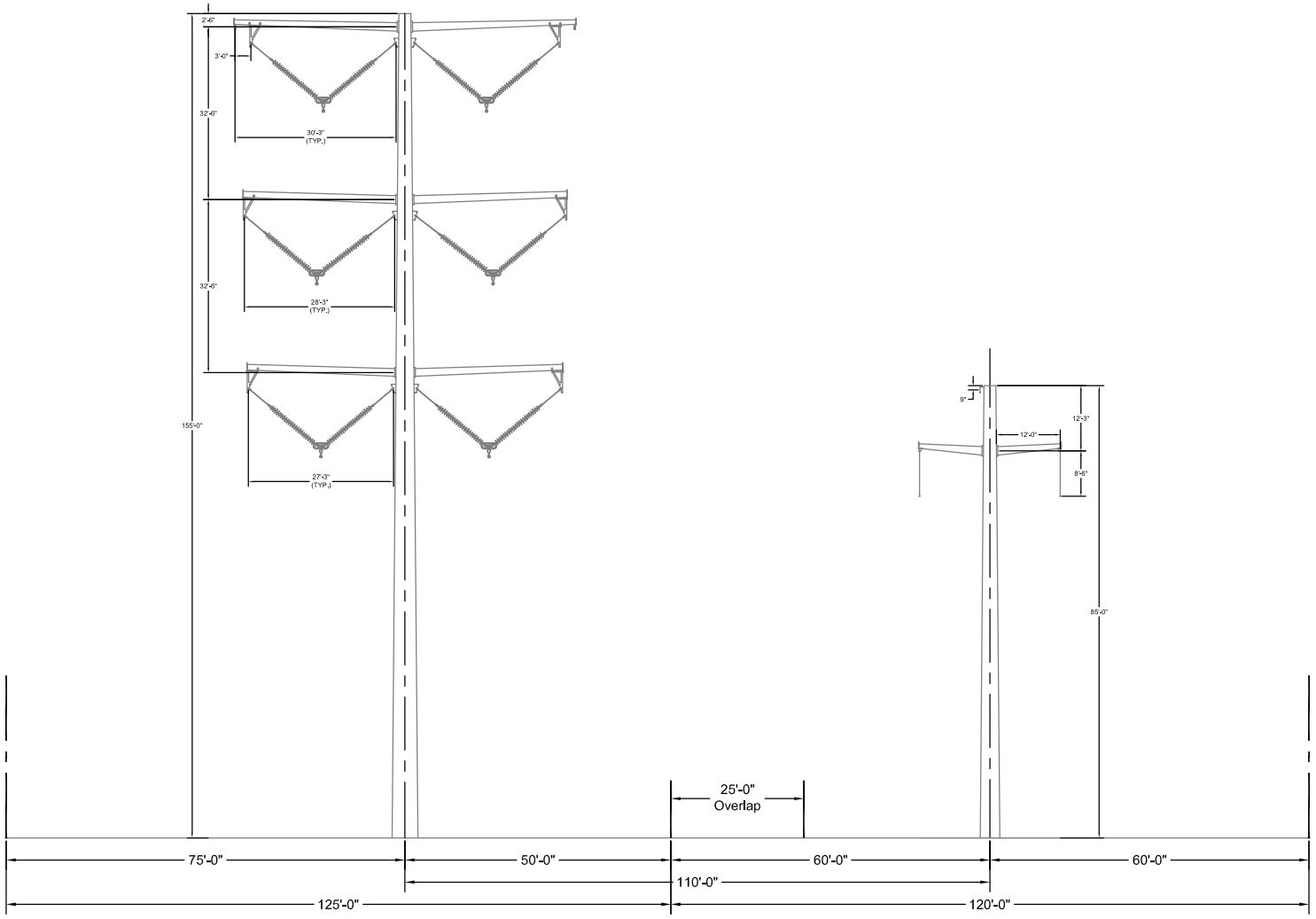
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875' RS - 965' Max Span

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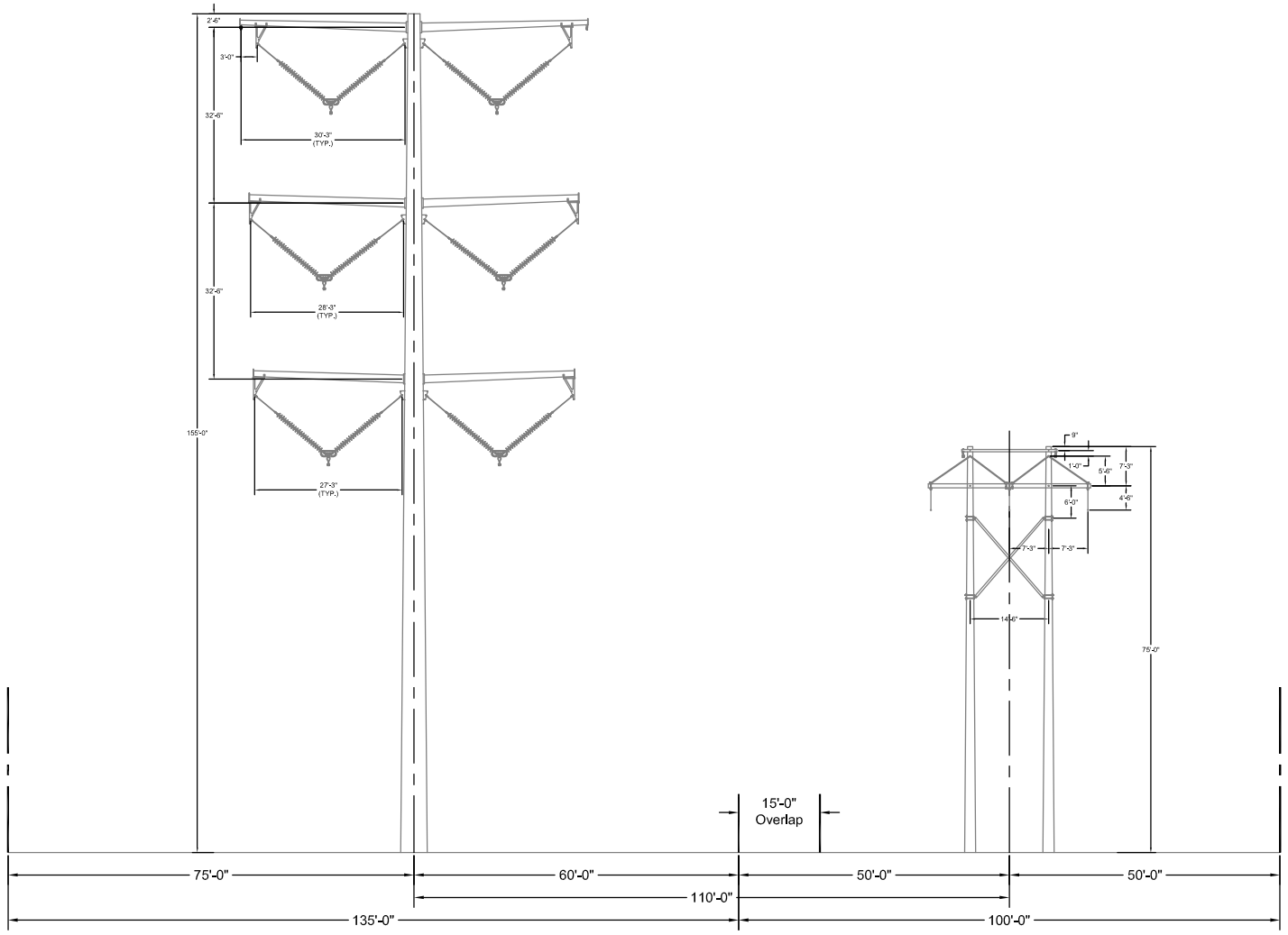
CROSS-SECTION P
345kV Single Circuit Parallel to 230kV



CROSS-SECTION B
345kV Parallel to 230kV



CROSS-SECTION C
345kV Parallel to 250kV-DC



CROSS-SECTION G
345kV Parallel to 115kV

APPENDIX I

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

MISO LRTP TRANCHE 2.1 PORTFOLIO REPORT

MTEP24 Table of Contents

Chapter 2: Regional / Long Range Transmission Planning 3

2.1 Overview 3

Tariff Requirements 3

History 4

Tranche 1 5

2.2 The Planning Process 6

Seven-Step Process 7

Stakeholder Engagement 8

Step 1: Establish Futures and Siting 9

MISO Futures 9

Resource Expansion 10

Resource Siting 11

Energy Adequacy and PROMOD Analysis 12

Low-End Bookend 13

Step 2: Develop Planning Models Utilizing Futures 14

Reliability Models 14

Economic Models 17

Step 3: Identify Transmission Issues 21

Reliability Analysis 21

Transfer Analysis 23

Dynamic Assessment 24

Voltage and Reactive Support 25

Economic Analysis 25

Economic Metrics 26

Reliability and Economic Analysis Results 28

West Region 32

Central Region 33

East Region 34

Step 4: Propose Solutions 35

Refining Solutions 36

Refine Solutions 62
Step 5: Evaluate and Justify Solutions 63
Total Reliability Results 63
Total Economic Results 70
West Region – Reliability and Economic Results 77
Central Region – Reliability and Economic Results 97
East Region – Reliability and Economic Results 115
Business Case Analysis 125
Future 2A Benefit Metric Analysis 127
Step 6: Recommend Preferred Solutions 144
Step 7: Apply Appropriate Cost Allocation 146
Distribution of Benefits and Portfolio Costs 146
2.3 Near Term Congestion Study Update 151
Introduction and Background 151
Study 153
2024 Near-Term Congestion Study Report 156

Chapter 2: Regional / Long Range Transmission Planning

2.1 Overview

Under the Reliability Imperative's Transmission Evolution pillar, MISO is transforming how it plans for and manages the grid of the future, given all the complex changes underway. As part of this effort, Long Range Transmission Planning (LRTP) develops backbone regional projects to ensure the transmission system is reliable, economic and compliant in the future based on state and utility policy and goals, projected conditions and industry trends. This is accomplished while demonstrating the transmission portfolio provides benefits in excess of costs and value that is consistent with MISO's Tariff criteria. LRTP tackles needs and issues that are not easily addressed in cyclical planning processes like MISO's MTEP, which focuses on more near-term needs. Instead, it looks at a long-range (roughly 20- to 40-year) view of the system and provides a roadmap or vision to address those future issues, while also guiding near-term transmission planning.

From a transmission planning perspective, LRTP looks comprehensively at the MISO region in collaboration with stakeholders. While its resulting portfolios enable a reliable and efficient grid based on forecasted resources, they are not intended to resolve every issue associated with precise siting of future generation or load. As a result, LRTP portfolios are "least-regrets" to plan for an uncertain future based on the needs reflected in policy and member plans that are current at the time of modeling and analysis.

The overall LRTP effort is large and complex, unlike any effort MISO or any other organization has undertaken in the history of the grid. It takes a long time to plan for comprehensive regional solutions, especially when managing against a great deal of uncertainty. Additionally, LRTP has to be conducted over the course of rapid evolution as business plans, federal and state energy/environmental policies and other dynamic factors that affect the region's transmission needs continually change.

Tariff Requirements

Categorized as Multi-Value Projects (MVPs) under MISO's tariff, LRTP solutions must meet the following requirements: enable the transmission system to deliver energy reliably and economically, in support of documented energy policy mandates or laws; provide multiple types of economic value with a benefit-to-cost ratio of 1.0 or greater; or address at least one reliability issue and provide at least one type of transmission-based economic value. Additionally, an MVP cost allocation methodology must be applied—one that spreads costs footprint-wide on a load-ratio share basis, or spreads costs to a subregion only if benefits are primarily provided to that single subregion.

History

Long-term transmission planning was not new to MISO when LRTP launched in 2020. MISO's initial regional, long-term study began in 2008 to address the integration of renewable energy required by state Renewable Portfolio Standards. It resulted in the Multi-Value Project (MVP) portfolio of projects, which was approved in 2011 and fully constructed by 2024.

In 2019-2020, MISO began to formulate a strategy for LRTP. After cities, states, large commercial and industrial corporations and utilities started setting aggressive renewable and decarbonization goals, MISO members asked MISO to quickly move on long range transmission planning to align with their goals, preferences and investment decisions. In its own studies, like the Renewable Integration Impact Assessment (RIIA), MISO gained insight on significant system issues which would result from the continuing transition of the resource portfolio towards much higher weather-based renewable resources. Paramount to RIIA's findings was the fact that greater penetrations of renewable resources required new transmission to ensure system reliability. Additionally, the transfer capability realized because of this transmission buildout would provide better regional connectivity and thereby reduce the amount of generation capacity that would be needed to meet resource goals.

The job of LRTP is to enable a reliable generation fleet as planned by MISO Members and states. Based on RIIA and the Futures which had been recently updated, MISO knew the industry drivers and high level issues which informed the development of a conceptual, indicative roadmap (see Figure 2.1: Indicative Roadmap). Among other things, the roadmap is an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures. It was contemplated by MISO planning staff as an extension of the existing grid that could provide logical connections that increase connectivity, close gaps between subregions and support a more resilient grid by enabling more transfers of bulk power flows. The roadmap is not a plan, but provides a basis to guide conversations and consider solutions to expected transmission issues. Although solutions in the roadmap may not ultimately meet the necessary requirements to become projects in MTEP Appendix A, the roadmap provided and continues to provide a foundation from which to work.

Because of the magnitude of the needs and the study efforts required to determine solutions, MISO is approaching this large endeavor in tranches, beginning with a focus on the Midwest for Tranches 1, 2.1 and 2.2, moving later to the South region in Tranche 3 and the Midwest-South connection in Tranche 4. In its initial plan, MISO envisioned two tranches for the Midwest but during Tranche 2 planning, recognized the needs of the Midwest should be addressed in three phases. As a result, Tranche 2 was renamed 2.1 and Tranche 2.2 was added.

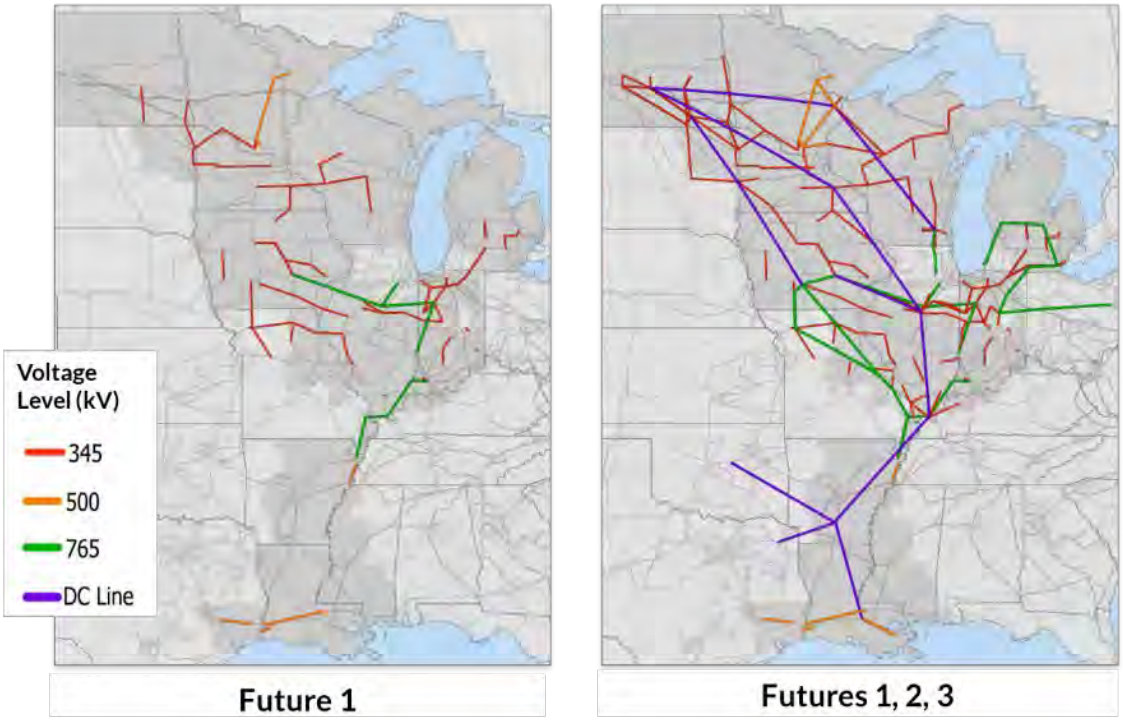


Figure 2.1: Indicative Roadmap

Tranche 1

Approved in July 2022 as part of MTEP21 Appendix A, the Tranche 1 portfolio totals $10.3 billion, consists of 18 projects spread across the entire MISO Midwest subregion and benefits multiple states, MISO members and customers. Planning for Tranche 1 began in 2020 following the development of new Futures Series 1 that reflected policy changes and the plans of states, utilities, and members. Tranche 1 solutions addressed approximately 30% of issues that were identified. Analysis was based on Future 1 and a Multi-Value Project (MVP) cost allocation approach will spread the costs of projects pro-rata to load across the MISO West, Central and East regions (Midwest subregion). A wide range of value will be provided, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

With a Tariff requirement to provide benefits that are commensurate with costs, the full portfolio has a benefit-to-cost ratio of 2.6 - 3.8, which is well in excess of costs, and a benefit-to-cost ratio of at least 2.1 for every MISO zone. MISO's planning maximized the use of existing rights-of-way, which helped reduce the typical challenges in the regulatory process stemming from siting and acquisition of new rights-of-way.

As of July 2024, many projects are well into regulatory approval processes, with MISO supporting constructing Transmission Owners in these efforts. MISO will monitor the status of these projects through the build phase and utilize its variance analysis process to deal with any costs or schedule changes that exceed certain, established criteria, and other project scope or construction challenges that could put at risk getting the projects in service.

2.2 The Planning Process

The magnitude of change planned for the future is now more significant than it was just a few years ago when MISO developed Tranche 1. It requires prompt action to address the fast pace of transformation occurring in the industry. To ensure MISO identifies a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs, a rigorous analysis by MISO with stakeholder engagement was conducted.

For Tranche 2.1, MISO followed its iterative seven-step process to build models, identify issues and test potential solutions, with over 40,000 staff hours invested in the study. Stakeholders were engaged in the process, with more than 300 meetings in various formats and forums, numerous one-on-one discussions, email exchanges and more. A reliability study whitepaper, economic study whitepaper, business case analysis whitepaper, models, scenarios and all key data inputs and analysis results were posted and reviewed by stakeholders. Additionally, formal and informal feedback was received and considered throughout the process, and appropriate updates were implemented based on feedback.

Models focused on Future 2A from the 1A series represented credible system conditions with likely and possible dispatch patterns determined following a data-driven process. Steady state, transfer and transient stability analyses were performed to ensure transmission system performance is reliable and adequate before and after contingencies (disturbances) occur. Economic analyses[1] were performed to evaluate congestion, generation curtailment, regional price separation and overall costs to serve load and to understand the impacts to overall Adjusted Production Cost savings.

To consider opportunities with existing and emerging technologies, MISO reviewed impacts of transmission technology concepts with stakeholders at the Planning Advisory Committee in 2023, discussing 345 kV, 765 kV, High Voltage Direct Current (HVDC) and Grid Enhancing Technologies (GETs). This presentation focused on high-level approaches with technology considerations and the potential impact of thermal and absolute limits, given factors like MW per mile cost and loading limits. For many of the new transmission line needs identified in LRTP Tranche 2.1, the necessary line mileages and power transfer requirements suggested that a 765 kV backbone would be the optimal choice at this stage. Grid Enhancing Technologies tend to work best when they are used to solve local issues, and were considered and selected for certain underbuild projects. Static synchronous series compensator technology was selected for one of the underbuild solutions as a flow control solution.

MISO also conducted robustness testing to determine the potential impact of key projects already approved or under consideration after LRTP power flow models were completed in October 2023. This assessment looked at select MTEP23 and MTEP24 projects, the JTIQ projects and the Grain Belt Express (GBX) Merchant High Voltage Direct Current project, and determined these projects do not negate the need for the Tranche 2.1 portfolio. Additionally, MISO received nearly 100 alternative solutions from stakeholders representing 47 solutions. After the evaluation process, some alternatives were incorporated into the portfolio.

In its final analysis and consideration of stakeholder feedback, MISO concluded the Tranche 2.1 portfolio boosts reliability and economic value, enabling member fleet transitions, load growth and regional power

[1]Consists of utilizing production cost models that simulate chronological dispatch for an entire year (8760 hours). For additional information please refer to MISO Economic Planning Whitepaper.

transfer within MISO, when geographic diversity must be relied upon to help manage dispatch flexibility during a range of operating conditions.

Seven-Step Process

Through a seven-step iterative process (Figure 2.2: MISO's 7-Step Process), MISO plans, assesses, evaluates and repeats steps as necessary to ensure a least-regrets plan. It begins with development of the Futures with stakeholders, based on a minimum 20-year horizon because transmission can take 8 to 12 years to identify, site and develop. MISO forecasts and sites generation resources, as well as load and energy growth. MISO then analyzes the ability of the transmission system to perform reliably and safely in delivering resources economically to load, recognizing member and state goals across the entire footprint.

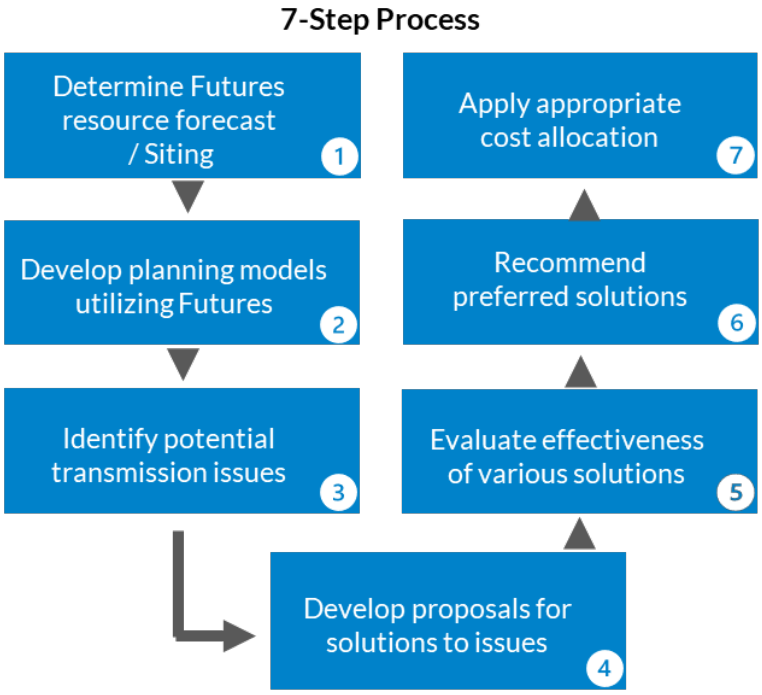


Figure 2.2: MISO's 7-Step Process

From there, MISO develops a conceptual long-range vision of the transmission system that could be needed to meet the Futures scenarios, with a focus on an incremental, subregional buildout based on the needs of each area. As solutions are identified, MISO considers the value of various transmission options in terms of reliability, economic and other factors.

Before choosing solutions to identified issues, guardrails are applied in several scenarios to show reliability and economic value considering how any subregional upgrades may fit into the conceptual long-term plan so MISO doesn't make shorter-term design decisions that would make the future development more costly — for example, effective use of right-of-way — constructing for higher voltages and operating at a lower voltage where that makes sense.

LRTP's focus is on regional transmission solutions, rather than resolving all localized issues. MISO recognizes some issues will be more appropriately addressed by annual MTEP reliability planning and

generator interconnection processes. The LRTP planning process and the reliability component of the NERC TPL annual reliability planning process have related, but distinct objectives. The NERC TPL annual reliability planning process is a compliance-based planning process that ensures the transmission system is planned to address reliability needs in the short-term (i.e., five-year planning horizon, etc.) and relies on known and committed inputs. LRTP is focused on regional and long-term issues that require regional and long-lead solutions. It is not designed to replace the shorter-term generator interconnection and annual reliability planning processes, but instead focuses on broad regional issues that are not sensitive to changes in input assumptions as well as long lead solutions that significantly reduce life cycle costs in the long-term costs and require advanced planning to implement.

Stakeholder Engagement

MISO could not complete this work without stakeholder input. Its transmission planning is conducted through a stakeholder process. In addition to regular stakeholder meetings, MISO provides other opportunities to encourage and ensure strong engagement, such as stakeholder feedback requests.



Figure 2.3: Tranche 2.1 Journey

From Planning Advisory Committee (PAC) meetings that analyze identified issues and proposed solutions, to deep dives in LRTP workshops, and so much more, there have been at least 300 meetings – both internal and external – to arrive at the Tranche 2.1 portfolio. With strong interest in LRTP, workshops averaged 275 participants and multiple other meetings and in-depth discussions were held. Among these various stakeholder meetings, MISO utilized both its public Stakeholder Feedback Tool and its LRTP email to elicit much of the feedback received and inform the inputs, scope and metrics for the Long Range Transmission Panning process. MISO reached out to Stakeholders 10 times across two years for Formal/Informal feedback thru the Feedback Tool; this combined with oral feedback received at LRTP workshops to shape the processes and portfolio. An example of feedback from the Feedback Tool and LRTP email includes:

- The Futures and Siting process was informed by 500+ stakeholder revisions impacting the inputs of the process

- MISO received significant stakeholder feedback and used that feedback to implement changes to the reliability and economic models throughout multiple months
- Stakeholder feedback informed the transfer scenarios selected as part of the scope
- Feedback was instrumental in informing the business case metrics

After sharing its rationale for planning approach, analysis and key decisions, MISO is confident it has developed a least-regrets, robust portfolio.

Step 1: Establish Futures and Siting

LRTP's planning begins with forward-looking planning scenarios called Futures, which capture a range of economic, political, and technological possibilities over a twenty-year period, provide potential resource mixes, and appropriately bookend future uncertainty. The Futures are based on member data, stakeholder input, state and federal policy, and technical and economic data like the DOE's National Renewable Energy Lab (NREL) Annual Technology Baseline. MISO defined three Futures which co-optimize several parameters to minimize total costs in achieving member goals, including peak demand plus reserve margin, annual energy, decarbonization goals and renewable portfolio standards/clean energy goals.



Figure 2.4: MISO Futures

MISO Futures

To develop Futures, MISO follows a rigorous, stakeholder-driven process to bridge the gap between what members plan for the future and the generation needed to get there. The original Futures are referenced as Series 1 (Futures 1, 2 and 3). The refreshed Futures, called Series 1A (Futures 1A, 2A and 3A) were initiated in July 2022. They provided the basis for the Future 2A resource expansion, which began in January 2023 with stakeholder engagement and included 500 siting changes based on feedback. Energy adequacy analysis was completed in April 2023 and was followed by capacity expansion modeling, siting, and production cost

modeling handoffs development for Futures 1A and 3A for MISO (and the three external areas modeled). Initial screening analyses was conducted in Summer 2023.

MISO posted the Series 1A Futures Report in Fall 2023 and then continued to conduct various screening analyses of the resource mix for the portfolio through January 2024. For Tranche 2.1, MISO determined Future 2A is most aligned with an optimized, least-cost expansion that meets member goals and Future 1A is an appropriate low-end bookend for the business case analysis.

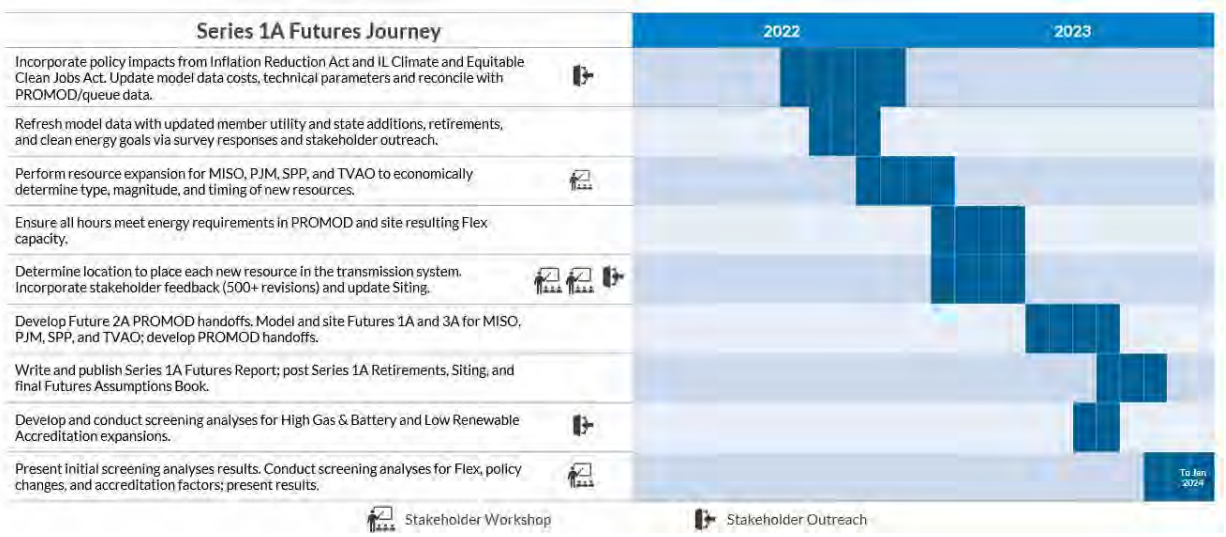


Figure 2.5: Series 1A Futures Journey

The Futures are periodically refreshed with key data inputs to help ensure the most accurate forecasts are used in planning. Subsequent refreshes will be driven by the timing and pace of planned new generation based on policy, load and other drivers of change.

Resource Expansion

Since MISO is not an integrated resource planner, MISO Futures reflect resource plans announced by member utilities and states. MISO is obligated to reflect and define a resource expansion that aligns with these plans. As such, transmission planning works to ensure the energy planned by members can be delivered to where it's needed. Additional future resources beyond member plans are required to meet projected load, policy objectives, and reserve margins. To bridge this gap, MISO performs an economic resource expansion analysis, which forecasts the additional resources to meet system needs at lowest cost.

For more than a decade, MISO has utilized a transmission-less, non-chronological resource modeling tool for transmission planning analysis. MISO develops a least-cost resource expansion with total costs linked to key assumptions, which grounded the Futures. Several notable outcomes from these key assumptions on Future 2A include:

- **Generation Additions and Retirements:** For additions, 54% of the F2A expansion originates from member-planned resources. For retirements, MISO used member data and applied age-based retirement assumptions in cases for which no feedback was provided on generator retirement dates. For example, member data directly provided approximately 77% of coal retirements.

- **Load:** MISO benchmarked its load forecast with McKinsey & Company in 2022 and found load projections fell within Future 2A and Future 3A with annual energy similar to Future 3A.
- **Incentives:** The Inflation Reduction Act provides various incentives for battery, solar, hybrid and wind, which lower their respective overall costs through investment or production tax credits.
- **Resource Type Cost Modeling**: Resource operations and maintenance (O&M) costs are offset by incentives (Inflation Reduction Act), with wind costing the lowest and hybrid and battery the highest.
- **Decarbonization Goals:** 75% of MISO load is served by members with ambitious decarbonization and/or renewable energy goals.
- **Battery Storage Assumptions:** By utilizing excess energy for charging, battery storage plays an important role in the Futures expansion to minimize the overall resource fleet cost. Future 2A includes 11 GW of member-planned battery and 20 GW of model-built battery, for a total of 31 GW of 4-hour lithium-ion battery.
- **Accreditation:** Capacity accreditation was based on the approved 2022 Planning Resource Auction and shifts over time based on the Renewable Integration Impact Assessment (RIIA)

A full list of the Futures assumptions is included in the Futures Refresh Assumptions Book.

Resource Siting

Futures development culminates in a siting process that maximizes resource availability and accommodates member goals. After the expansion, siting analysis ensures these resources can be built in needed areas. MISO followed a stakeholder-approved siting process which was covered in the Series 1A Futures Report and Futures Refresh Assumptions Book. As part of this process, MISO sited model-built resources to address the following:

- Local/regional Renewable Portfolio Standards (RPS) and decarbonization goals
- 80/20 split between Generator Interconnection (GI) queue and Vibrant Clean Energy (VCE)/Greenfield Sites for renewable resources, with:
    - Up to 80% of Wind, Solar, or Hybrid sited at Active Definitive Planning Phase (DPP) 1, 2, or 3 Generator Interconnection (GI) Queue or Tranche 1-enabled sites
    - Remaining ~20% sited at VCE-identified areas with renewable potential
- Each Local Resource Zone (LRZ) meeting its Local Clearing Requirement (LCR) and Planning Reserve Margin Requirement (PRMR)
- Capacity sited at 5-year milestone intervals (2027, 2032, 2037, 2042)

Once the expansion was determined, MISO worked with stakeholders to determine appropriate resource sites, including over 500 revisions based on extensive stakeholder feedback:

- Made significant modifications to the sited wind across the MISO footprint, including:

- Moved all preliminary sited MISO South model-built onshore wind to MISO Midwest (primarily North Dakota and South Dakota)
- Moved ~60% of member-planned onshore wind in MISO South to SPP as a planned external resource
- Moved wind in Wisconsin and northern Minnesota to North Dakota and South Dakota

- Situationally re-sited capacity at provided/preferred buses:
    - Redistributed solar and solar hybrid to include more of these resources in MISO South and Wisconsin
    - Re-sited thermal capacity from MN and IL to locations provided by stakeholder feedback
- Redistributed Demand Response and distributed generation photovoltaic (DGPV) resources over additional sites
- Incorporated additional member-planned resources, primarily energy storage and Reciprocating Internal Combustion Engines (RICE)
- Reduced offshore wind due to a 54% reduction of the Wind Energy Area (WEA) affecting the size and availability of Bureau of Ocean Energy Management (BOEM) leasing sites near LA and TX.

Energy Adequacy and PROMOD Analysis

An example that demonstrates managing uncertainty through MISO's comprehensive, iterative process is how MISO assessed energy adequacy during analysis to arrive at Future 2A. An energy adequacy analysis ensures the grid can be operated reliably, meeting energy needs during all hours with the forecasted resource mix—an important step given the increase in intermittent resources. Through planning, analysis revealed an energy shortfall during what MISO has called the twilight hours—at sunset and sunrise—when wind output is typically low and solar output is unavailable.

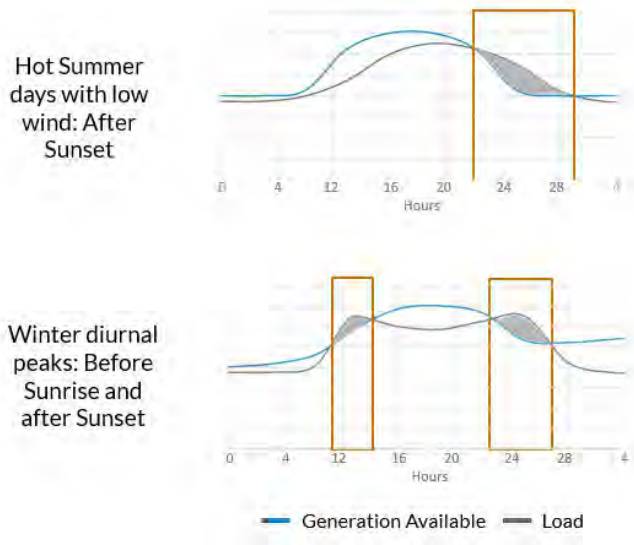


Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units

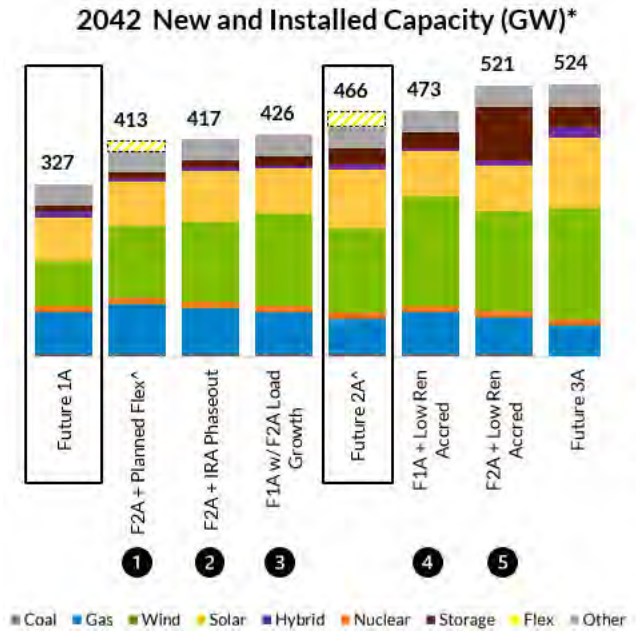
PROMOD, a production cost modeling tool providing hourly (annual) chronological security-constrained unit commitment and economic dispatch, identified generation shortfalls for three to four hours per day during twilight hours (before sunrise or at sunset) in up to 26 days of the modeled year, with a maximum shortfall of 29 GW in a single hour. To address this energy shortfall, 29 GW of supplemental low- or no-emitting, high availability resource additions, referred to as Flex for Flexible Attribute Units, were needed to ensure energy adequacy during these time periods. This is reflected in the shaded areas of both graphs in Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units.

These "Flex" units represent potential generation that is highly available, highly accredited, low- or non-carbon-emitting and long in duration. Flex resources could be, but are not limited to the following: Reciprocal Internal Combustion Engine (RICE) units, long-duration battery (>4 hours), traditional peaking resources, combined cycle with carbon capture and sequestration, nuclear Small Modular Reactors (SMRs), green hydrogen, enhanced geothermal systems, and other emerging technologies.

Low-End Bookend

MISO's LRTP processes define a robust portfolio of transmission to achieve the energy goals of MISO states and members under a range of conditions. Part of this robustness is achieved through ensuring the models used in scenarios appropriately bookend future uncertainty and capture potential resource mixes. The Resource Expansion results drive the selection of transmission solutions.

As such, MISO conducted multiple screenings assessing the impact of different changes on the resource mix and validated Futures 2A and 1A as appropriate bookends. Many of the screens performed showed resource mixes similar to Future 2A; as a result, MISO proceeded with Future 1A as the low-end bookend.



	Screening	Details
1	Future 2A + Planned Flexible Attribute Units	Inclusion of 29 GW of Flexible Attribute units as planned gas units
2	Future 2A + Inflation Reduction Act Phaseout	Assumed phaseout of Inflation Reduction Act provision after 2030
3	Future 1A + Future 2A Load	Expansion using F1A goals and retirement assumptions and F2A load growth
4	Future 1A + Low Renewable Accreditation	F1A with wind and solar resource receiving 5% capacity credit
5	Future 2A + Low Renewable Accreditation	F2A with wind and solar resource receiving 5% capacity credit

Figure 2.7: Futures Low-End Bookend

Step 2: Develop Planning Models Utilizing Futures

Reliability Models

MISO built 10-year, and 20-year reliability models based on Future 2A for LRTP reliability analysis. As part of this analysis, MISO tested transmission reliability under likely and possible dispatch with a focus on the worst credible conditions from the system point of view, while recognizing that local conditions may vary.

A set of base models were used to assess the impact of variable renewable and hybrid generation and other system conditions. These broad base models encompassed multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus providing the platform to perform a wide range of reliability studies.

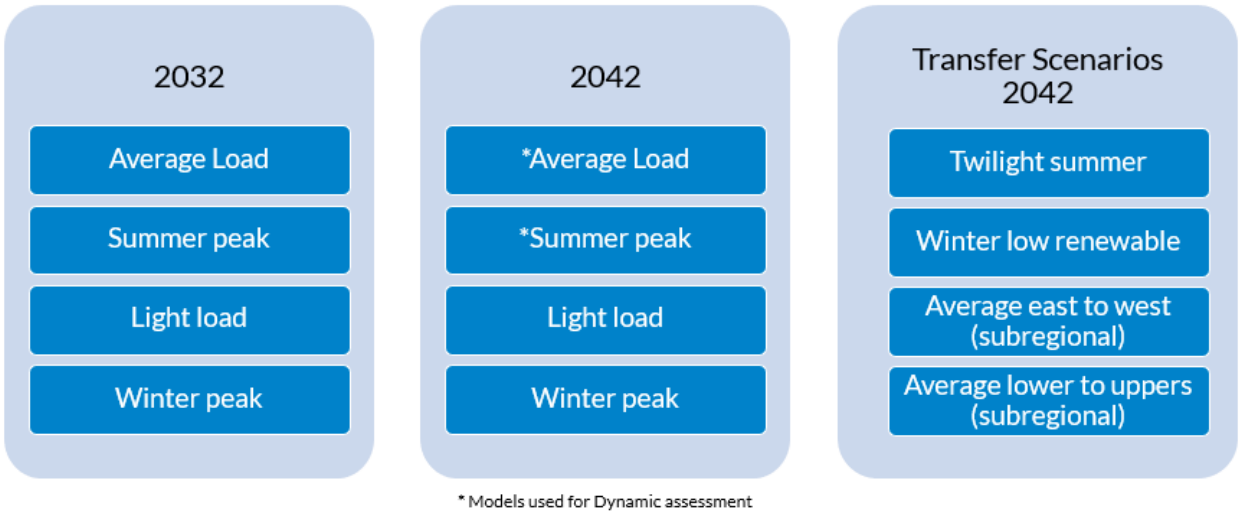


Figure 2.8: Core Models used in Reliability Assessment

Core models were determined via load points on the MISO annual load duration curve (see *Figure 2.9: Overview of load levels in Future 2A, Table 2.1)*. After selection of these load points, coincident output from wind and solar resource profiles were used to derive a credible dispatch for the given scenario. Figure 2.9 shows an overview of load levels in Future 2A, informing the selection of reliability models. To the right, the load duration curve is shown, highlighting the four desired load levels for the core models. The left shows a series of indicative daily load shapes and how they map to the load duration curve. These power flow models provided the basis for steady state, dynamic, voltage stability and additional scenarios. A more comprehensive explanation of reliability models and analysis is available in a MISO Reliability Study Whitepaper.

Core cases	Renewable and storage dispatch methodology	Reason for inclusion
Case 1: Summer Peak Load • Represents summer peak demand which is the highest load on the annual load duration curve	• High coincident renewable output in the summer between 90% and 100% of the annual peak demand • Storage off	• Test the ability to reliably serve load via variable renewable energy and conventional resources
Case 2: Winter Peak Load • Represents winter peak demand	• High coincident renewable output in the winter between 90% and 100% of the annual winter peak demand • Storage discharging at 50% nameplate	• Local/Regional/System load profile and peak is different from the summer case • Test ability of renewables to reliably serve load considering load profile diversity • Test system ability to export to Manitoba Hydro
Case 3: Average Load • Represents typical system conditions within 70-80% on the load duration curve	• High coincident renewable output between 70% and 80% of the annual peak demand • Storage charging at 60% nameplate	• Assess system ability to move power and reliably serve load during the annual maximum coincident wind/solar, which is likely to occur during this timeframe • Peak variable renewable energy case is essential to evaluate dynamic performance
Case 4: Light Load • Represents lowest 10% on the load duration curve	• High coincident renewable output to test ability of the system to absorb reactive power • Storage charging at 60% nameplate	• Assess system conditions during low load, moderate wind, and zero solar output

Table 2.1: Core models

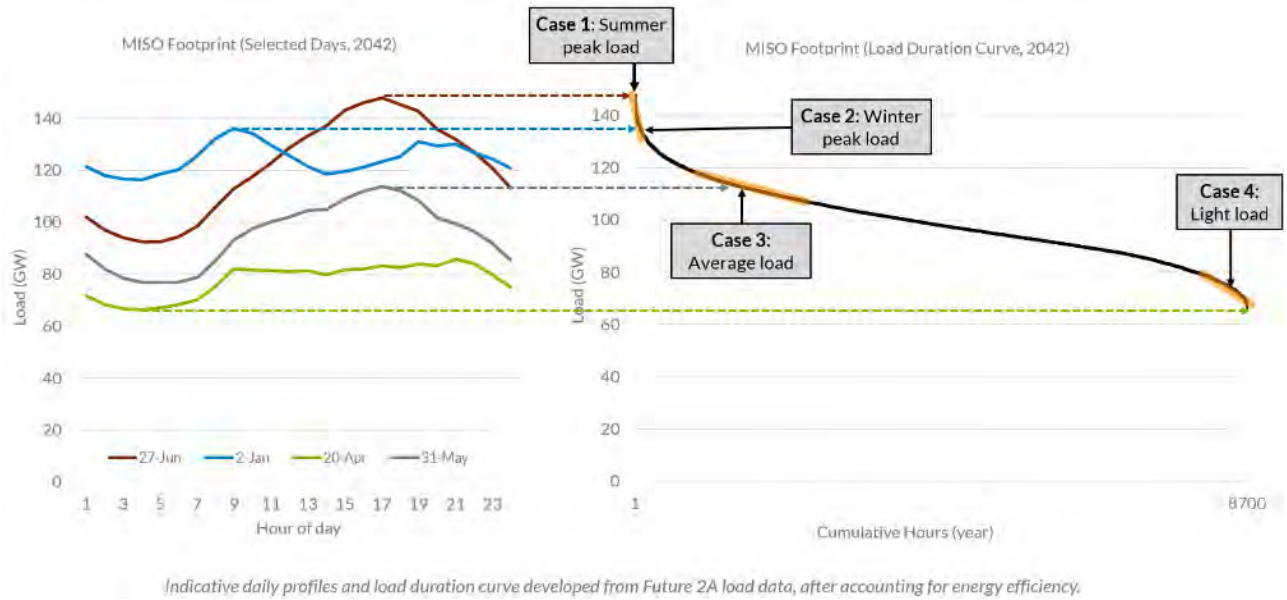


Figure 2.9: Overview of load levels in Future 2A

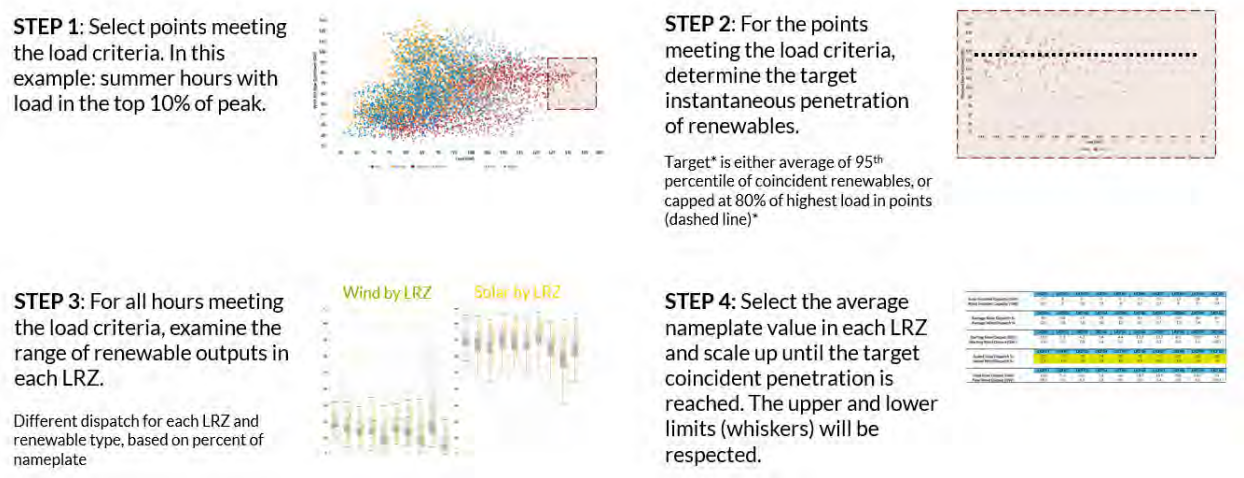


Figure 2.10: Overview of renewable dispatch methodology. This 4-step process provided a target variable dispatch for wind and solar resources specific to each LRZ. This served as a basis in the dispatch each of the core models.

Typically, powerflow models with high instantaneous penetration of renewable energy are challenging to solve. Furthermore, the retirements and additions from Future 2A represent a steep change from the starting models of MTEP22. Inverter Based Resources are modeled with a reactive power max (Qmax) and reactive power min (Qmin) at +/- 0.95 Power Factor based off the Power Generation (Pgen) of the unit. The units will adjust their reactive output within those limits to hold the scheduled voltage at the designated voltage-controlled bus Point of Interconnection (POI).

MISO has solved high renewable models through the Renewable Integration Impact Assessment (RIIA) and through building study models for the Definitive Planning Process (DPP) (i.e., interconnection queue). The goal of a power-flow model is to obtain a stable combination of voltages angle and magnitude information for each bus in a power system for specified load, generator, and topology conditions. Due to the nonlinear nature of this problem, to obtain a solution that is within an acceptable tolerance, the following issues may be experienced:

- The maximum real or reactive mismatch at any bus in the system exceeded
- The voltage magnitude and angle difference between buses too big or unknown
- The maximum number of iterations exceeded, etc.
- Voltage collapse and/or divergent solution

To solve the models, many methods may be required, such as:

- Additional fictitious reactive support devices
- Adjustment of model parameters including tap settings and voltage-controlled buses
- Localized generation curtailment if case approaches instability

- Model review to identify and rectify modeling issues

For each case MISO provided a summary of issues identified and methods (solutions) used to ensure modes are within acceptable tolerance. Once models were solved, the addition of fictitious resources, transmission lines, reactive resources or other model tweaks were re-examined for necessity and removed from the case to the extent possible.

Economic Models

MISO built 10-year, 15-year and 20-year economic models based on Future 2A for LRTP economic analysis. As part of this analysis, economic modeling utilizes PROMOD, a chronological security-constrained unit commitment and economic dispatch tool which applies a wide variety of operating constraints. Within the PROMOD model, Futures assumptions around load, generation, and fuel costs are incorporated up to a 20-year time horizon along with transmission grid topology and constraints to assess future transmission needs.

The economic model produces a unit commitment and security-constrained economic dispatch while optimizing production costs. The analysis allows simulation of all 8,760 hours in a year, not just the peak hour. The economic study model encompasses multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus allowing the model to perform a wide range of economic analysis.

Economic modeling and analysis rely on a 10-step process that starts with a core "No-Futures" model and ends with a "Final" economic model for portfolio development as shown in Figure 2.11. Throughout this process, MISO allows for touchpoints with stakeholders to incorporate feedback on models and flowgates, transmission issues and the portfolio, and to coordinate with the MISO reliability teams to sync issues and solutions across study work.

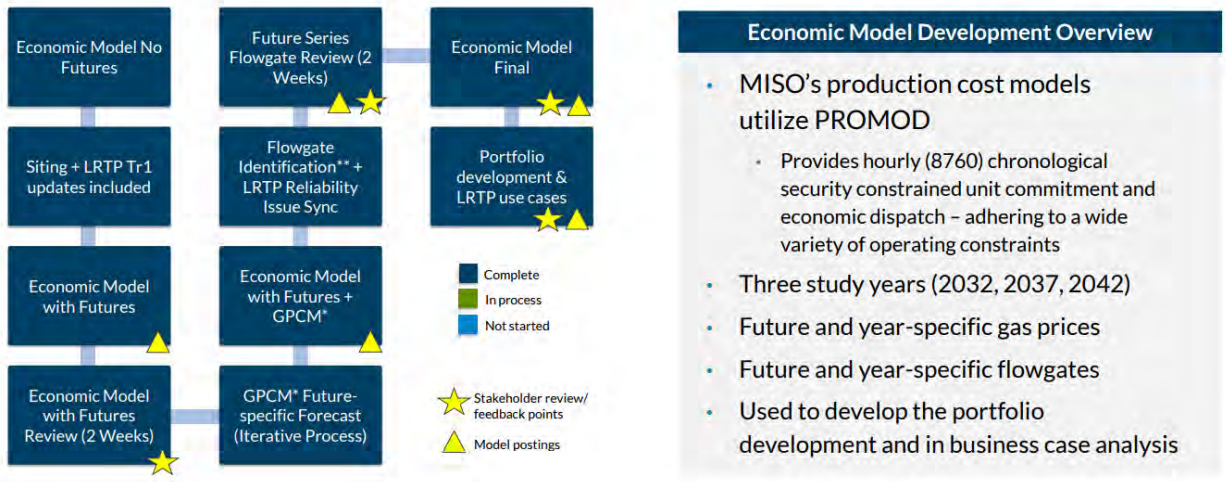


Figure 2.11: Economic Modeling 10-Step Process

Each of the economic production cost models include chronological Future- and year-specific assumptions for multiple regions to identify economic constraints and test potential solutions (See Figure 2.12: Economic Model Development Study Years).

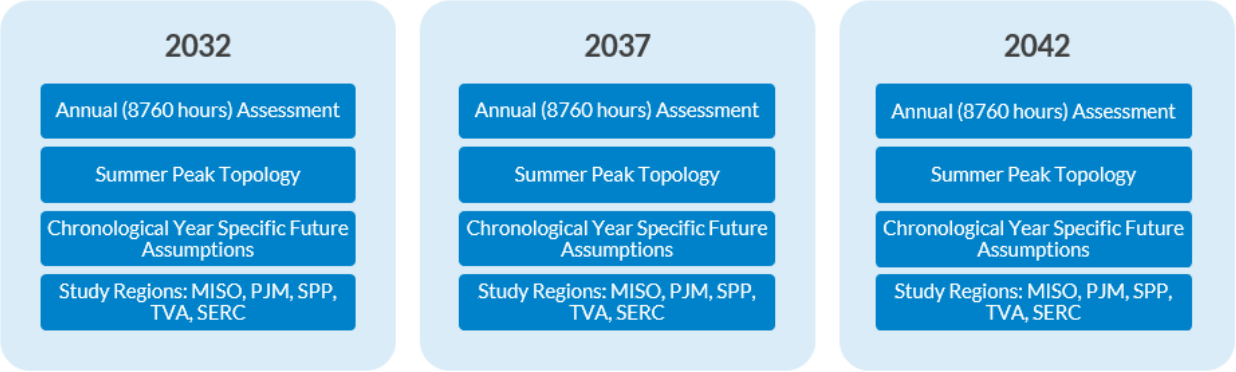


Figure 2.12: Economic Model Development Study Years

Economic Model No Futures

The Economic model building process starts with developing the base economic model without any Futures assumptions. This requires compiling Hitachi-released generation and fuel data, resource utilization data, and transmission topology for the MISO footprint and neighboring entities. The Series 1A No Futures model includes:

Base Economic Data	What's included
Hitachi PROMOD Releases	o Fall 2021 – generator updates and economic data o Spring 2022 – coal price updates o 11.5.1 engine
Neighboring Entities Data	o SPP generator additions and economic data o PJM generator additions and economic data
Resource Utilization	o Generators with signed GIA additions o Attachment Y Retirement updates
Powerflow Model	o MTEP22 - 2032 Summer Peak Powerflow model with updates o LRTP Tranche 1 Projects o 2032 Winter Peak Powerflow model ratings
Natural Gas Price	o Q2 Henry Hub 2022 natural gas prices

Table 2.2: Economic Model No Futures Inputs

Economic Model with Futures

After finalizing a set of Futures with an energy adequacy validation process, that set is fully incorporated into the economic model, resulting in the Economic Model with Futures. Once an economic model with Futures is created, the database is made available to stakeholders who have completed the necessary non-disclosure documents with MISO. As part of this process, MISO looks to stakeholders to provide feedback on transmission ratings, generator attributes, and any other discrepancies identified within the database provided. Economic Planning works with stakeholders to update model data and address potential modeling concerns as needed.

Gas Price Forecasting

The Economic model includes estimated gas prices calculated using a Gas Pipeline Competition Model (GPCM) process. The GPCM models the physical and market systems of gas pipeline networks to forecast natural gas production, pipeline and storage utilization, deliveries, and prices at different locations across the North American gas market. By completing this process after the incorporation of Futures assumptions, the gas prices reflect the impact of changing gas demand levels. The 'Economic Model with Futures' is used in an iterative process to reach convergence between gas prices and gas burns within the associated PROMOD model as seen in Figure 2.13.



Figure 2.13: GPCM iterative process

Flowgate Identification

The MISO Flowgate Identification process has been developed and refined over time through multiple MTEP economic studies. Flowgate Identification requires multiple tools, including and not limited to PROMOD and PROMOD Analysis Tool (PAT), and requires multiple iterations to identify transmission constraints to construct the PROMOD event file (See Figure 2.14: Economic Flowgate Identification Process I). PROMOD utilizes an event file as instructions on what elements to monitor and what constraints to include in a run. Due to the size and complexity of a PROMOD model, not all transmission can be included in the event file. The Flowgate Identification process produces an event file that captures likely predicted binding flowgates for the economic analysis while still allowing the PROMOD model to solve. Additional criteria for flowgate identification is detailed in Figures 2.15, 2.16 and 2.17.

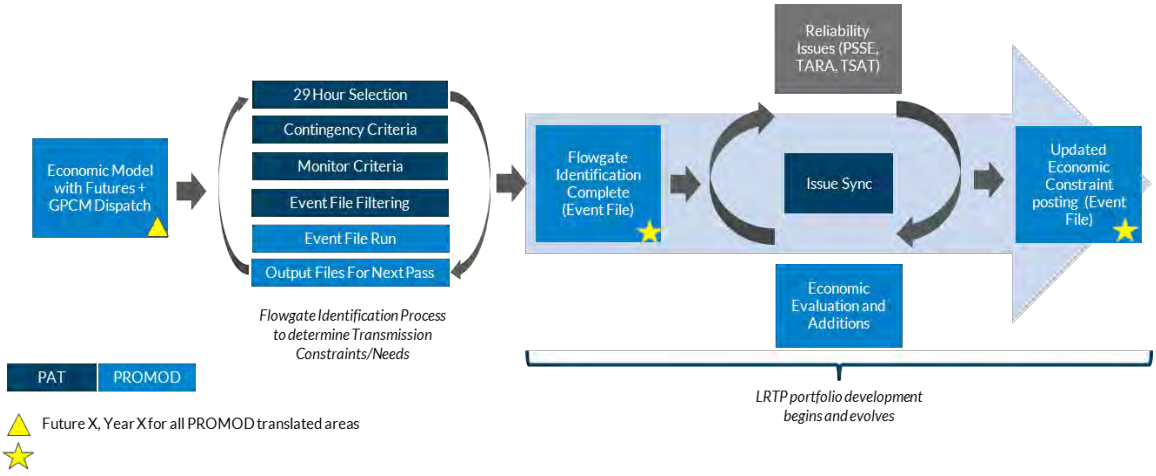


Figure 2.14: Economic Flowgate Identification Process I

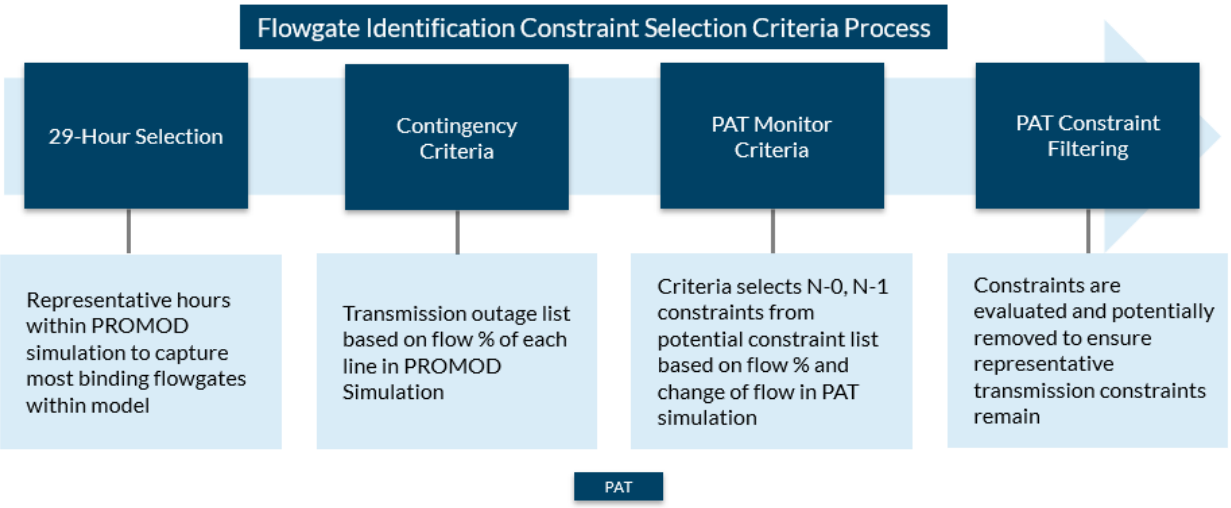


Figure 2.15: Flowgate Identification Constraint Selection Criteria Process II

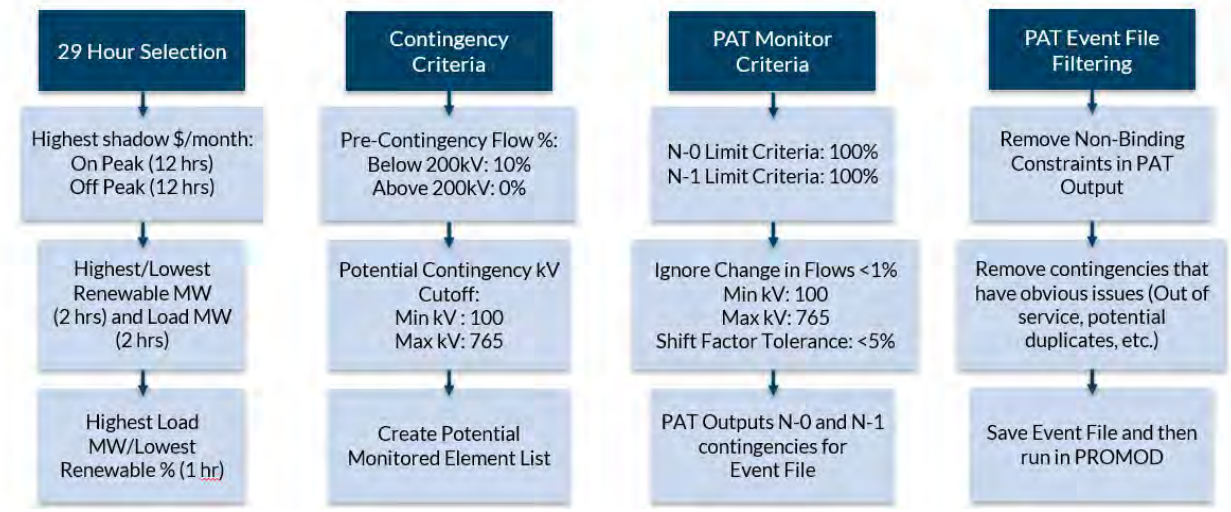


Figure 2.16: Flowgate Identification Constraint Selection Criteria Process III

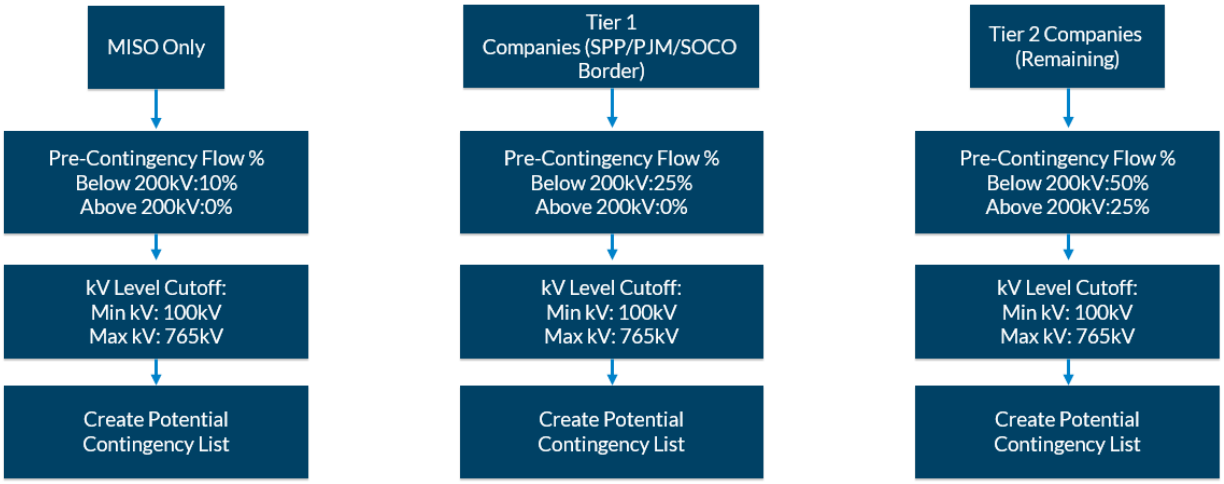


Figure 2.17: Flowgate Identification Constraint Selection Criteria Process IV

Step 3: Identify Transmission Issues

Step three involves performing reliability and economic analysis to identify transmission issues. The purpose of reliability analysis is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 2A scenario in the 10-year and 20-year time horizons. Economic analysis identifies issues like congestion, generation curtailment, widespread price separation, and price to serve load. The reliability analysis and economic analysis are iterative processes that are coordinated with each other to determine cost-effective and reliable solutions.

Tranche 2.1 work focused on resource changes contemplated by Future 2A. Key reliability and economic issues provided the foundation to develop Tranche 2.1 as a no-regrets and stand-alone first step towards the transmission required to enable Future 2A.

Economic and reliability analysis showed significant congestion across the Midwest, with widespread price separation and generation curtailment, along with significant levels of overload on lower and higher voltage equipment and decreased reactive support across the system. Also, the addition of generation located further away from load requires longer-distance transmission lines, and the lower stability limits of these lines increase stress on the system. Similar results were seen in the economic analysis with the widespread locational marginal price separation due to lack of a regional high-voltage backbone. Results also revealed opportunities to provide additional benefits by resolving energy losses from power transfers on existing transmission and by mitigating economic congestion.

Reliability Analysis

The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. It is important to understand that the Tranche 2.1 portfolio was designed to enable the grid of the future and

was not designed to resolve all identified issues. Consequently, there remain unresolved overloads, voltage violations and non-converged contingencies in the Tranche 2.1 reliability models. To the extent an issue is local and caused by a specific driver, LRTP may not resolve it. The two most common examples of local issues from specific drivers would be local generator interconnection issues and local load growth issues. If the specific siting of a Futures resource causes an issue that would not exist if the siting was relocated to a different bus within the local area, that tends to suggest that the issue is local and specific to siting of the resource, and should be addressed by the generator interconnection process if and when that specific site is pursued by an interconnection customer. Likewise for local load growth, to the extent the load growth was relocated to another bus or set of buses within the local area, if the issue persists, this suggests it might be a regional issue. If the issue is resolved or changes, this would suggest it is an issue related to load growth that the annual MTEP reliability planning process has not yet detected based on a much shorter planning horizon, and is best addressed in the future via the annual reliability planning process. As part of the MISO reliability analysis process, engineers have conducted a thorough review of the study results to ascertain if specific issues tend to be more local in nature, as described above, or more regional in nature.

Furthermore, LRTP is not a NERC compliance study, whereby every issue identified must have an appropriate mitigation measure according to NERC standards and requirements. Some issues identified in the LRTP analysis were local in nature and will be addressed in other planning processes, such as the annual MTEP reliability planning and the generator interconnection processes, as specific load and generation locations are identified. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty.

Additionally, MISO conducted transient stability analysis to determine the degree to which the proposed LRTP portfolio improved system performance related to angular stability. MISO also utilized Safe Loading Limits (SLL) calculated based on the St. Clair methodology as an additional metric to assess the improvement in overall stability and voltage performance of the system. Unlike thermal limits, safe loading limits decrease as line length increases for Extra High Voltage transmission lines; thus, safe loading limits are a good general metric to assess the overall improvement in angular stability performance.

Reliability analysis ensures the transmission system can reliably serve load under various system conditions and dispatch patterns.

- Assess transmission line loading and voltages for a wide variety of system events called “contingencies”
    - Example of a contingency: a line trips offline to clear a fault
    - At a minimum, performance is evaluated against applicable contingency events and planning criteria
    - This study included 55k single initiating events and 100k multiple contingency events

Transmission projects may be identified to:

- Ensure transmission system performance is reliable and adequate before and after contingencies occur
- Enable high regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty

Reliability analysis included several different types of simulations, each targeting different information about performance. Multiple iterations were performed to build models, identify issues and test potential solutions.

Name	Description	Timeframe	Tools
Steady-state	Determines if transmission facilities remain within safe design limits (line loading and voltage) following disturbances	• One operating point (instant) • 5+ min after a system disturbance	Powerflow (PSS/E, TARA)
Transient stability	Determines if the system will experience uncontrolled loss of load or generation following disturbances; focus on voltage and frequency performance	• 0-30 seconds following a system disturbance	Dynamics (PSS/E, DSA)
Transfer analysis	Assesses impact of various system conditions, dispatch patterns and intra-regional power transfer limits; focus on line loading and voltages	• One operating point (instant) • 5+ min after each change	Transfer analysis (PSS/E, TARA)

Table 2.3: Description of reliability study components for LRTP 2.1 study

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the four base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP single element (NERC Category P0, P1, P2, P4, P5, and P7) contingency events and selected multi-element (NERC Category P3, P6) events. Facilities in the Midwest subregion were monitored for steady state thermal loading in excess of 90% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria. For Extra High Voltage lines that are longer than 50 miles, loading levels were also assessed utilizing the Safe Loading Limit (SLL) metric.

Transfer Analysis

MISO utilized core models and built another set of models called 'transfer scenarios/models' utilizing transfer techniques to test for robust performance under varying dispatch patterns. Once the appropriate transfers (MWs flow from one area to another and/or from one fuel type to another), these new models were created and added to the set of study models. These additional 'transfer scenarios/models' can be utilized for any further analysis like the core models. The LRTP transfer study includes four transfer scenarios (20-year models) to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

MISO leverages its extensive geographic footprint and diverse resources to ensure that the system remains reliable in the future. Transfer analysis helps assess system performance, particularly concerning subregional internal import and export capabilities during high regional power transfer scenarios. These scenarios arise when geographic diversity becomes crucial in managing dispatch volatility and resource uncertainty to serve anticipated load. Generation patterns are expected to significantly shift between day and night, as well as seasonally. Therefore, the ability of load in one area to be supported by generation from a remote area will become increasingly important for ensuring ongoing system reliability.

To better evaluate the need for system flexibility, assess project effectiveness under broader assumptions, and understand the impact of locational variability in resource profiles, additional transfer scenarios were developed. MISO utilized core models and built another set of models called 'transfer scenarios/models'

utilizing transfer techniques. Once the appropriate transfers (MWs flow from one area to another and/or from one fuel type to another) are added to the core models, these new models were created and added to the set of study models. These additional 'transfer scenarios/models' can be utilized for full contingency analysis similar to the core models.

- East to West Transfer Scenario, derived from 2042 Average Model, highlights the bi-directional nature of the system with flows reversing as system conditions change. 18 GW of excess wind and solar in Local Resource Zones (LRZs) 4-7 is exported into LRZs 1-3 as they experience lower renewable output.
- Lowers to Uppers Scenario, derived from 2042 Average Model, highlights the importance of accessing resources in lower Central regions (hours where WI and MI will rely on imports). Additional excess wind from LRZs 4-6 exports into LRZ 2 (reached limit of 0.8 GW beyond the initial 4.2 GW import) and LRZ 7 (reached limit of 3.6 GW beyond the initial 5.8 GW import) as they experience lower renewable output.
- Winter Peak Low Renewable Scenario, derived from 2042 Winter Model, captures multi-day periods of low renewable output expected to occur during early morning hours and regional winter freeze. Winter low renewable scenario dispatches down solar, wind, and batteries. All conventional resources and demand response resources are dispatched to their maximum nameplate capacity. This scenario represents the lowest renewable scenario of all core models and additional scenarios with an objective to test reliance on conventional local resources to support load during winter freeze that historically occurred on MISO system.
- Twilight Summer Scenario, derived from 2042 Summer Model, captures the ability of conventional resources to meet demand during sunset. Twilight scenario dispatches down solar and wind resources to 10% of nameplate capacity. All conventional resources and demand response resources are dispatched up. Batteries are assumed unavailable since this scenario represents a multi-day low renewable scenario and batteries are not able to recharge.

Initially MISO scoped to build a fifth West to East Scenario, derived from 2042 Average Model, which highlights system limitations of output in the West. This scenario was removed from the final list as heavy West to East Bias was already present in core models and while attempting to further increase West to East flows only achieved a 2% increase in dispatch of wind nameplate percentage in LRZs 1 and 3 before voltage collapse i.e., 1.5 GW of excess wind in LRZs 1 and 3 exports into LRZs 2 and LRZs 4-7 as they experience lower renewable output.

The scope for transfer scenarios were initially presented at the LRTP workshop in August 31, 2023 and needs or issues presented at the LRTP workshop January 26, 2024. Each core model and additional transfer scenarios have supporting information such as imports/ exports from each zone with all material posted on MISO Sharefile. In addition, all results and system performance under various contingencies are posted as well.

Dynamic Assessment

With the increasing integration of renewable energy sources, dynamic assessment is essential for managing the variability and uncertainty introduced into transmission systems. This assessment evaluates how the system performs under different system conditions and dispatch patterns, ensuring that transmission networks can meet future energy demands while maintaining stability and reliability.

In the LRTP Tranche 2.1 dynamics analysis, the focus was on comparing the dynamic performance of the system with the final portfolio against a base case scenario without the portfolio. The LRTP dynamic models were constructed from the steady-state power flow models, ensuring that the topology and dispatch align with these models.

For transient stability analysis in Tranche 2.1, MISO evaluated the system's performance using the 2042 Summer Peak and 2042 Average Load core models. The 2042 average load case represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and 100% renewable penetration, meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. The 2042 summer peak model represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

MISO monitored key factors such as Transient Stability Index (TSI), first swing transient stability, angular oscillations, damping characteristics, and voltage recovery for dynamic disturbances applied to the models, comparing the performance of scenarios with and without the portfolio.

Voltage and Reactive Support

As more renewable energy sources are integrated into the grid, reactive support becomes increasingly crucial for managing their variable output and maintaining system stability. Reactive power helps keep voltage levels within acceptable limits, which is vital for the stable operation of the power system. It improves efficiency, reduces losses, and enables transmission lines to carry more power without exceeding thermal limits, effectively increasing their transfer capability.

MISO has adopted a more conservative approach during model building and criteria selection for future Inverter-Based Resources (IBR), with their reactive capabilities determined by their output i.e. +/- .95 Power Factor based on output at the time and system needs. MISO used default acceptable steady-state thermal and voltage limits, as well as post-contingency voltage deviation and transient voltage response criteria established by each Transmission Owner (TO) or Transmission Planner (TP). For issues affecting multiple TO/TP footprints, the most conservative planning criteria among the relevant TOs/TPs will apply. If a TO/TP does not specify voltage criteria, the MISO criteria outlined in Appendix K of the BPM-020 Transmission Planning Business Practice Manual will be used by default.

Economic Analysis

Economic analysis requires a market-type dispatch reflective of MISO Futures modeling and planned topology set by the MTEP powerflow model in order to evaluate potential future transmission inefficiencies. MISO's economic analysis process relies on the production cost modeling software PROMOD to identify and address economic issues caused by these inefficiencies.

PROMOD dispatches generation to meet load for every hour over the course of the year based on the constraints and assumptions included in the model. Constraints like key flowgates identified in the Flowgate Identification process, and assumptions for battery dispatch, as detailed in MISO's Series 1A Battery Modeling Whitepaper, increase the complexity of PROMOD runs and analysis.

To understand the impact of these constraints and assumptions, economic analysis occurs throughout the study process. MISO completes PROMOD runs and assesses outputs through each stage of the study process to review model accuracy, address dispatch assumptions, identify issues, and find transmission solutions. The Economic Modeling, Futures Energy Adequacy, and Alternatives Analysis sections provide details on how PROMOD was utilized in various stages of the Tranche 2.1 process. Additional critical components of the economic analysis process are detailed below.

Economic Metrics

The metrics in Table 2.4 are calculated from PROMOD outputs and used by MISO's Economic Planning team to assess the economic impact of proposed projects.

Economic Metric Name	Description	Use
Congestion Measure ($/MW)	An indication of the production cost savings opportunity from relieving transmission congestion	• Identifying most constrained transmission elements • A reduction in Congestion Measure for a constraint or group of constraints indicates a more optimal regional dispatch
Curtailment (MWh)	A measure of the total amount of energy from renewable sources which cannot be delivered economically	• Reduction of curtailment at a single generator improves that unit's financial viability • Reduction of total curtailment in a region indicates that transmission investments enable additional renewable generation
Load LMP ($/MWh)	The Locational Marginal Price (LMP) is the market price to purchase energy from a market. Load Weighted LMPs are expressed as an average price weighted by energy each hour and at each delivery point and are indicative of the price of energy in a region	• A price separation in Load LMPs across a region indicates that transmission is limiting efficient dispatch, resulting in overall higher production costs
Adjusted Production Cost (APC) ($)	A measure, by company, of the costs to serve demand, considering the effect of purchase and sales	• Evaluating the combined measure of the operating cost of companies within MISO
Adjusted Production Cost Savings ($)	APC Savings are seen when APC decreases from one model to another (i.e., Reference Case – Change Case). A company sees APC Savings when they dispatch lower cost generation, purchase power at a lower load LMP, or sell power at a higher Gen LMP	• Evaluating portfolio benefits in the Business Case
Generation Enablement (MW)	A Distribution Factor (DFAX) based methodology to determine which Future Series Model Built resources are enabled by regional transmission to connect to the system	• Future Series Model Built resources with ≥5% DFAX are considered enabled

Table 2.4: Economic Metrics

Congestion Measure

Economic congestion is assessed using "Congestion Measure" ($/MW), which is calculated by multiplying the annual Average Annual Shadow Price ($/MW/hr) of a transmission constraint by the number of annual Binding Hours (hr/yr) in which congestion at that constraint is observed. Congestion Measure approximates the annual savings for the next additional MW that could flow if that constraint was relieved. It is used as an indicator of the magnitude of economic opportunity from relieving individual transmission constraints, and when summed over all the constraints in a region, it measures whether a project or set of projects has relieved congestion in that region.

Curtailment

Curtailment is a measure of the amount of energy (MWh) which is available from non-thermal generators (generally Wind, Solar, and Hydro), but cannot be dispatched and delivered economically primarily due to two reasons: transmission constraints and/or competition between abundant renewable resources to serve load, when available resources exceed load.

A reduction in Curtailment is generally seen when transmission constraints that limit the output of non-thermal generating resources are relieved by transmission investments. Curtailment may be caused by any constraint in a PROMOD case, and not all Curtailment will be caused by transmission congestion.

Load Weighted Locational Marginal Price (Load LMP)

Price to serve load is presented using Load-weighted Locational Marginal Prices ($ / MWh) or Load LMPs. LMPs represent the marginal cost at a given location to deliver one additional MWh of energy in a given hour. A Load LMP represents the marginal cost to deliver one additional MWh of energy within a given region and over a given period of time. It is computed as the weighted average of LMPs using the hourly and locational distribution of demand energy as weighting factors.

Adjusted Production Cost

Adjusted Production Cost (APC) is a measure of the cost to serve load by company and is utilized to capture the differences in production costs between two models. This metric is used in portfolio development to identify and compare economic benefits across alternatives as well as in the Business Case to project 20-year APC savings.

Adjusted Production Cost Savings

Additional details on APC Savings can be found in MISO's Business Case Metrics Methodology Whitepaper under the section on Congestion and Fuel Savings. MISO's APC calculation methodology is described in detail the MISO APC Methodology Whitepaper.

Generation Enablement

Distribution Factor (DFAX) analysis is the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located, determining the amount of generator impact on facility loading. In this analysis, Future Series Model Built resources are considered enabled if they have a DFAX ≥5% against reliability constraints that are addressed by regional transmission.

Reliability and Economic Analysis Results

The total resource expansion for Future 2A in the Midwest subregion provided the starting point in identifying transmission issues and anticipated Tranche 2.1 solutions. Regional analysis identified key system issues under Future 2A, providing a foundation from which to develop transmission concepts into a draft portfolio. As part of the 7-step process, the economic and reliability analysis identified potential transmission issues.

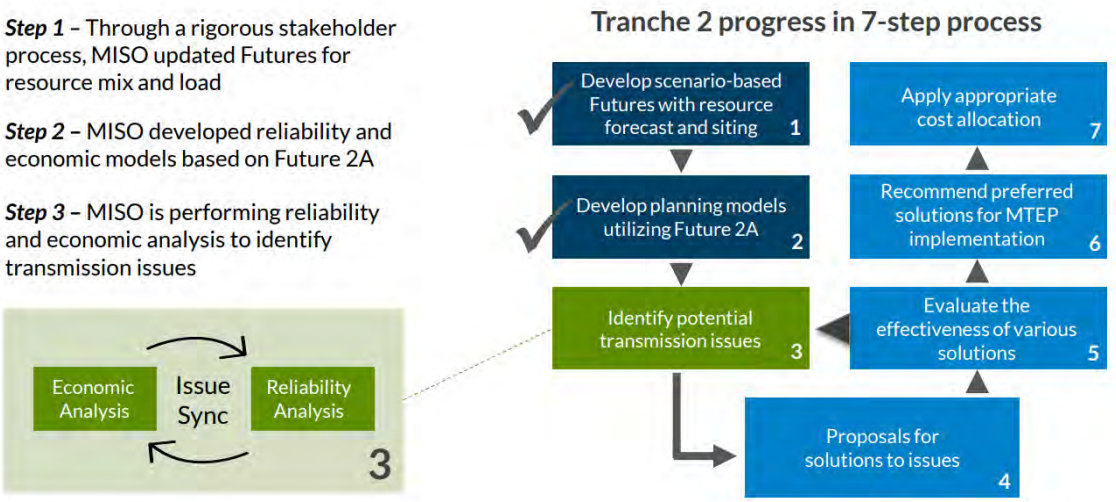


Figure 2.18: Economic and Reliability Transmission Issue Identification

The initial constraints discussed in the December 2023 LRTP workshop (economic and reliability) shaped the Tranche 2.1 portfolio. The economic analysis showed needs for MISO West, Central and East. Severe congestion was driven by high renewable penetration and load that lacked high-voltage regional transmission support to alleviate existing transmission. Similarly, the reliability analysis pointed to the need for significant transmission system enhancements. Both the economic and reliability analysis indicated significant transmission issues through the Midwest region (See Figure 2.19: Summary of Reliability and Economic Issues) and pointed to the need for a high voltage regional transmission backbone, including:

- Severe wide-area congestion across the MISO Midwest subregion
- Wide-area economic price separation between the West and East/Central regions
- Significant generation curtailment due to severe economic congestion on numerous lines
- Significant levels of overloads and voltage violations on High Voltage (HV) and Extra-High Voltage (EHV) equipment throughout the footprint
- With the changing resource fleet and decrease in reactive support, system is stressed with the expected results of lower stability limits of longer distance transmission lines
- Substantial increase in voltage angle difference between sending and receiving end as power is traveling a longer distance to reach load
- Multifold increase in system losses due to long-distance transfer and stressed transmission system

This analysis drove the development of transmission solutions for a draft portfolio.



WEST

- 20% of the facilities were found to be overloaded
- Annual curtailments exceeded 40%
- Energy losses over transmission lines increased from 2.5% to 11%

CENTRAL

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission enabled transfer of regional power
- Needs were refined through transfer sensitivities and multi-element contingencies

EAST

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission supported daily and nightly import / exports

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	66	206	28	1,000-4,000
230	41	208	17	150-4,100
<200	496	263	76	50-6,000

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	21	171	23	11-2,500
230	13	142	5	25-960
<200	158	191	53	20-2,560

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	7	113	3	60-135
<200	159	223	42	10-2,400

Figure 2.19: Summary of Reliability and Economic Issues

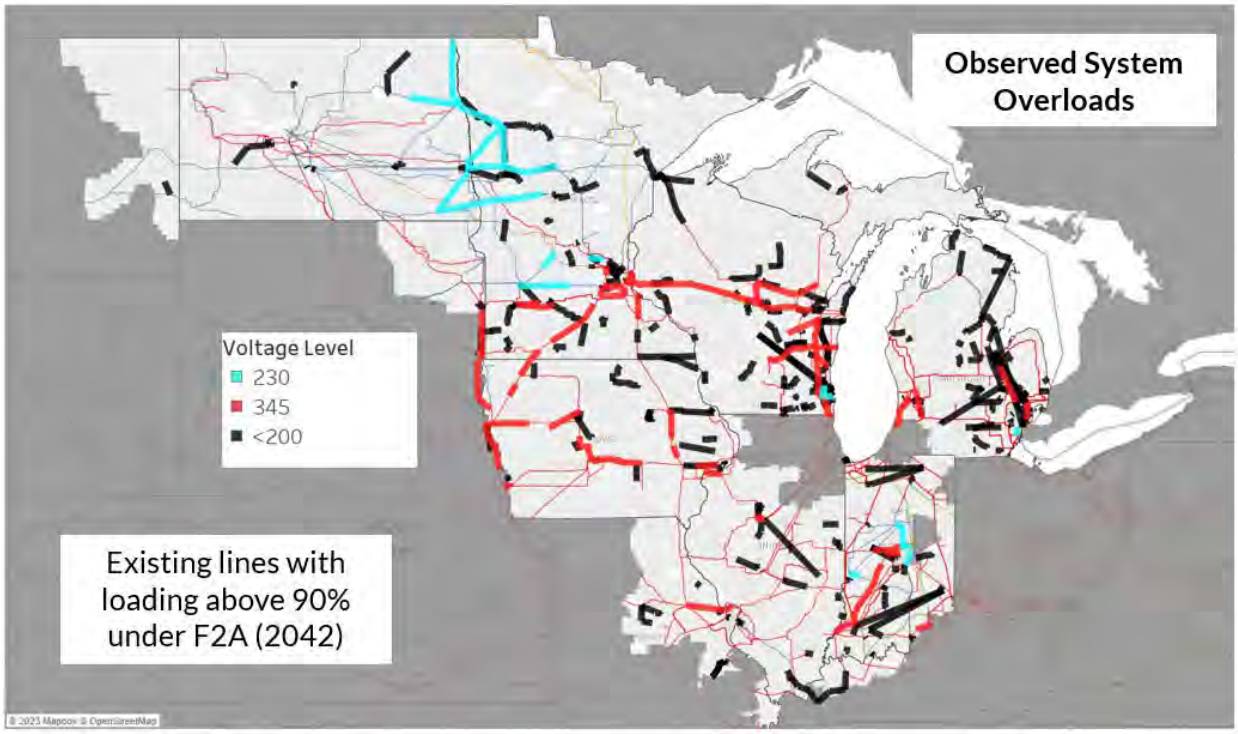


Figure 2.20: MISO Midwest subregion map showing thermal constraints observed by voltage level

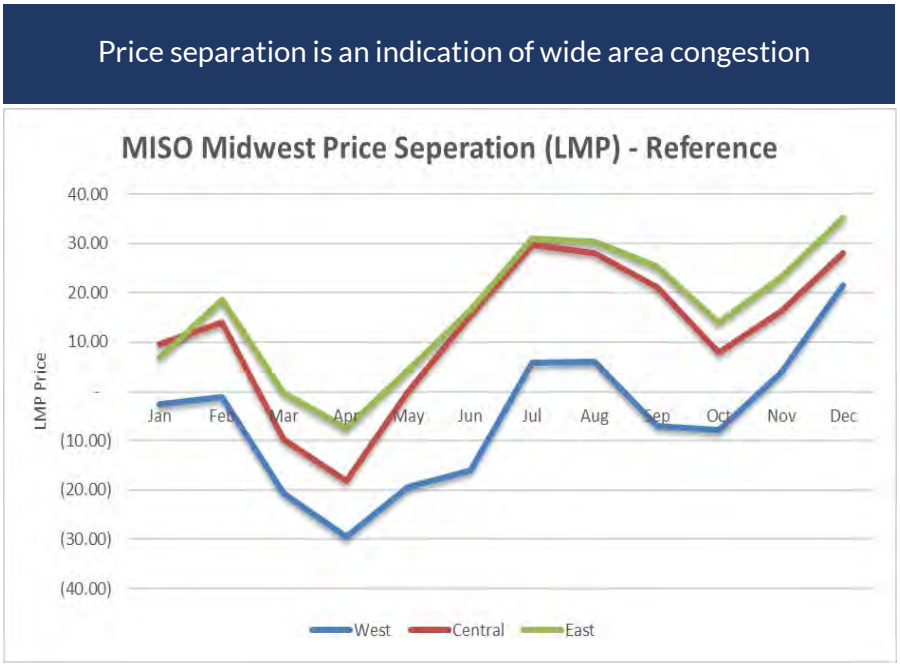


Figure 2.21: Figure 2.23: MISO Midwest Price Separation

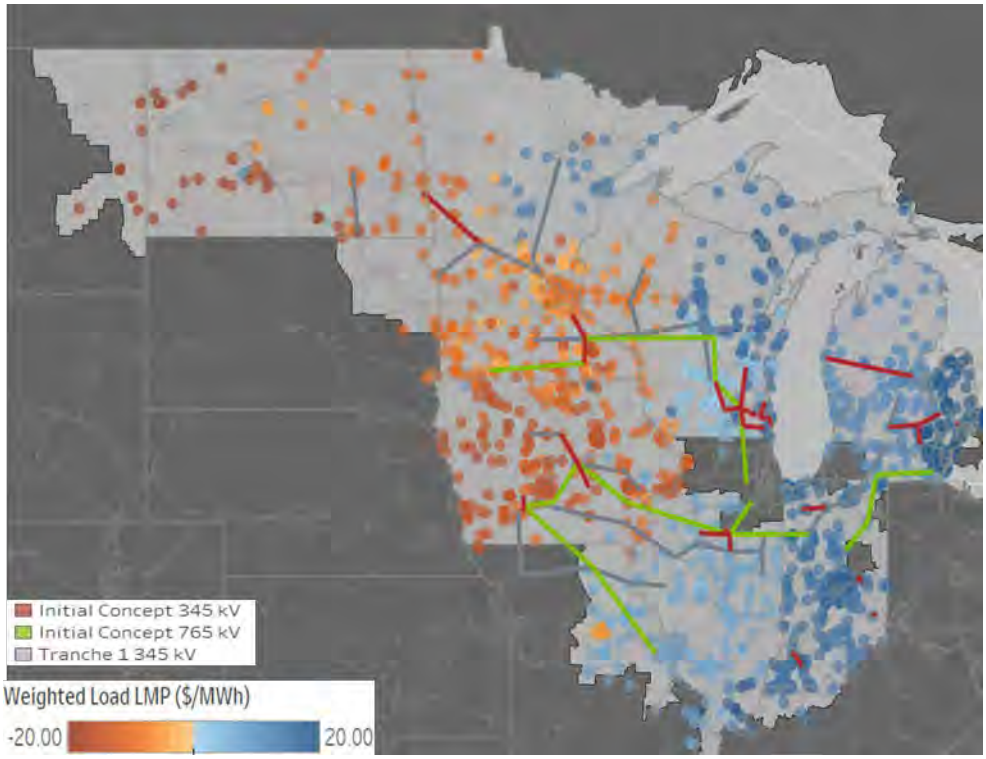


Figure 2.22: Pre-Portfolio LMP Map

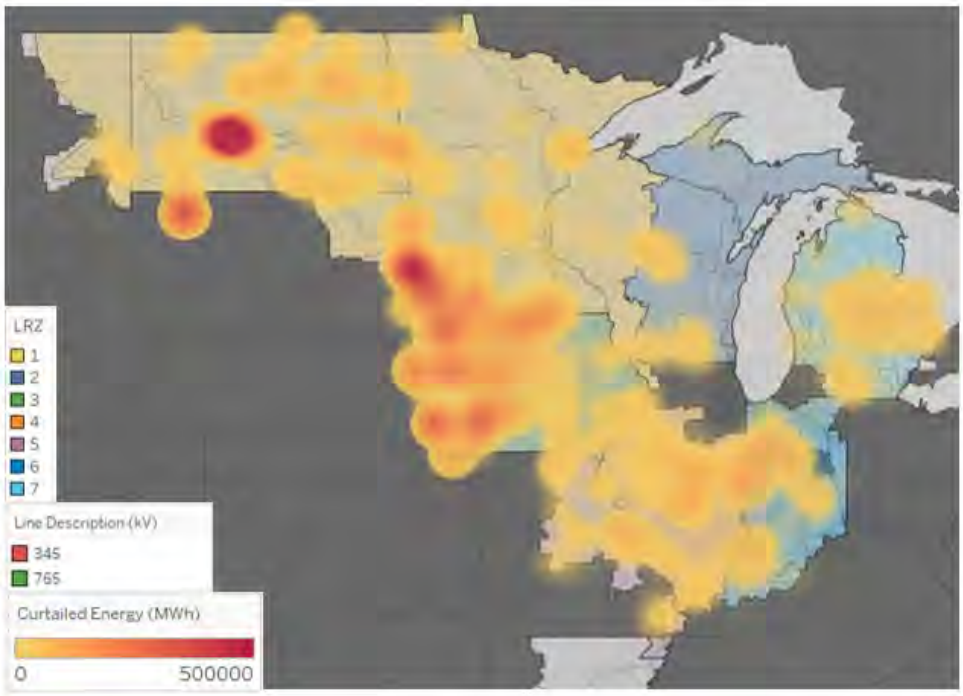


Figure 2.23: MISO Midwest Generation Curtailments Pre-Portfolio

West Region

The West region shows the need for higher voltage transmission facilities to support large power transfers and deliver generation from remote areas to load centers. MISO noted significant overloads and curtailments. Twenty percent of facilities are overloaded, curtailments exceed 15% and energy losses over transmission lines increase from 2.5% to 11%. This is also an area where line losses increase as the existing system attempts to deliver power from the Future 2A resource mix.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	66	206	28	1,000-4,000
230	41	208	17	150-4,100
<200	496	263	76	50-6,000

Table 2.5: West Region – Reliability and Economic Issues



Figure 2.24: Reference Case: Economic Congestion (West)

Central Region

Transmission in the Central region will be key to enabling system transfers and supporting high transfer scenarios between the East and West regions. In the base Future 2A power flow cases, MISO sees 10% of facilities exhibiting overloads. In addition to these overloads, MISO expects that enabling resources in the West region will increase regional transfers into and through the Central region. MISO also has seen historically that the Central region is highly impacted by different transfers and weather patterns that it needs to consider. Multi-element contingencies will also have a large impact on this region and drive additional needs.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	21	171	23	11-2,500
230	13	142	5	25-960
<200	158	191	53	20-2,560

Table 2.6: Central Region – Reliability and Economic Issues

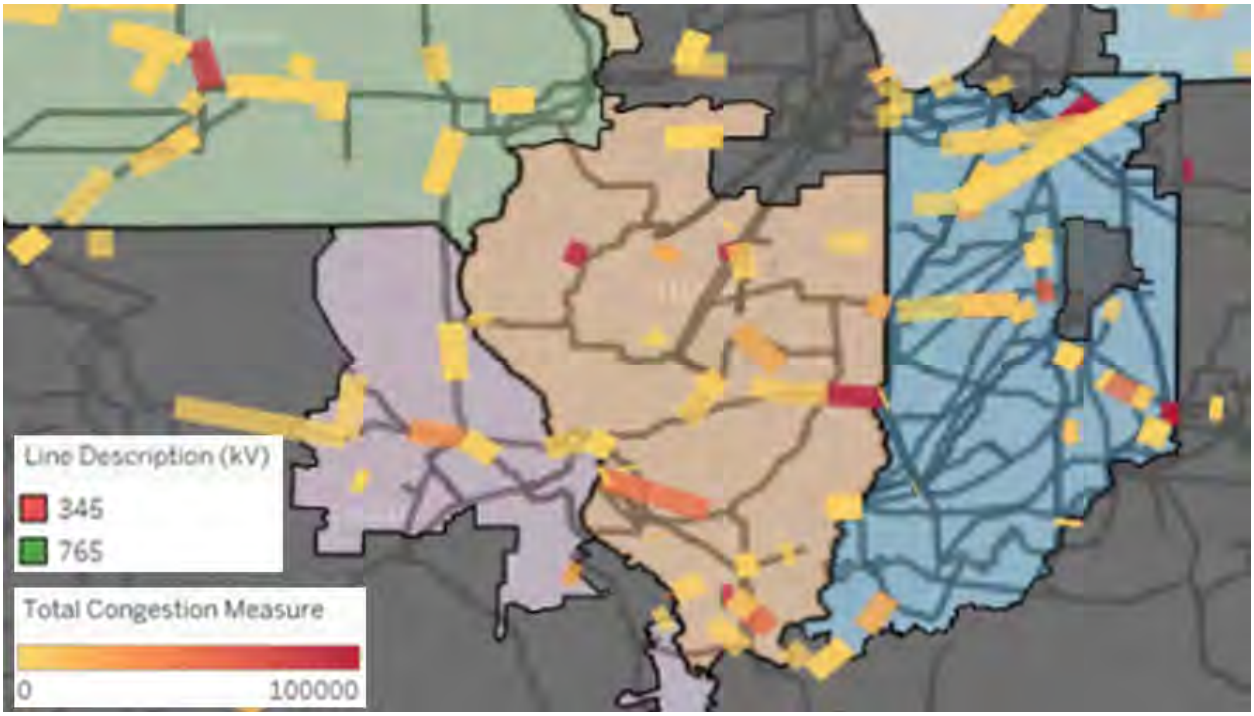


Figure 2.25: Reference Case: Economic Congestion (Central)

East Region

The East region's transmission solutions will need to consider transfer limits as changes to the resource mix create the need to enable increased imports and exports to and from the state. MISO sees more overloads (10% of facilities) and curtailment issues (annual curtailments exceed 15%), and especially the impacts of the resource fleet evolution in different import and export patterns between day and night. There is excess capacity during the day with solar resources, but imports will be needed during night hours.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	7	113	3	60-135
<200	159	223	42	10-2,400

Table 2.7: East Region – Reliability and Economic Issues

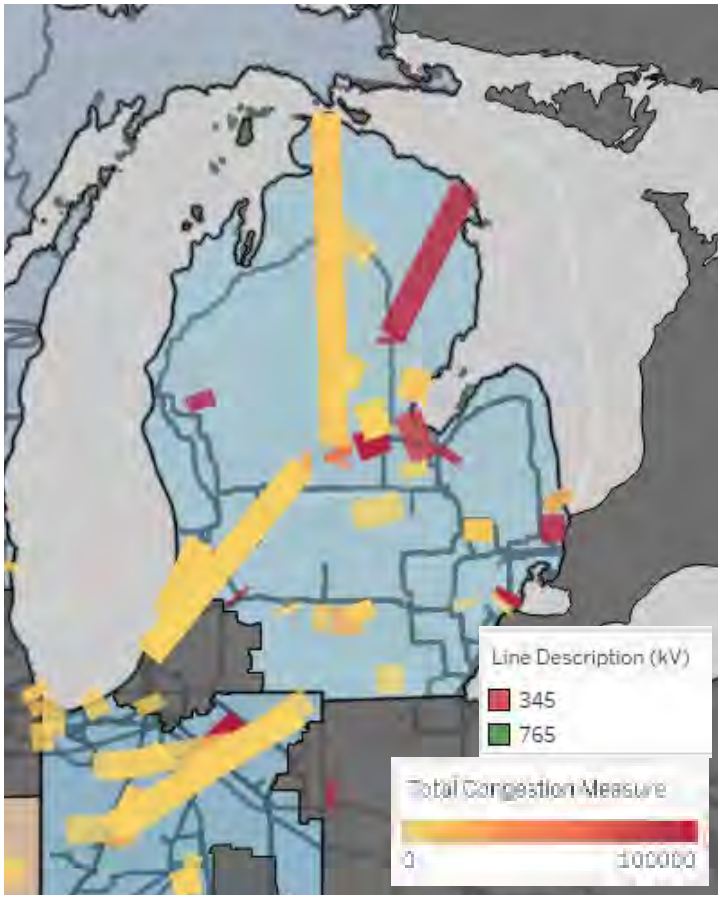


Figure 2.26: Reference Case: Economic Congestion (East)

Step 4: Propose Solutions

As MISO understood the impacts of member plans throughout the planning process, conceptual ideas were developed for what the potential transmission solutions may be. In January 2023, MISO shared a hypothetical roadmap taking concepts from its initial long-term roadmap shared in 2021. This map continued to be refined focusing on a 765 kV regional solution accounting for a future with more remote resources, and where safe loading limits and absolute limits will become more relevant. Absolute limits and Safe Loading Limits decrease as line length increases. As discussed in March PAC material (March 8, 2023), some considerations of the performance of 765 kV include:

- Transmission Limits including Safe Loading Limits and Absolute Limits,
- Cost per MW-Mile, and
- Land-Use per MW-Mile.

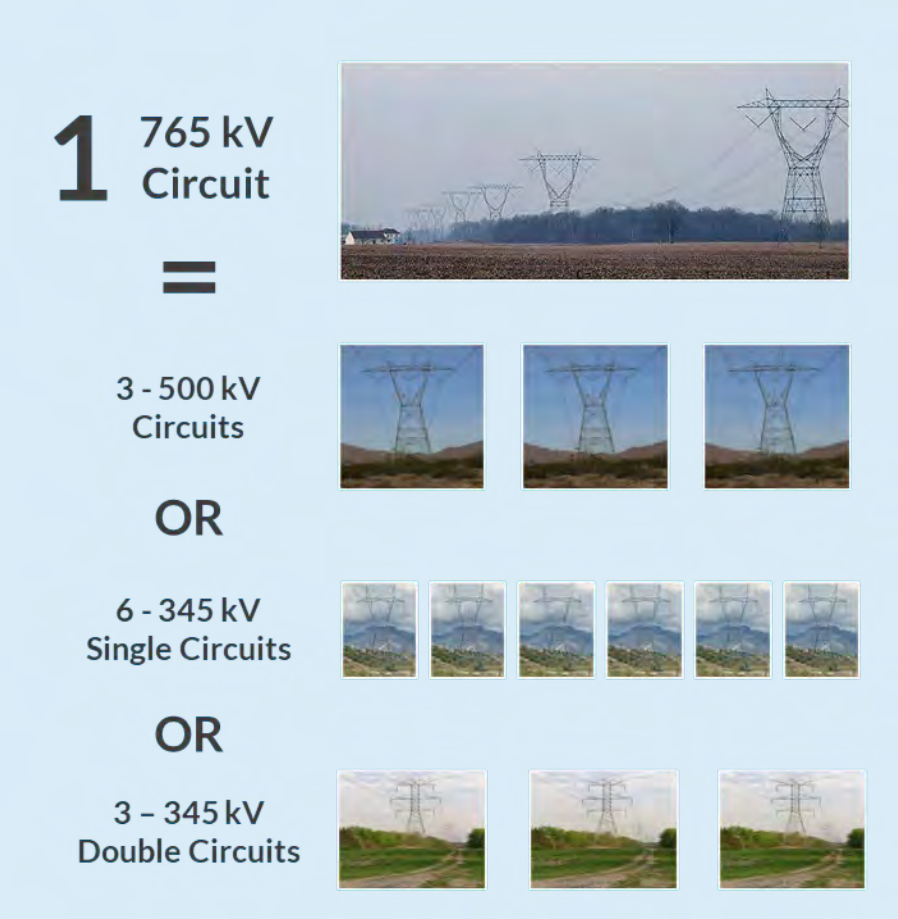


Figure 2.27: Land-Use Evaluation per Transmission Voltage

When considering the per MW-mile capability of 765 kV and 345 kV lines, 765 kV has much higher loading capability than 345 kV, particularly for longer distances. For Tranche 2.1, 50% of the proposed 765 kV facilities are more than 120 miles long. At 120 miles, the Safe Loading Limit of a 345 kV line is less than 1,000 MVA and 765 kV is 4,500 MVA. The loadings observed on the Tranche 2.1 765 kV facilities range between 2,000 and 4,000 MVA.

The cost per MW-mile of a 765 kV line is generally 33% to 50% of the cost per MW-mile of 345 kV or 500 kV lines. This implies a long distance, well utilized regional transmission system would cost much less if it incorporated a substantial amount of 765 kV transmission. Conversely, it would be much more costly to develop the required regional transmission system using only 345 kV transmission, and substantially even more cost to develop the system slowly and incrementally using sub-Extra High Voltage transmission only.

Given 345 kV is a legacy voltage, a hybrid regional solution making significant use of both 765 kV and 345 kV facilities is the optimal solution. If transmission upgrades were facilitated incrementally using 138 kV lines in place of 765 kV, the cost would be 12 to 18 times higher for 138 kV incremental transmission upgrades than it would be for 765 kV on a cost per MW-mile basis.

In addition to lower cost, a 765 kV line requires less land-use on a per MW-mile basis than 500 kV or 345 kV. The land use in acres per MW-mile required for 765 kV is less than 25% to 67% of the land use required in acres per MW-mile for the equivalent 345 kV alternative, and about 33% of the land use required in acres per mile for 500 KV.



Figure 2.28: Progress of Portfolio Development

Refining Solutions

Robustness Testing

A key objective of robustness testing is to identify key projects that were either approved or in the process of approval subsequent to the finalization of LRTP power flow models in October 2023, which may have a material impact on the anticipated Tranche 2 portfolio. The second main objective is to perform an assessment with and without key projects and identify areas that may result in MISO modifying, adding to, or removing transmission facilities in the LRTP portfolio.

- **Removals:** Tranche 2 projects or segments may be considered for removal and replacement by key projects. Evaluate areas where the reliability impact provided by key projects and Tranche 2.1 projects overlap or duplicate independently.
- **Modifications:** Tranche 2.1 projects or segments may be considered for modifications. Evaluate areas whether issues addressed by key projects and Tranche 2.1 projects are closely related and if modifying Tranche 2.1 transmission facilities could optimize the reliability impact of both.

- **Additions:** Consider potential adverse effects on the system resulting from the inclusion of key projects, while also considering constraints that may be local in nature that are better resolved in annual MTEP reliability planning and the generator interconnection processes.

If initial robustness testing results in a reliability impact such as need for removal, modification or addition, then further testing may be conducted utilizing some or all of the remaining core reliability cases and additional transfer scenarios that represent various system conditions and dispatch patterns to better understand the impacts of all projects and system changes.

Key Projects

Tranche 2 robustness testing refers to a process for reviewing the impact of system changes, specifically key projects, that were either approved or under consideration following the completion of LRTP power flow models in October 2023 which may affect the anticipated Tranche 2 portfolio. Each key project that is identified for robustness testing is analyzed in detail by looking at the relevant system conditions and contingencies with and without key projects. Performance of projects, effectiveness in resolving identified needs, or any new criteria violations is documented during the testing process.

MISO completed an assessment on the impact of select MTEP23 and MTEP24 projects, the JTIQ projects, and the Grain Belt Express (GBX) Merchant High Voltage Direct Current project. The MISO-SPP Joint Targeted Interconnection Queue Projects facilitate the integration of new resources by optimizing the transmission infrastructure required across regional boundaries. The JTIQ and Tranche 2.1 projects, being electrically close, complement each other. JTIQ projects do not negate the need for the Tranche 2.1 portfolio. The GBX project does not prompt any required modifications to the Tranche 2.1 portfolio located within its solution area. There is a noticeable reduction in overloads and lines loadings on monitored flowgates with addition of the Tranche 2.1 portfolio.

Eligible projects

In Tranche 2, the powerflow core models were built from the MTEP22 topology (including LRTP Tranche 1 approved projects) with load, generation, and siting information from Future 2A. After much collaboration and engagement with stakeholders, powerflow models were finalized in October 2023. These models used best-known information at the time of completion. Key projects were selected from the following categories for robustness testing:

- MTEP23 portfolio of projects approved by MISO's Board in December 2023
- The Transmission Connection Agreement (TCA) for the GBX Merchant HVDC project was accepted by FERC in February 2024
- JTIQ projects, subject to FERC approval and MISO Board approval
- MTEP24 portfolio of projects to be approved by MISO's Board in December 2024

Generally, projects on the 230 kV system and above that are electrically close to identified issues and transmission facilities shown on the March 4th portfolio map would qualify to be tested. It is important to highlight that if any of the key projects from MTEP23, MTEP24, JTIQ, or Grain Belt Express have a material impact on the anticipated Tranche 2.1 portfolio, that impact will be detected in the robustness testing. Based on the criteria described above, MISO identified several projects for Tranche 2.1 robustness testing, listed below:

Key projects eligible for robustness testing	Category	PSSE Area Number[2]
P23026 – New South-Central Illinois Transmission Expansion	MTEP23	357, 361
P50106 – Big Cedar Interconnection	MTEP24	627, 635
Bison – Hankinson – Big Stone South 345	JTIQ	600, 608, 613, 615, 620, 627, 633, 635, 661
Lyon Co. – Lakefield 345		
Raun – S3452 345 kV		
Auburn – Hoyt 345 kV		
Grain Belt Express with projects as identified in Transmission Construction Agreement	MHVDC	356, 357, 330, 333

Table 2.8: Summary of Key projects eligible for robustness testing

MISO's initial screening used the LRTP 20-year out average load model, developed for Tranche 2.1 reliability assessment with Future 2A assumptions. Models are described in detail in the Reliability Study Whitepaper.

The 2042 LRTP Average Load Case represents typical system conditions within 70-80% on the load duration curve. This scenario is the most stressed case because it has 100% renewable penetration, meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. To better assess the impact of key projects, MISO ran all single initiating events, i.e., contingencies, on the following four scenarios first, then supplemented results with two additional scenarios incorporating the outcome of the alternative analysis (Key projects shared at the May 13, 2024 LRTP workshop and additional study material is posted on MISO Sharefile:

Models with March 2024 Initial Proposed Portfolio Results:

1. The 2042 LRTP Average load case (i.e., most stressed LRTP case)
2. The 2042 LRTP Average load case + LRTP T2.1 anticipated portfolio of projects
3. The 2042 LRTP Average load case + key projects
4. The 2042 LRTP Average load case + key projects1 + LRTP T2.1 anticipated portfolio

Models with May 2024 Near-Final Proposed Portfolio Results:

1. The 2042 LRTP T2.1 Average load case with Alternatives Portfolio
2. The 2042 LRTP T2.1 Average load case with Alternatives Portfolio + key projects

At a high level, the process diagram below best illustrates robustness testing. The diagram refers to the models used for robustness testing and key projects were presented in May.

[2] Key projects are electrically far away from each other and grouped by location (PSSE Areas #) to focus more closely on their impact.

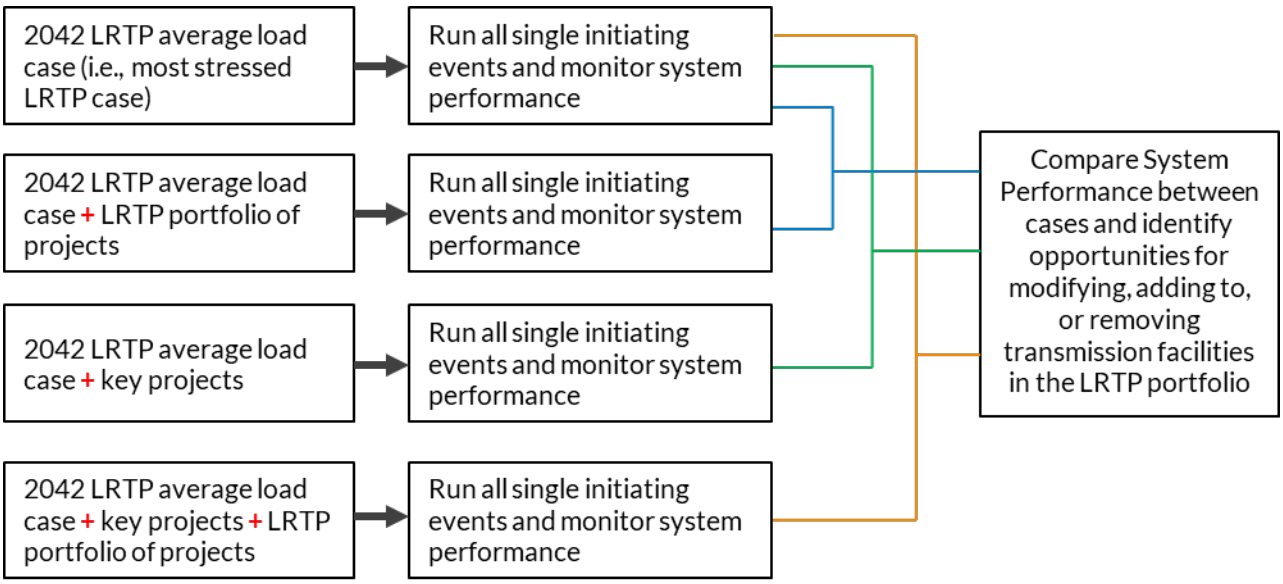


Figure 2.29: Models used in robustness testing

To gauge the impact of key projects more accurately, MISO first evaluated all single-initiating events using four scenarios from the March 2024 Initial Proposed Portfolio. Then this analysis was enhanced by incorporating two additional scenarios featuring alternative projects from the May 2024 Near-Final Proposed Portfolio. Key projects were shared at the May 13, 2024, LRTP workshop.

Project P23026: New South-Central Illinois Transmission Expansion and Project P50106: Big Cedar Interconnection:

Robustness testing assessment reinforces the projects' alignment with local needs, consistent with their MTEP justification. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. More information about the projects, local needs and robustness evaluation can be found at the June 10, 2024, LTRP workshop.

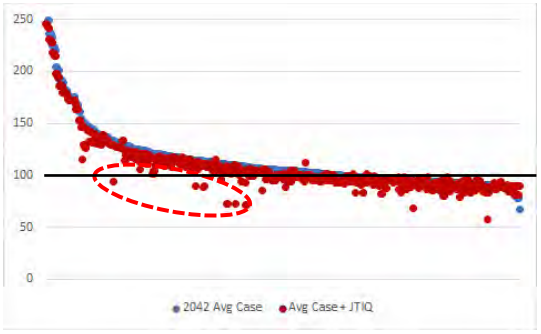
JTIQ Projects

The MISO-SPP Joint Targeted Interconnection Queue Projects enable interconnection of new resources by optimizing transmission needed for interconnection across the seams. JTIQ projects have a positive impact on reducing overloads and loadings on monitored flowgates; consistent performance was observed with the March and May portfolios. JTIQ and LRTP Projects are electrically close, serving to complement rather than compete with one another. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification of projects required due to a very limited reach.

Models with May 2024 Near-Final Proposed Portfolio Results

Out of about 700 monitored flowgates, only a handful (highlighted in red circles in Figure 2.30) were considered for modification. The positive impact of JTIQ on monitored flowgates is noteworthy, yet it doesn't possess the comprehensive scope and robustness needed to entirely substitute or modify sections within the LRTP portfolio. There's a clear synergy among multiple local flowgates; JTIQ and LRTP portfolio

combined resolved non-converged events, enabled transfer of power, and bolstered the overall system strength.



- Flowgate loading in the Avg Case with and without JTIQ
- Red demonstrates JTIQ reduces loadings on some monitored flowgates versus the Avg Case without JTIQ



- Flowgate loading in the Avg Case with and without JTIQ + near-final proposed portfolio
- Orange demonstrates JTIQ and near-final proposed portfolio complements each other, further reducing flowgate loading

Figure 2.30: Flowgate loading in the Average Case with and without JTIQ vs Flowgate loading in the Average Case with and without JTIQ + near-final proposed portfolio

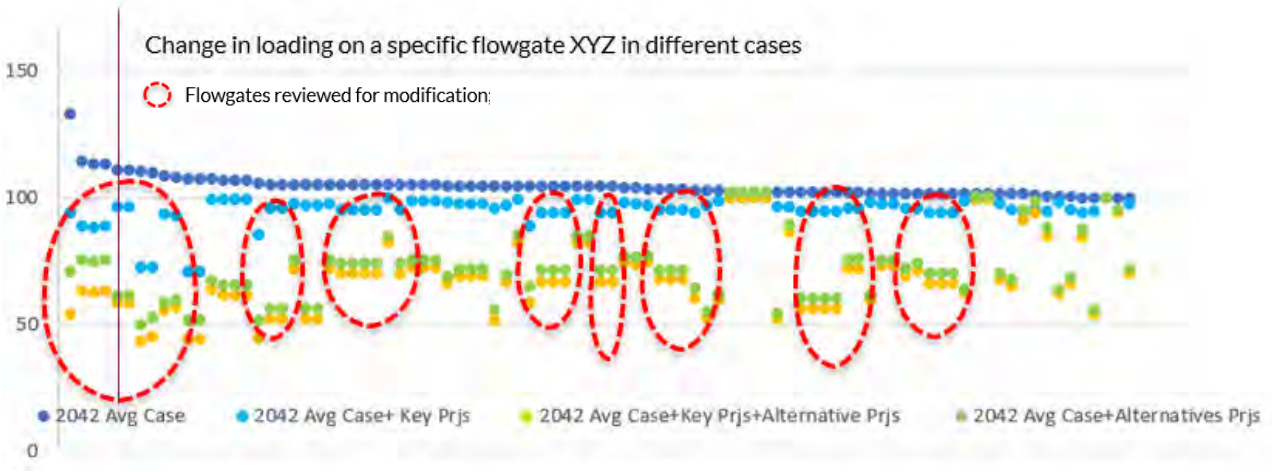


Figure 2.31: Flowgates considered for modification

Grain Belt Express (GBX)

Merchant HVDC Transmission Line with projects as identified in Transmission Connection Agreement (TCA). MISO appropriately modeled key transmission projects eligible for robustness testing to ensure a least-regrets, robust portfolio.

- Transmission line(s) modeled with appropriate characteristics.
- Grain Belt Express (GBX) modeled as a single 1.5 GW generator injection at the MISO Point of Interconnection (POI) and a single 1.0 GW generator injection at the AECI POI.

- Modeled MISO network upgrades associated with the injection.

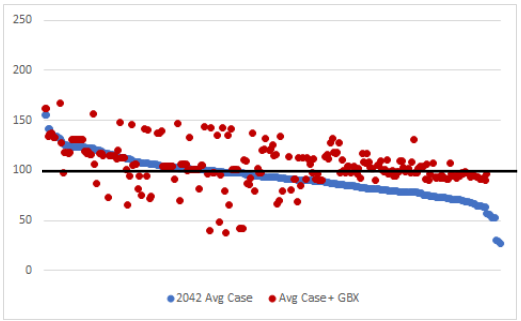
- Dispatch:
  - Injection of 1.5 GW (GBX) into the MISO system was balanced with renewables across MISO Midwest system scaled down to balance load/losses with generation.
  - Injection of 1.0 GW (GBX) into the AECI system was balanced with output reduced by 1.0 GW from the oldest coal units.

All Network Upgrades identified in the Transmission Connection Agreement (TCA) were added (Click here for a detailed list of all connection facilities and necessary upgrades specified in the TCA):

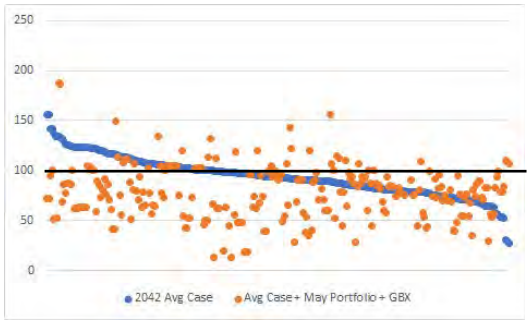
- New Burns-Montgomery 345 kV lines (2X)
- Rebuild Big Creek-Warrenton 161 kV line
- Rebuild Belle Tap Gasco Tap 138 kV line
- Rebuild Belle Tap-Meta Tap 138 kV line
- Rebuild Bland- Gasco Tap 138 kV line
- Rebuild Miller-Meta Tap 138 kV line
- Rebuild Warrenton-Montgomery-3 161 kV line

Models with May 2024 Near-Final Proposed Portfolio Results

Grain Belt Express (GBX) 1.5 GW injection further stressed the system; GBX 1.5 GW injection performance with the May portfolio still closely mirrors the March portfolio, no Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. The near-final Tranche 2.1 projects strengthen the system and have a positive impact on reducing overloads and loadings on monitored flowgates.



- Flowgate loading in the Avg Case with and without GBX
- Red demonstrates GBX increases loadings on some monitored flowgates and reduces loadings on others versus the Avg Case without GBX



- Flowgate loading in the Avg Case with and without GBX + near-final proposed portfolio
- Orange demonstrates GBX + near-final proposed portfolio reduces stress for some flowgates

Figure 2.32: Flowgate loading in the Average Case with and without GBX vs Flowgate loading in the Average Case with and without GBX + near-final proposed portfolio

The near-final Tranche 2.1 proposed portfolio posted in May significantly reduces overloads/loadings on monitored flowgates when compared to the 2042 Avg Case + GBX without the near-final proposed portfolio demonstrating enhanced reliability for the MISO Midwest subregion, enabling member plans for fleet transition, load growth and regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty.

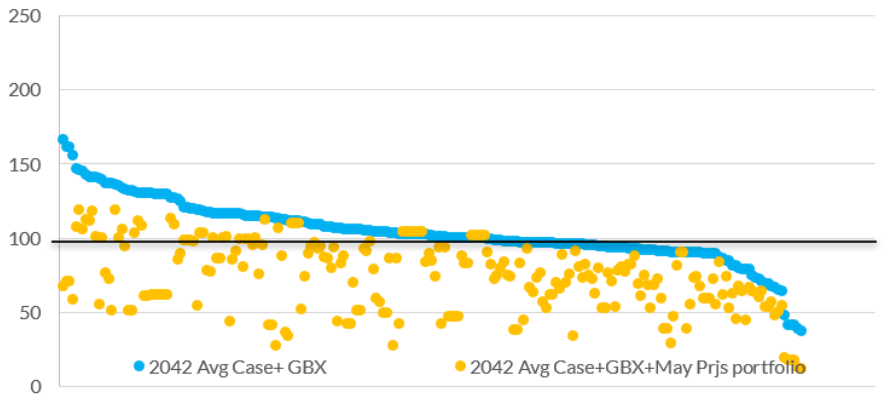


Figure 2.33: Flowgate loading in the Average Case with GBX vs. Flowgate loading in the Average Case with GBX + near-final proposed portfolio

Alternatives Analysis

Analysis of alternatives was performed and 97 projects representing 47 solutions were received from stakeholders. Not all these solutions were evaluated as MISO focused on alternatives that are more closely aligned with the same issues and needs that drove the solutions for this portfolio, various alternatives were similar in location and ones that are likely to be constructed in a timely manner. Additionally, some solutions were evaluated along with variations of alternatives developed by MISO staff, and some projects addressed more local versus regional needs and are more suited for the annual MTEP reliability planning and the generator interconnection processes. **Based on alternative analysis, MISO made additions to the portfolio in MN, IA, IN, ND, SD, MI and replacement in MO.**

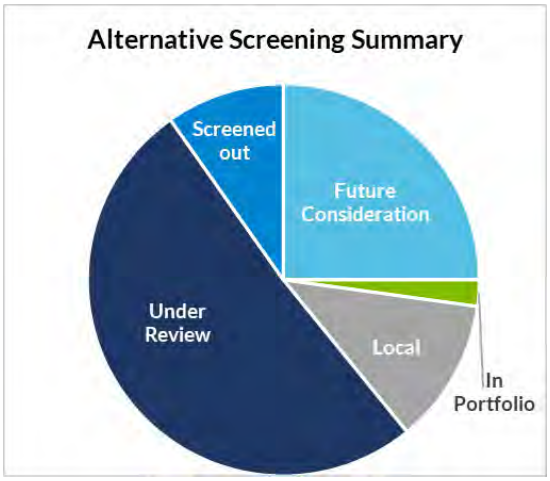


Figure 2.34: Alternative Screening Summary

Process

Alternative solutions were reviewed within key considerations.

- Does it align with the initial portfolio?
- Does it contribute to the objectives of Tranche 2.1?
- Is it focused on regional needs considering historic and new transfer patterns across the Midwest?
- Does it contribute to resolving and/or further mitigating identified issues in the subregion or region?
- Does it cause other potential issues?

Additionally, the following decision factors also guided analysis:

- If an alternative solution was identical or close to solutions already in the initial concept, there was no need to test the alternative solution. However, minor adjustments could be considered as appropriate.
- If an alternative solution was additive to the initial concept, MISO could recommend the project be resubmitted as an alternative in a future planning process.
- MISO could create a new alternative by combining components of one or more alternatives, and potentially combine them with initial solution concepts.
- Some alternative solutions could be screened out for several qualitative reasons, such as alignment with overall objectives and concept, constructability, permitting risk, local rather than regional focus, and other various reasons.

Of the 97 alternative solutions submitted, 47 passed the threshold for analysis.

- 97 alternative solutions were submitted by 32 entities
    - 21 Transmission Owners
    - 8 Transmission Developers
    - 3 Transmission Dependent Utilities
- Most included multiple facilities
- Alternatives recommended replacements and additions
- There were common facilities among multiple solutions

Analysis Decisions for Alternatives

- Under Review: Alternative or variations will be considered for Tranche 2.1
- Future Consideration: May be considered as possible solutions in future planning initiatives including, but not limited to, future LRTP initiatives

- In Portfolio: Represent proposed facilities already included in the March Tranche 2.1 initial proposed portfolio
- Local: Mainly resolving local issues
- Screened Out: Will not be considered in the current Tranche 2.1 based on initial screening

Alternative Analysis Results

MISO grouped the 47 alternatives into six studies for engineering analysis to understand system performance. Reliability analysis focused on the alternative performance compared to the March 4, 2024, draft portfolio (presented at March 15, 2024, LRTP workshop) with supplemental information from the base model (without portfolio) and transfer scenarios. Economic analysis focused on the alternative compared to the March 4th draft portfolio and reference case model (without portfolio). Details were provided via Sharefile.

No.	Alternative Description	Location	Recommendation
1	Maple River – Cuyuna 345	ND/MN	Add to portfolio
1	Big Stone South – Brookings – Lakefield 765	SD/MN	Add to portfolio
1	Lakefield – East Adair 765	MN/IA	Add to portfolio
1	Reynolds – Sullivan 765	IN	Do not add to portfolio
2	Denver – Nelson Road 345	MI	Add to portfolio
2	Goss – Sabine 345 ***Replaces: Oneida – Sabine Lake 345***	MI	Do not add to portfolio
3	Brookings – Chisago Co. – Highway 22 – Paddock – Plano 765 ***Replaces: Lakefield – Pleasant Valley – North Rochester - Jefferson Co – Plano 765***	SD/MN/ WI/IL	Do not replace project in portfolio, keep original
4	Milan – Sumpter 345	MI	Do not add to portfolio
4	Duff – Culley – Reid 345, AB Brown 2nd XF, Culley 2 XFs	IN/KY	Add to portfolio
4	Iron Range – St. Louis – Arrowhead 345	MN	Add to portfolio
4	Big Stone S – Hazel Creek – Blue Creek 345	SD/MN	Do not add to portfolio
5	Montgomery – Sioux – Stallings 345, Kingdom – Bland – Labadie 345	MO/IL	Do not add to portfolio
5	St. John – Burr Oak 345	IN	Do not add to portfolio
5	Lehigh – Twinkle 345	IA	Add to portfolio
6	Maywood – Belleau – MRPD- Sioux, MRPD – Bugle - Roxford/Gateway) 345 + XFs ***Replaces: East Adair –Timber Branch – Labadie 765***	MO/IL	Replace project in portfolio

Table 2.9: Project grouping for alternative analysis

Alternative 1 - New 765kV from South Dakota through Minnesota into Iowa and North Dakota 345kV outlet into Northern Minnesota and evaluation of southern Indiana 765 kV

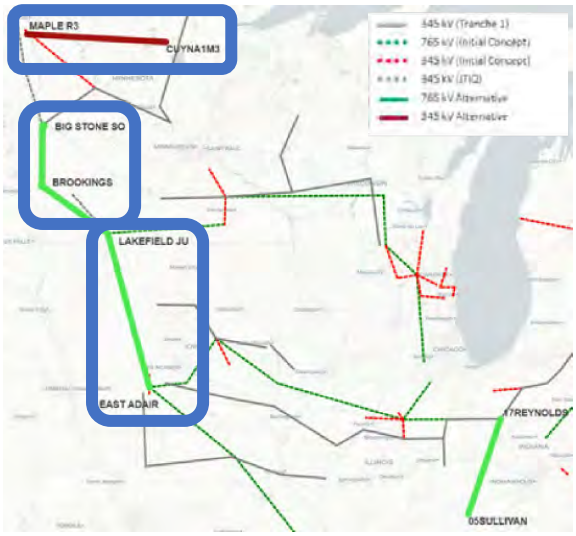


Figure 2.35: Map shows selected Alternative 1 projects in blue boxes

Alternative 1 adds four projects to the portfolio and unlocks generation in the West as a complement to existing and 765 kV paths in the initial draft portfolio.

- 3 project proposals to add in MN/SD/ND/IA
    - Maple River – Cuyuna 345
    - Big Stone South – Brookings County –Lakefield Junction 765
    - Lakefield – East Adair 765
- 1 project proposal to add in IN
    - Reynolds – Sullivan 765
- No projects from initial portfolio replaced or removed

Alternative 1 facilitates Future 2A fleet change by increasing the deliverability of renewable energy and providing more production cost savings for the MISO Midwest.

- 765 kV from South Dakota through Minnesota into Iowa increased delivered energy from North Dakota, South Dakota, Minnesota, Iowa and is added to the portfolio.
- 765 kV from Lakefield to Adair completed a redundant loop configuration for the 765 kV projects, allowing greater reliable use of other portions of the proposed 765 kV system and is added to the portfolio.
- 345 kV from North Dakota to Minnesota improved North Dakota exports and is added to the portfolio.

- Reynolds – Sullivan 765 did not result in significant congestion relief without additional support and therefore was not selected to be added to the portfolio.

Maple River – Cuyuna 345; Big Stone South – Brookings – Lakefield 765; Lakefield – East Adair 765

Overall, Alternative 1 curtails approximately 7.5 GWh less renewable energy than the Initial draft portfolio, reduces congestion on Iowa flowgates, improves North Dakota exports, and facilitates a more economical dispatch for MISO Midwest resulting in higher Adjusted Production Cost Saving over the initial portfolio. The projects resolve reliability constraints and reduce loading stress across all reliability models. Negative percentage indicates a decrease in curtailments.

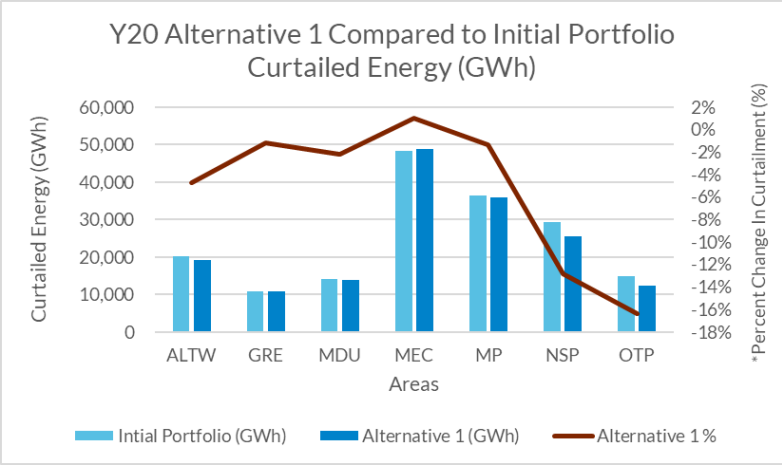


Figure 2.36: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1

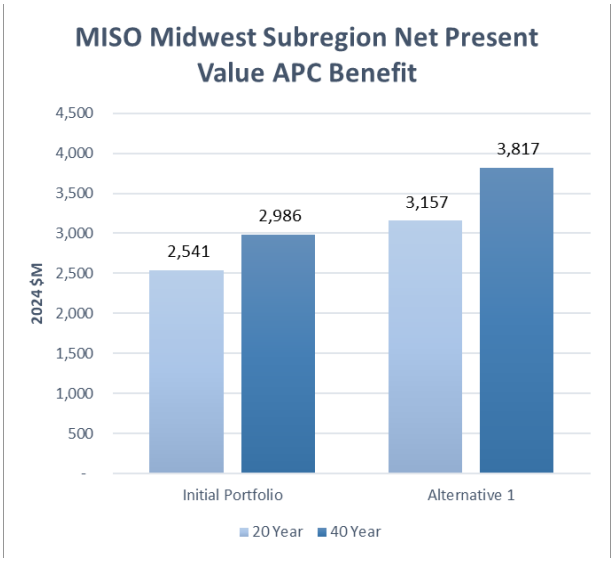


Figure 2.37: Midwest Subregion Net Present Value APC Benefit

Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Results based on analysis performed during portfolio definition. Results are not inclusive of all portfolio value and final results are expanded on by the business case analysis.

The new 765 kV from South Dakota through Minnesota into Iowa and North Dakota 345 kV outlet into Northern Minnesota unlock additional economic value by reducing renewable curtailment. The 765 kV extension into South Dakota provides greater transmission capacity and a direct regional outlet for strong wind resources in that area.

The 765 kV connection between Lakefield Junction and East Adair creates a redundant 765 kV loop between Minnesota, Wisconsin, Iowa, and Illinois, which allows the other portions of that loop to be reliably used at higher capacities. This increases the overall capacity of the 765 kV network to deliver renewable resources across the region. The redundant configuration is more successful at relieving congestion both near Lakefield Junction where the 765 kV station functions as an on-ramp for resources, and across central Wisconsin which would otherwise be sensitive to contingency flows for the loss of the 765 kV corridor between Rochester MN and Southern Wisconsin.

The 345 kV segment in Northern Minnesota improves the system's ability to move renewable resources from Western Minnesota and North Dakota towards load centers in Northern Minnesota and provides congestion relief for the line with the greatest Reference case Congestion Measure in Northern Minnesota.

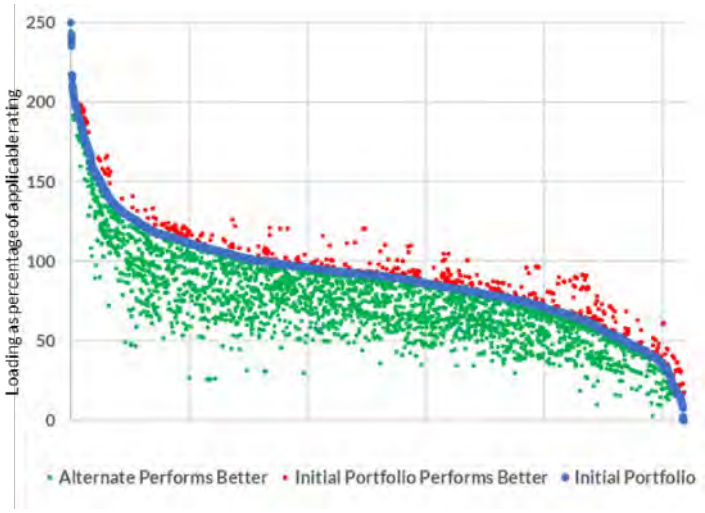


Figure 2.38: Scatter plot showing Alternative 1 performance as compared to Initial Portfolio

Each dot on this plot shows loadings observed from alternative projects for each monitor elements and contingency pair for all core models. Loadings observed in initial portfolio models are used as reference in blue font (blue dots make a smooth line as loadings are sorted in descending order). Loadings observed from alternative projects are shown in red (harming) and green (helping) fonts. More green dots suggest that alternative is helping in reducing the loading stress in the region, whereas redder means that alternative increased loading stress on the system. Blue line overlapping red and green dots means that alternative has little or no impact.

Additional data is provided in the May 29, 2024, LRTP workshop demonstrating other impactful considerations from alternative analysis. For the added projects there were a significant number of 138 and

230 kV facilities that were impacted, the primary voltages of facilities in the area. There were also some 161 and 345 kV facilities impacted.

Reynolds to Sullivan 765 kV

Reynolds – Sullivan 765 did not result in significant congestion relief without additional support and therefore was not selected to be added to the portfolio. Minimal constraints were resolved in the steady state analysis and in some situations additional constraints were created. Southern Indiana 765 may be reviewed further in later tranches with a continuous 765 kV path.

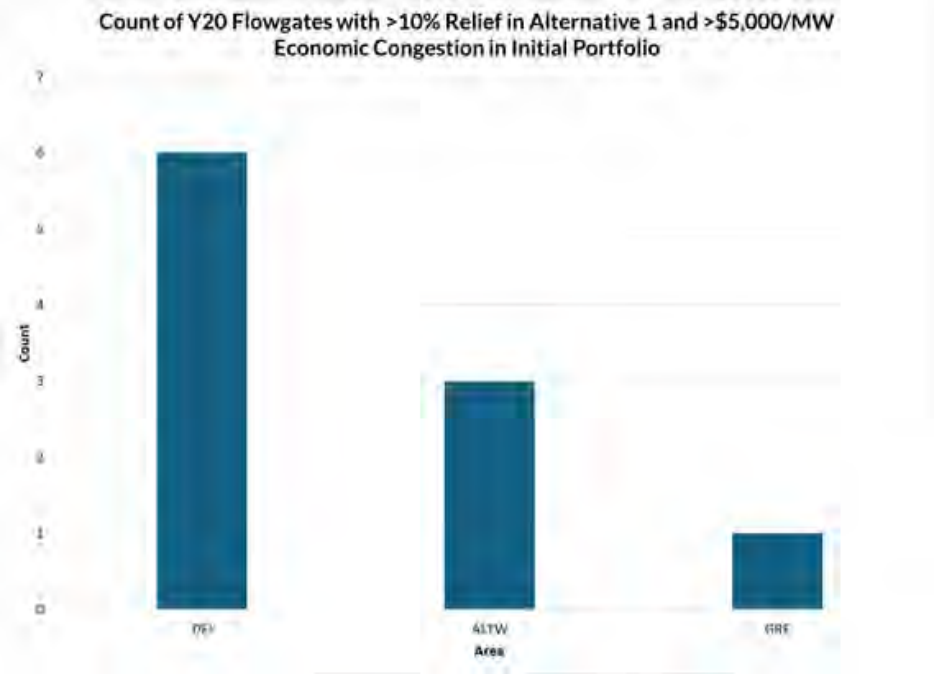


Figure 2.39: Count of Year 20 Flowgates with Congestion Relief for Alternative 1

This graph shows the number of Year 20 flowgates with greater than 10% congestion relief by Alternative 1 which had greater than $5,000/MW congestion measure in the initial portfolio.

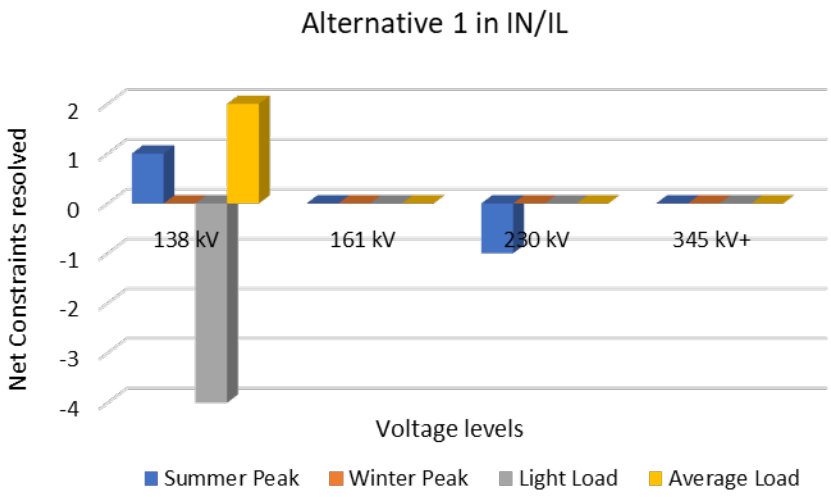


Figure 2.40: Figure: Indiana and Illinois Constraints resolved by Voltage level by Alternative 1 Indiana project

This graph shows the number of net constraints (monitor element and contingency pairs) resolved (= constraints resolved minus new constraints created) by Alternative 1 by voltage kV level and by core models. Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 2 - New 345 kV in Michigan connecting proposed Tranche 2 facilities with Tranche 1

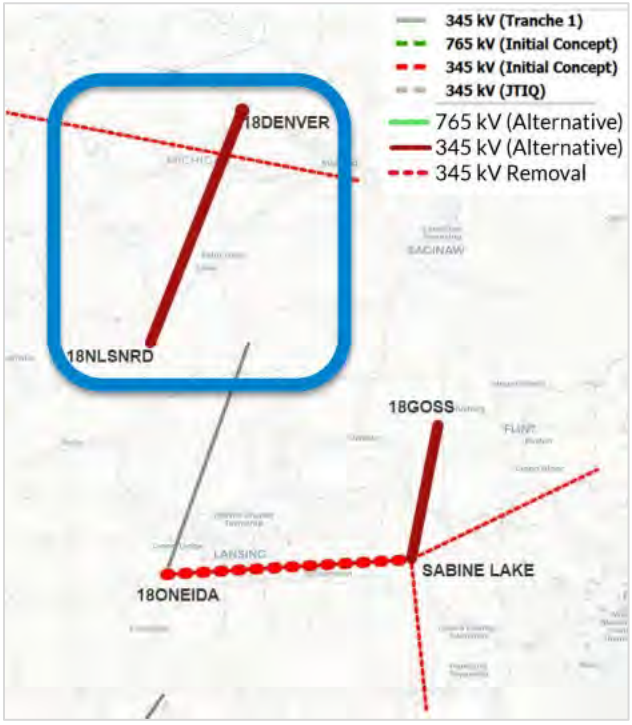


Figure 2.41: Map shows selected Alternative 2 projects in blue boxes

Alternative 2 adds four projects to the portfolio and unlocks generation in the West as a complement to existing and 765 kV paths in the initial draft portfolio.

- 2 project proposals to add in MI
    - Denver – Nelson Road 345
        - New Denver Substation
        - Two 345/138 transformers at Denver
    - Sabine Lake – Goss 345
- 1 project proposal to replace in MI
    - Oneida – Sabine Lake 345 (replaced by Sabine – Goss 345 in this Alternative)

Alternative 2 facilitates Future 2A fleet change by improving economic congestion relief, resolving constraints and reducing loading stress across all reliability models and providing more production cost savings for the MISO Midwest.

- 345 kV from Denver – Nelson Road resolves constraints and provides significant congestion relief on Michigan flowgates and is added to the portfolio.
- 345kV from Sabine Lake – Goss 345 did not show significant congestion relief over the initial portfolio and resolved a few constraints while stressing other system elements and therefore was not selected to be added to the portfolio as a replacement for Oneida – Sabine Lake 345 kV.

Denver – Nelson Road 345 kV

Alternative 2 Denver to Nelson Road resolves constraints (especially in Summer Peak models) and reduces loading stress across all models by increasing the connectivity of the proposed Tranche 2 Ludington to Tittabawassee 345 kV line. This alternative adds a tab to the proposed 345 kV line at Denver and adds a 345 kV line from Denver to the Tranche 1 Nelson Road substation.

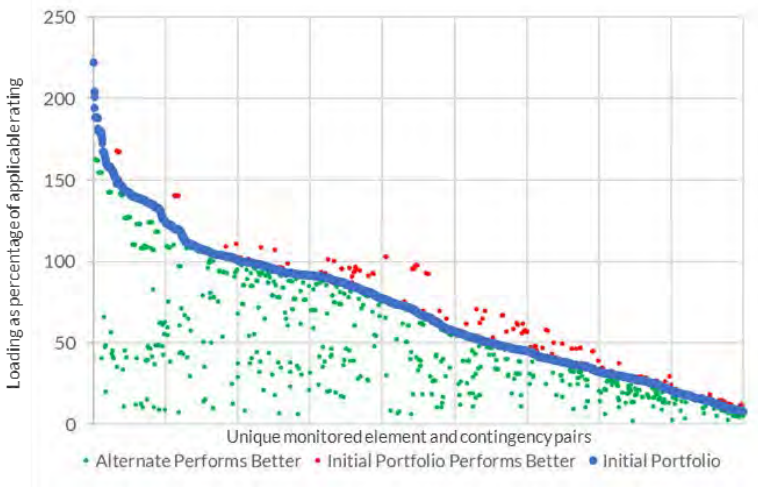


Figure 2.42: Scatter plot showing Denver-Nelson Road 345 kV performance as compared to Initial Portfolio

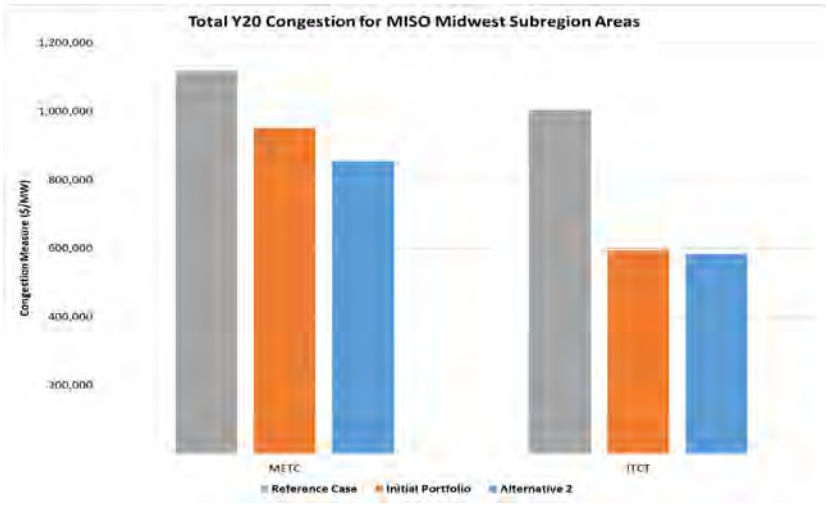


Figure 2.43: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 2

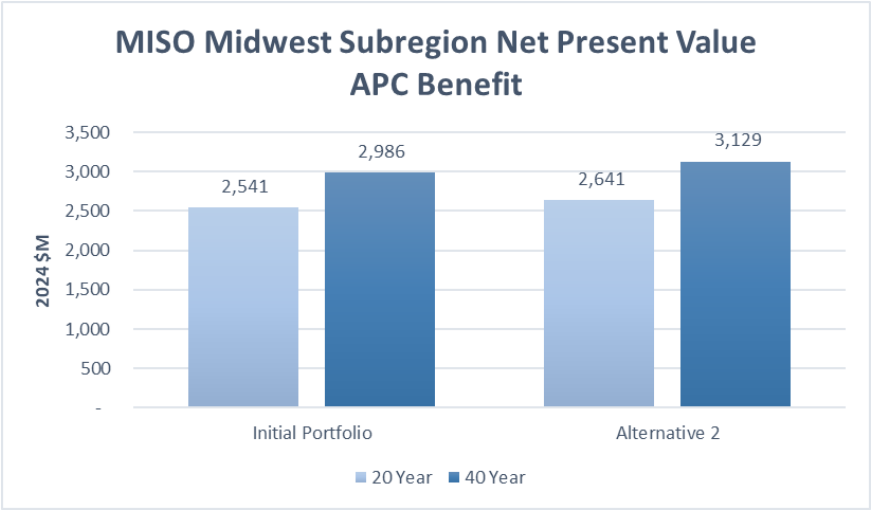


Figure 2.44: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Results based on analysis performed during portfolio definition. Results are not inclusive of all portfolio value and final results are expanded on by the business case analysis.

Goss – Sabine Lake 345 kV

The Goss to Sabine Lake 345 kV replaced a proposed Tranche 2 Oneida to Sabine 345 kV facility. This facility resolved a few constraints while stressing other system elements in the reliability analysis. In the economic analysis, Goss – Sabine Lake 345 kV did not show significant congestion relief over the initial portfolio. Therefore, this alternative was not selected to be added to the portfolio as a replacement for Oneida – Sabine Lake 345 kV.

Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 3 - Replacement of Lakefield Junction to Plano 765 kV projects in Minnesota and Wisconsin by moving the starting location to Brookings heading north of Twin Cities to Chisago onto Wisconsin Highway 22 to Paddock and retaining same end point at Plano 765

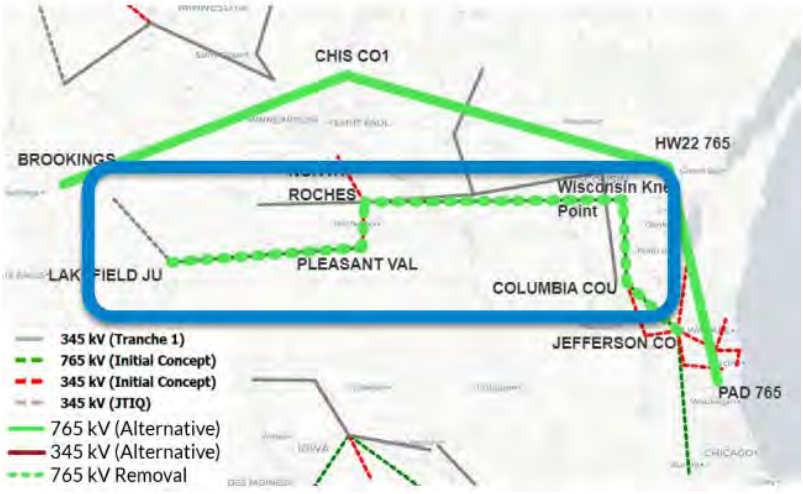


Figure 2.45: Map shows selected initial portfolio projects in blue boxes, Alternative 3 projects were not selected

Alternative 3 replaces the entire 765 kV project in MN/WI/IL with a configuration that is north of twin cities and is approximately 200 miles longer.

- 1 project proposal to add SD/MN/WI/IL
    - Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV
- 1 project removed in MN/WI/IL
    - Lakefield Junction – Pleasant Valley – North Rochester – Jefferson Co – Plano 765 kV
        - electrically comparable to the final configuration of LRTP projects 24, 26, 30, and 31
- Multiple 345 kV changes (additions and removals) in Wisconsin were incorporated with this alternative (not shown on map)

Alternative 3 targeted the same constraints as Alternative 1, but Alternative 1 outperformed Alternate 3 on the loading stress reduction metric, curtailed energy, congestion relief, and production cost savings.

- 765 kV from Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 showed marginal or mixed results in improving congestion relief over Alternative 1 and resolved a few constraints while stressing other system elements and therefore was not selected to be added to the portfolio.

Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV

Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV, in Alternative 3, showed marginal improvements in economic congestion compared to Alternative 1, but did not facilitate Future 2A fleet

change as well as Alternative 1. Alternative 3 had mixed results on reducing congestion in Wisconsin; reducing congestion in some areas and aggravating it in others. Compared to Alternative 1 and the initial draft portfolio, Alternative 3 did not enable as much renewable generation in the area curtailing approximately 8 GWh more renewable energy than Alternative 1.

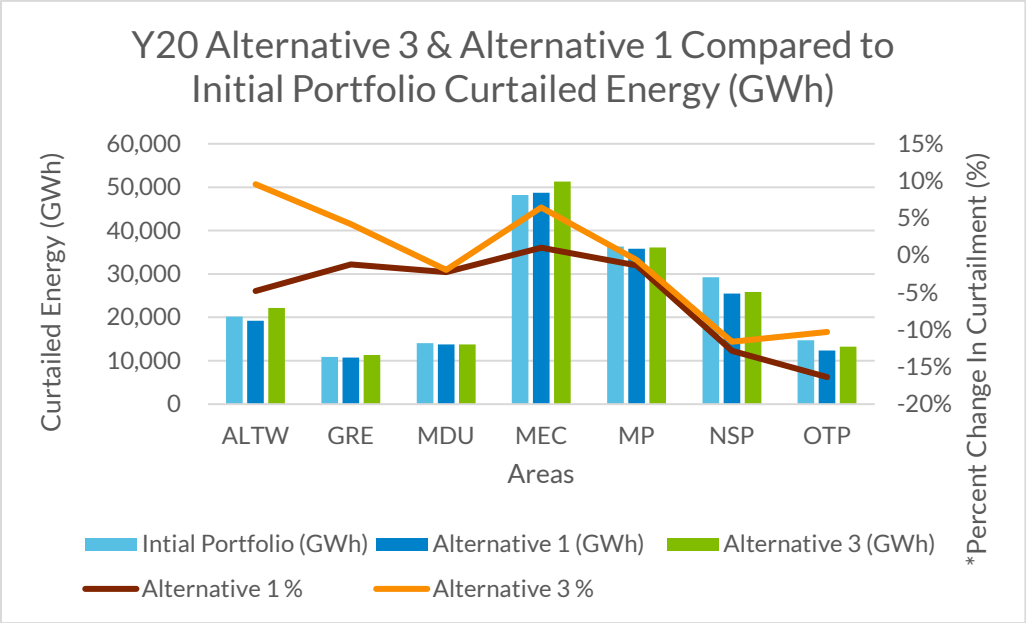


Figure 2.46: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1 vs. Alternative 3

Alternative 3 had lower Adjusted Production Cost Savings as compared to Alternative 1 and the initial draft portfolio.

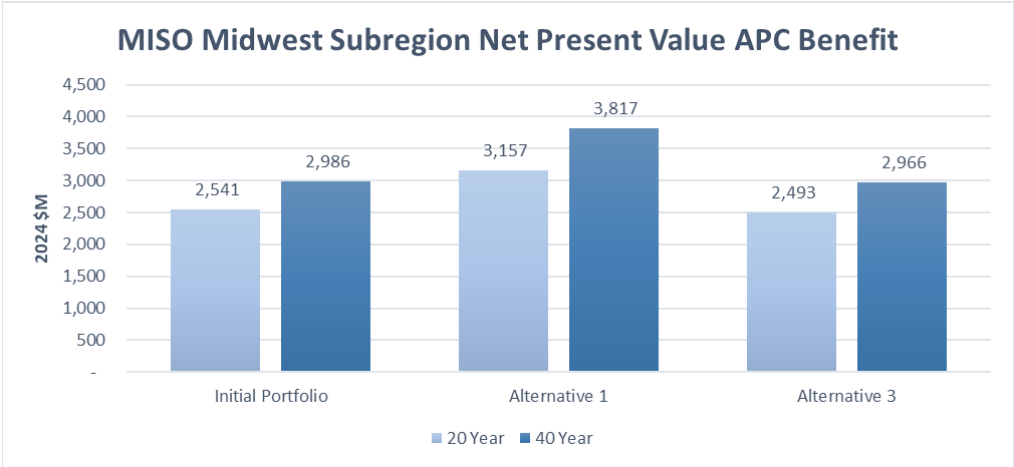


Figure 2.47: Initial Portfolio vs. Alternative 1 vs. Alternative 3 Adjusted Production Cost Savings

Alternative 3 was considered looking at the impacts of the MN area facilities and the WI area facilities considering the local areas that were impacted and comparing those reliability results.

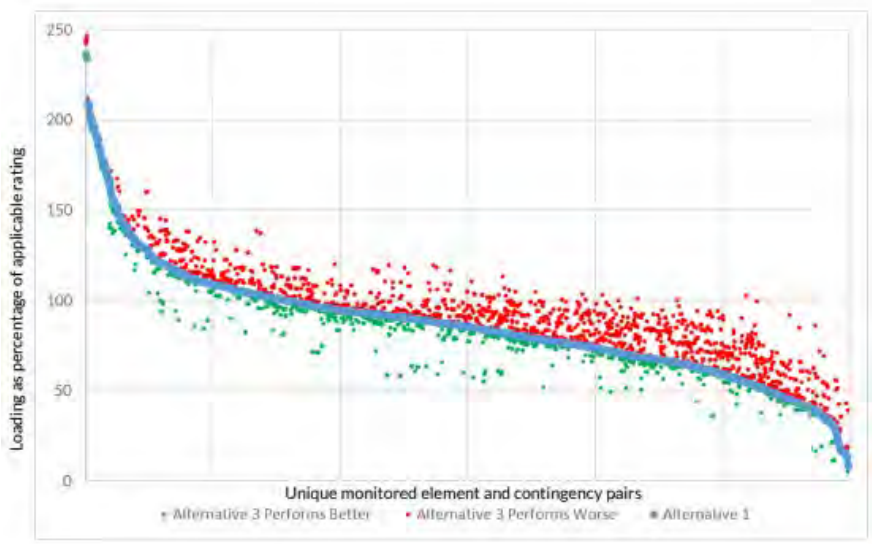


Figure 2.48: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio with Alternative 1 in MN

Alternative 1 overall performed better for the Minnesota area than Alternative 3 due to better connecting the portfolio to the rest of the MISO region, allowing for more connections to Iowa since it traverses south of the Twin Cities. Alternative 1 also benefits more from Tranche 1 345 kV portfolio in the area as well.

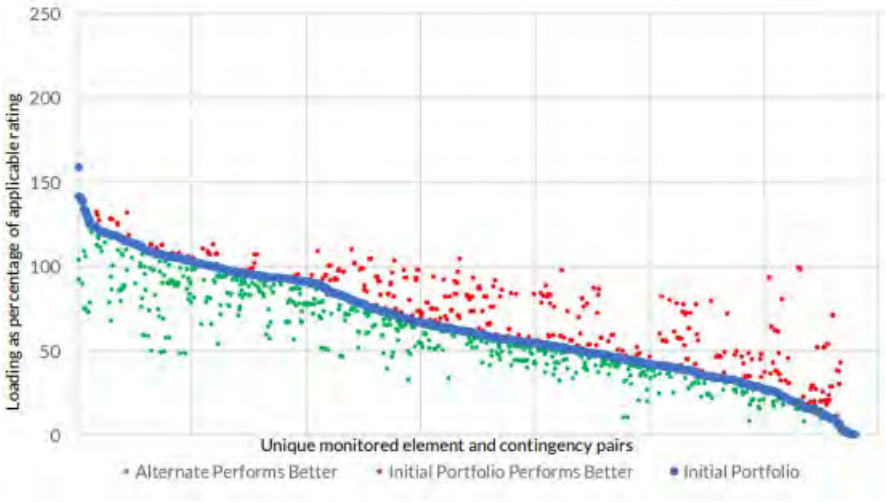


Figure 2.49: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio in WI

For Wisconsin, the results were inconclusive whether incorporating the alternative resolved more violations, as both violations were created and resolved. The result was retaining the original Wisconsin portfolio in this area. Alternative 3 was not selected to move forward, instead a combination of the proposed facilities in this area with the Alternative 1 additions (Big Stone to Brookings County 765 kV and Lakefield Junction to East Adair 765 kV). Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 4 - Add northern MN outlet from Tranche 1 facilities and add Southern IN reinforcements enabling interstate transfers. Evaluates Michigan 345 kV project proposal

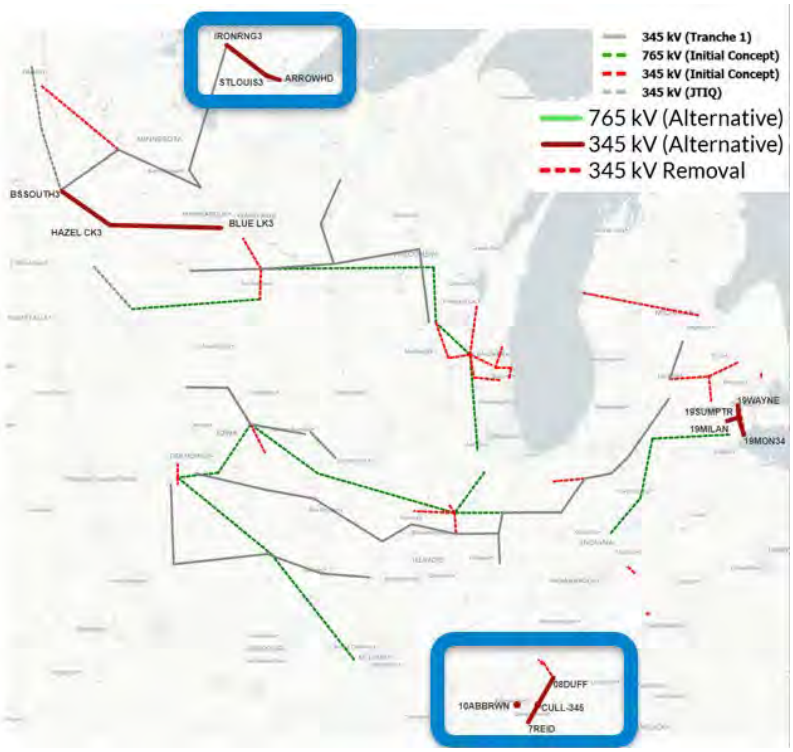


Figure 2.50: Map shows selected Alternative 4 projects in blue boxes

Alternative 4 adds four projects to the portfolio in Michigan, Indiana/Kentucky, Southern Minnesota and Northern Minnesota.

- 2 project proposals to add in MN
    - Iron Range – St Louis Co. – Arrowhead 345 kV (Northern MN)
    - Big Stone South – Hazel Creek – Blue Lake 345 kV (Southern MN)
- 1 project proposal to add in IN/KY
    - Duff – F. B. Culley – Reid EHV 345 +A. B. Brown 345/138 XF (1) and F. B. Culley 345/138 kV XFs (2)
- 1 project proposal to add in MI
    - Milan – Sumpter 345
- No projects from initial portfolio replaced or removed

Select projects within Alternative 4 facilitates Future 2A fleet change by increasing the deliverability of renewable energy and providing more production cost savings for the MISO Midwest.

- 345 kV in Northern Minnesota resolved constraints, reduced loading stress and improved economic congestion in Northern Minnesota and is added to the portfolio.
- 345 kV in Southern Indiana reduced loading in the area and supports interstate transfers and is added to the portfolio.
- 345 kV in Southern Minnesota resolved similar constraints in the region as Alternative 1 with mixed results observed on the loading reduction metric and was not selected to be added to the portfolio.
- Milan – Sumpter 345 kV had minimal economic impact in Michigan and had minimal impact on transmission facilities in the area therefore was not selected to be added to the portfolio.

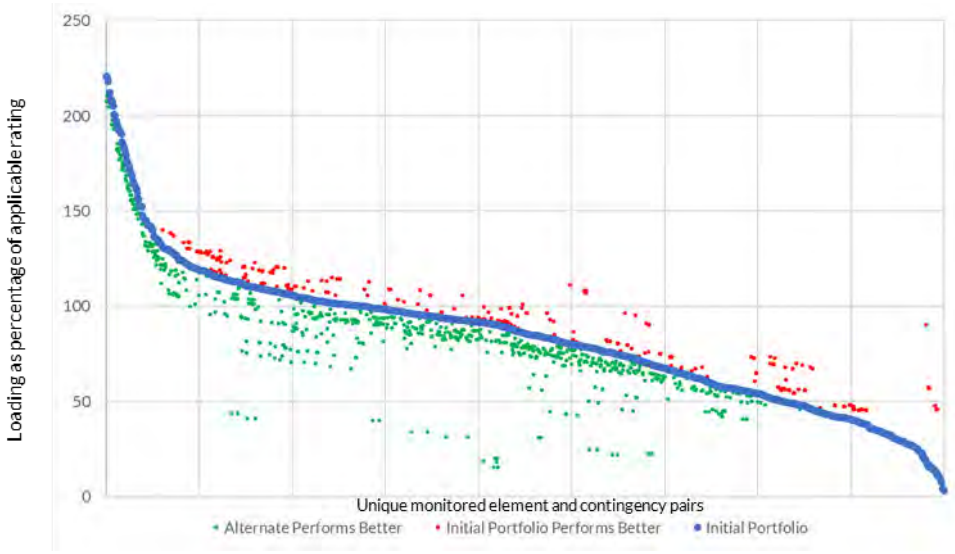


Figure 2.51: Scatter plot showing Iron Range- Arrowhead 345 kV performance as compared to Initial Portfolio

Alternative 4 in Northern Minnesota resolves constraints and reduces loading stress for the majority of impacted flowgates with healthy base case loading on the project in all models.

Iron Range – St Louis Co. – Arrowhead 345 kV provides additional congestion relief in Northern Minnesota in Iron Range and south of Duluth.

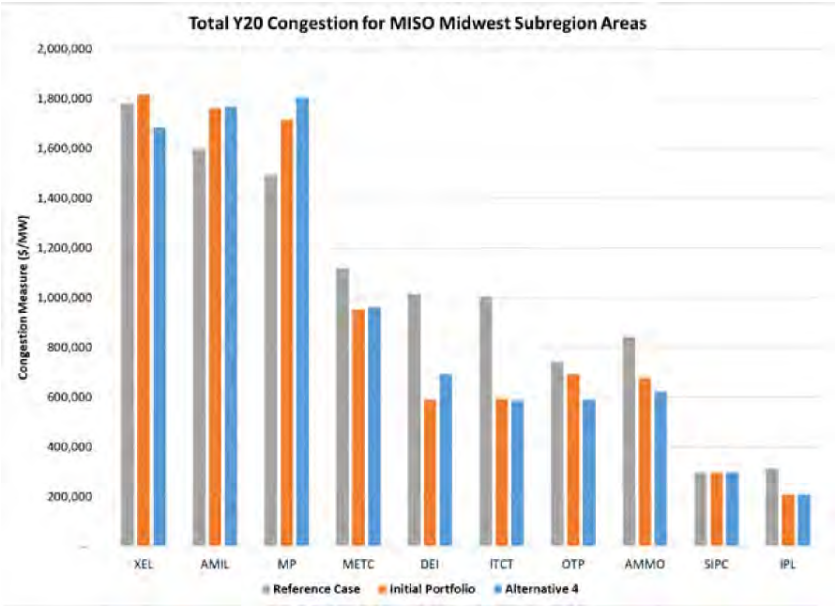


Figure 2.52: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (MN)

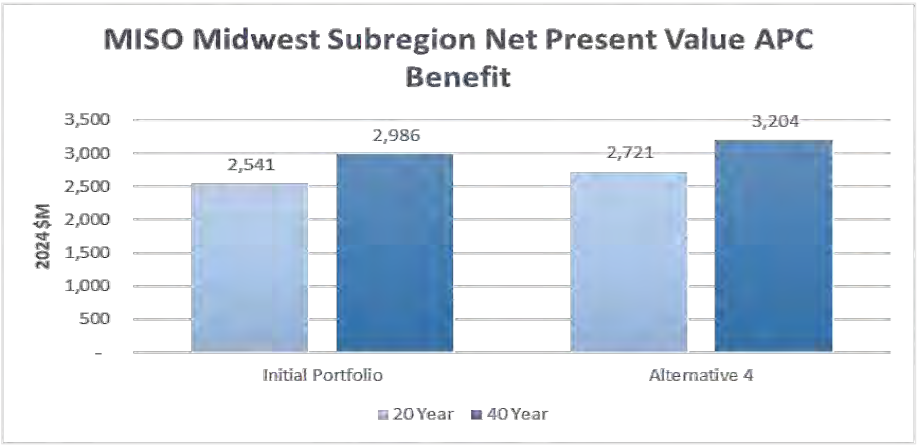


Figure 2.53: Initial Portfolio vs. Alternative 4 Adjusted Production Cost Savings

The Northern Minnesota 345 kV also shows economic value due to congestion relief and increases the Adjusted Production Cost Savings for the Midwest subregion as compared to the initial portfolio.

Duff – F. B. Culley – Reid EHV 345, A. B. Brown 2nd Transformer, F. B. Culley 2 Transformers

Alternative 4 project in Indiana resolves key constraints in the region and assists in reducing the loading on system elements in Southern Indiana. In addition, loading reductions occurred on constraints in additional transfer scenarios to enable regional flows.

Duff – F. B. Culley – Reid EHV 345 and A. B. Brown and Culley transformer alternative resulted in an overall downward trend in congestion in Indiana. Congestion reduction supports transfer capability in MISO Central and 345 kV facilities provided economic value for southern Indiana, Illinois and Kentucky.

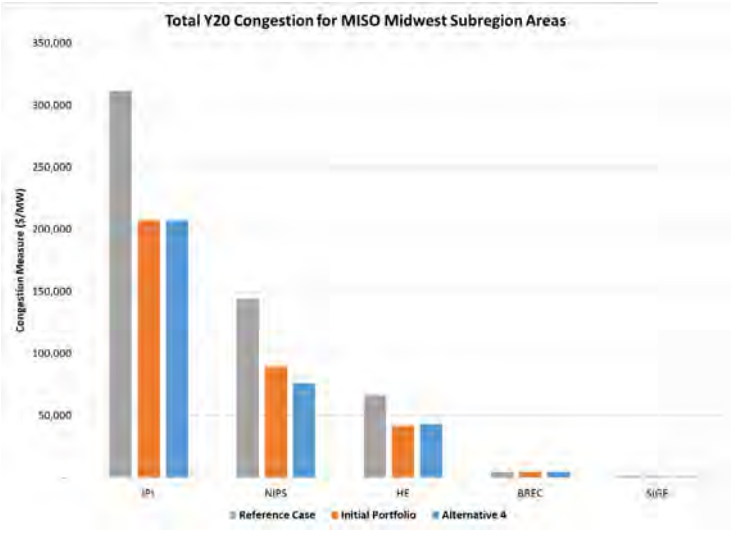


Figure 2.54: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (IN)

Big Stone South – Hazel Creek – Blue Creek 345 kV

The Alternative 4 Southern Minnesota project resolves constraints in the region; however, these are similar constraints to those resolved by Alternative 1; mixed results were observed on the loading reduction metric. 345 kV Southern MN addresses similar constraints as Alternative 1, therefore was not selected for the final portfolio.

Milan – Sumpter 345 kV

Alternative 4 project in Michigan had minimal impact on transmission facilities in the area from a reliability analysis. In addition, the Milan – Sumpter 345 kV project had minimal economic impact for Michigan. Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 5 - Central IA additional source to the proposed Twinkle 765 kV substation



Figure 2.55: Map shows selected Alternative 5 projects in blue boxes

Alternative 5 adds three projects to the portfolio in Indiana, Missouri and Iowa

- 1 project proposal to add in Indiana
    - St. John – Burr Oak 345
- 2 project proposals to add in Missouri
    - Montgomery – Sioux – Stallings 345
    - Kingdom City – Bland – Labadie 345
- 1 project proposal to add in Iowa
    - Lehigh – Twinkle 345
- No projects from initial portfolio replaced or removed

Alternative 5 facilities build upon Tranche 1 and proposed Tranche 2 facilities in central Iowa further facilitating Future 2A and high voltages.

- 345 kV line from Lehigh to Twinkle further connected Tranche 1 Marshalltown 345 kV outlets (Marshalltown and Twinkle are same location) providing additional sources for the 765 kV outlet under contingency operation. This project was added to the portfolio.
- 345 kV facilities proposed in MO; Montgomery to Sioux to Stallings and Kingdom City to Bland to Labadie, resulted in minimal impact on transmission facilities in the area and was not selected to add or modify the portfolio.
- 345 kV line in northern Indiana St. John to Burr Oak 345 kV was considered and only impacted one constraint, resulting in no addition or modification to the portfolio.

Lehigh – Twinkle 345 kV

Alternative 5 in Iowa provides an additional source to the proposed Twinkle 765 kV substation, with healthy loadings confirming its utilization. The Lehigh -Twinkle 345 kV provided support to the 765 kV network and a marginal impact to the overall Adjusted Production Cost Savings as compared to the original portfolio.

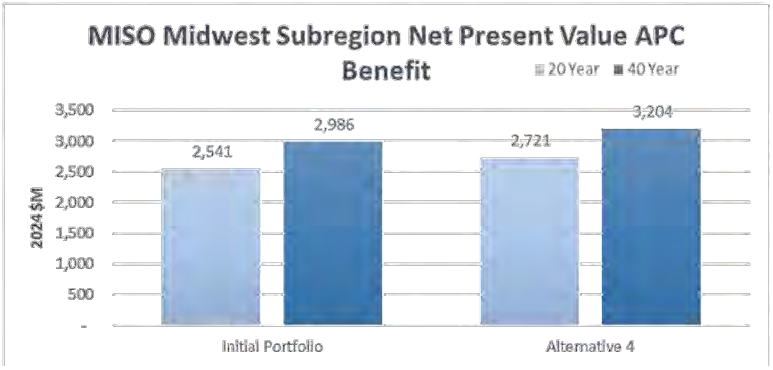


Figure 2.56: Initial Portfolio vs. Alternative 5 Adjusted Production Cost Savings

Montgomery – Sioux – Stallings 345, Kingdom City – Bland – Labadie 345 kV

Alternative 5 in Missouri has minimal impact on transmission facilities in the area. This project resolved high voltage constraints and assisted in reducing loading stress in the area. The Missouri area projects showed minimal congestion relief or economic value over the initial portfolio.

St. John – Burr Oak 345 kV

Alternative 5 in Indiana has minimal impact on transmission facilities in the area. The St. John – Burr Oak 345 kV project showed minimal congestion relief or economic value over the initial portfolio.

Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 6 - Replace 765 kV proposed in MO with 345 kV projects connecting to Tranche 1 facilities



Figure 2.57: Map shows selected Alternative 6 projects in blue boxes

Alternative 6 replaces the 765 kV project in IA/MO with 345 kV projects in the St. Louis metropolitan area in Missouri.

- 1 project proposal to add in MO
    - Maywood – Belleau – MRPD- Sioux, MRPD – Bugle –Roxford /Gateway) 345
- 1 project removed in IA/MO
    - East Adair (IA) – Labadie 765 kV

Alternative 6 facilities build upon Tranche 1 and enables regional flows and removes 765 kV facilities into MO that may be reviewed further in later tranches with a continuous 765 kV path.

- 345 kV facilities in Missouri resolved constraints in MISO Central, reduced loadings in the Missouri area and provided economic value while enabling interstate transfers and was added to the portfolio.

- 765 kV from Iowa to Missouri did not result in significant congestion relief without additional support and was removed from the portfolio.

Maywood – Belleau – MRPD- Sioux, MRPD – Bugle -Roxford/Gateway) 345 kV + XFs

The 345 kV facilities reduced congestion supporting transfer capability in MISO Central.

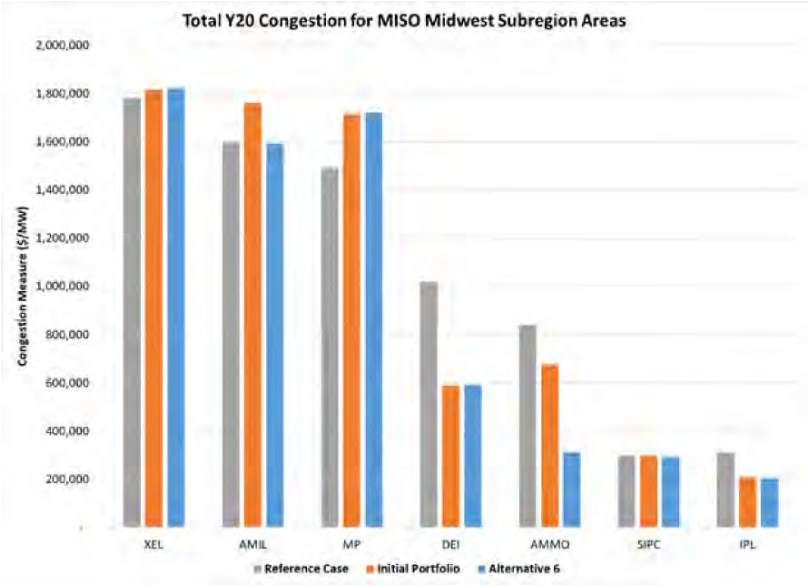


Figure 2.58: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 6

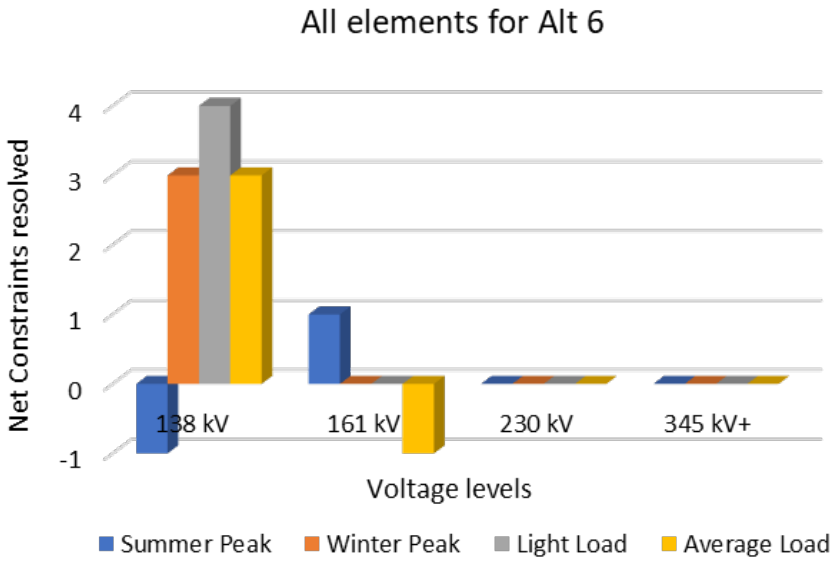


Figure 2.59: Constraints resolved by Voltage level by Alternative 6 project

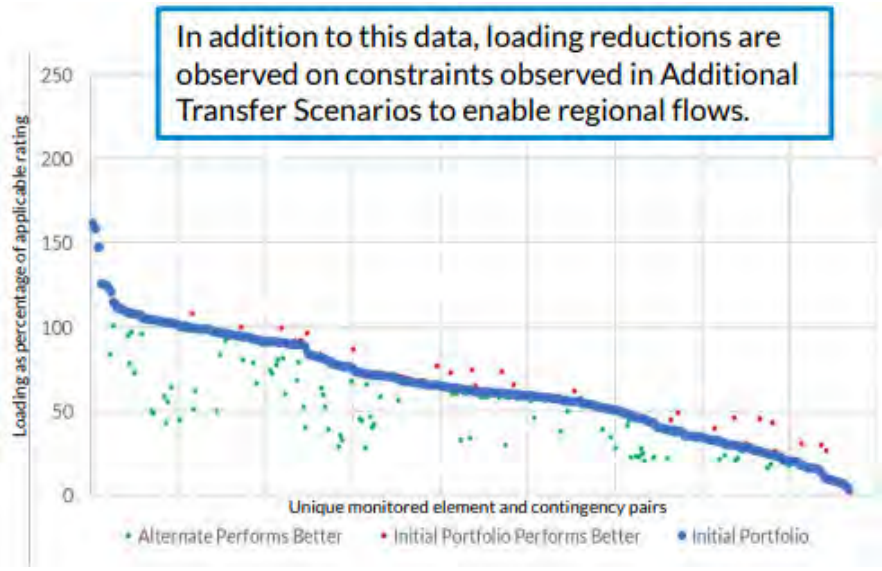


Figure 2.60: Scatter plot showing Alternative 6 performance as compared to Initial Portfolio

The Iowa - Missouri 765 kV line did provide economic value but did not result in significant congestion relief without additional support and may be reviewed further in later tranches with a continuous 765 kV path. Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

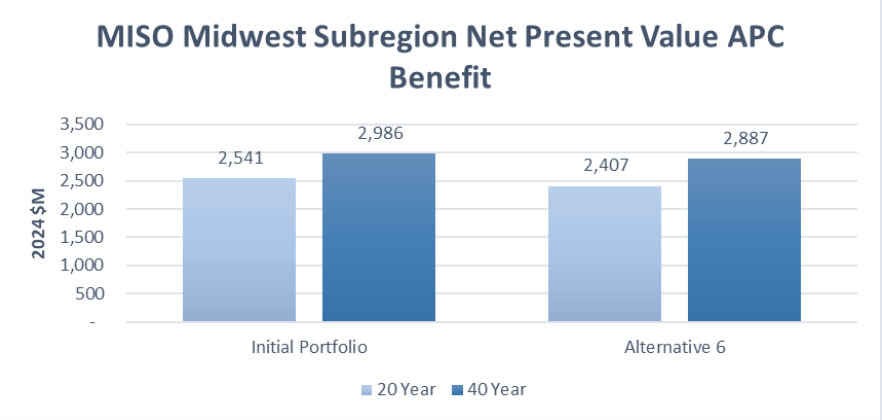


Figure 2.61: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Refine Solutions

After identifying the issues that would be addressed in Tranche 2.1, and performing the above alternatives assessment, MISO developed a near-final portfolio of solutions to resolve those issues based on results from reliability and economic analysis using the criteria, data, tools and methodology described in the prior sections of this document and in the economic and reliability study whitepaper.

Tranche 2.1 portfolio includes 24 projects across the MISO Midwest subregion, estimated at $21.8 billion. The projects are targeted to go in service from 2032 to 2034. The least-regrets, robust portfolio provides the following:

- Facilitates a more economical dispatch for MISO Midwest resulting in $8.1B in Adjusted Production Cost (APC) savings
- Reduces economic congestion for MISO Midwest by 29.5%
- Reduces MISO Midwest curtailment by 11.2% (27.1M MWh)
- Decreases MISO Midwest load serving costs and reduces price separation
- Resolves more than 60% of >200 kV constraints for single initiating and multiple element contingency events
- Paired contingency (P3/P6) analysis shows on average more than 70% of thermal violations are resolved for all voltage levels
- Reduces the majority of the loadings below Safe Loading Limits
- Enables regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty

Step 5: Evaluate and Justify Solutions

Total Reliability Results

Analysis with twelve reliability models representing various system conditions and dispatch patterns helped MISO better understand system performance with and without LRTP portfolio of projects. MISO monitored flow on lines and voltage at substations with and without the LRTP portfolio of projects. To better assess the impact and severity of overloads and voltage violations across multiple lines and substations, MISO utilized industry-standard ranking criteria known as Severity Indices. The severity index formulation is a modified Contingency Severity Index (CSI) from Siemen PTI's PSS/MUST. This approach enables straightforward comparisons of overall system performance across various models, rather than focusing solely on specific monitored elements or contingency pairs.

The Thermal Severity Index provides an overview of the performance of the Tranche 2.1 portfolio taking into consideration the magnitude of thermal and voltage violations, respectively, from the contingency analysis. The Thermal and Voltage Severity Index values calculated for the Tranche 2.1 portfolio point to significant improvement in the overall system performance.



Figure 2.62: Thermal Severity Index and Voltage Severity Index with and without the Tranche 2.1 portfolio

Large Angular separation across the Midwest subregion was noticed while building models, as power was being transferred via longer, inefficient routes leading to increased risk of angular separation and instability, and increased losses. The Tranche 2.1 portfolio reduces angular separation across the MISO transmission system in the most stressed case by 47°, showing that power can take more direct paths from resources to load, enabling additional flexibility during outages.

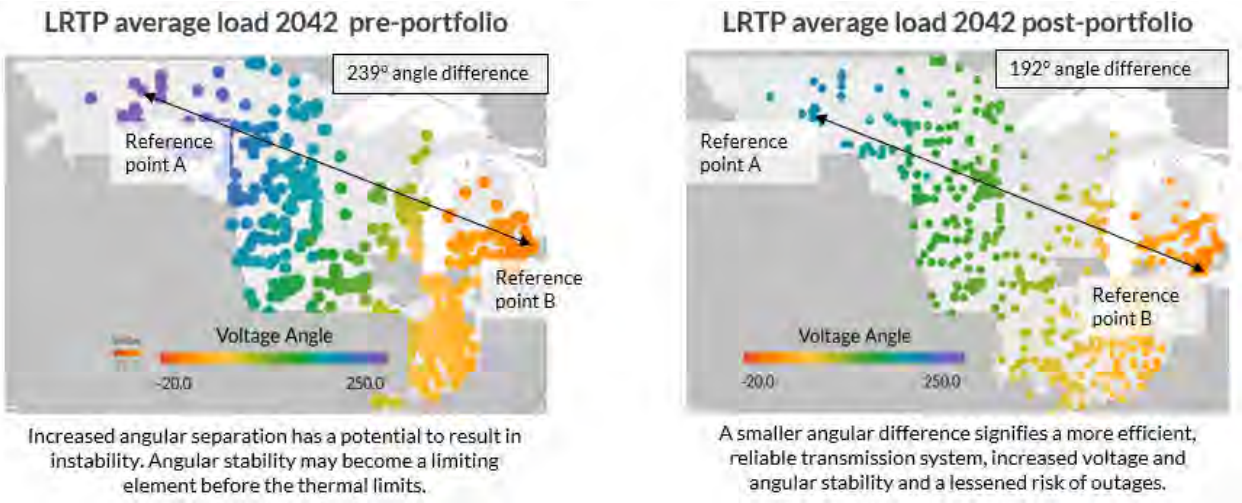


Figure 2.63: Angular separation with and without the Tranche 2.1 portfolio

Voltage and Reactive Support

Maintaining optimal loading levels is essential for reliable operation and effective voltage regulation in (Extra High Voltage) EHV transmission lines. When EHV lines operate below their Surge Impedance Loading (SIL), they generate reactive power, functioning as a source or reactive power that can alleviate voltage

issues elsewhere in the grid. To enhance system reactive support and reduce reliance on other voltage support devices, MISO intentionally planned the system to increase the SIL of regional lines when practical (e.g., use of 765 kV options and high-SIL 345 kV options for very long 345 kV lines), thus providing substantial reactive power capability from the regional transmission system under most conditions. Since regional flows are lower during summer peak conditions, which is the time when reactive power demand from loads tends to be highest, the lower regional flows that typically occur in the summer (because a much greater percentage of the generation output in summer is local) allow for even more reactive power capability from the regional lines, decreasing the need for local voltage support equipment during these conditions.

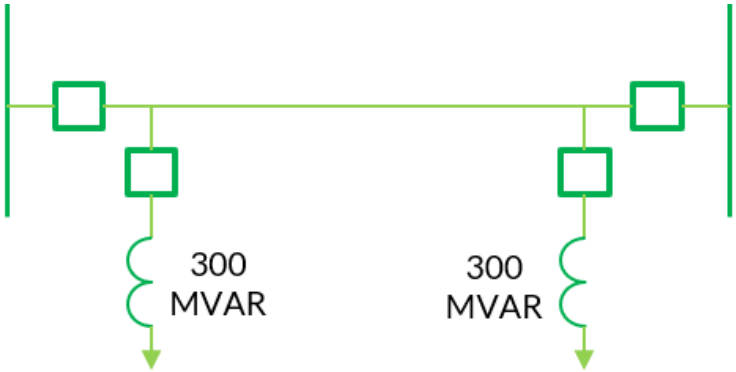


Figure 2.64: Default 765 kV line configuration includes line-side switchable shunt reactors to manage high voltages and mitigate Ferranti Effect during switching

To better manage high voltage issues and allow for greater flexibility, the default 765 kV line configuration includes line-side switchable 300MVAr shunt reactor banks at each terminal to control high voltages and mitigate the Ferranti Effect during switching. The reactor banks can also be switched off by operators when line flows exceed the SIL and it is necessary to maintain acceptable voltage levels in the area.

The LRTP Tranche 2.1 portfolio addressed most of the voltage violations. The average 765 kV N-0 loadings in the core cases are as follows:

- Summer Peak: 33.7% of Surge Impedance Loading
- Winter Peak: 50.1% of Surge Impedance Loading
- Average: 60.1% of Surge Impedance Loading
- Light Load: 58.7% of Surge Impedance Loading

Due to the Surge impedance loading of 2440 MW for 765 kV, the 765 kV system is providing substantial reactive power, particularly in the summer peak case where voltage support is most needed. This substantially reduces the need for other voltage support devices.

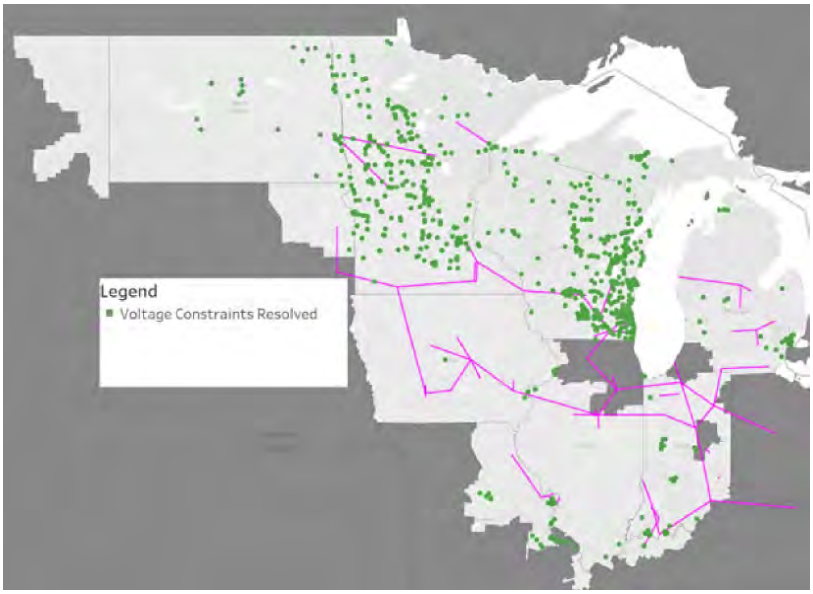


Figure 2.65: Green dots represent a voltage constraint observed in core models and is mitigated by the final portfolio

Since reactive support is inherently local—given that reactive power cannot be transferred over long distances—the remaining low and high voltage issues, along with overloaded transmission lines due to local load growth and specific generation interconnections, will be addressed through various shorter-term planning processes. These include the annual MTEP reliability planning and the generator interconnection processes, as specific load and generation locations are identified.

Dynamic Assessment

The portfolio enhances the overall stability of the system as demonstrated by a significant reduction in the number of transient voltage violations, low damping violations and relay trip violations. The 2042 average load case represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and 100% renewable penetration meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. The 2042 summer peak model represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

The Transient Stability Index (TSI) is an industry acceptable metric used in TSAT (Transient Security Assessment Tool) which assesses the severity of each disturbance. A higher TSI for a disturbance represents a more stable system response. The Tranche 2.1 portfolio resolved a vast majority of transient voltage violations for the 2042 AVG model and boosts the system performance in the 2042 SUM model. Approximately 90% of transient voltage violations were resolved in the 2042 AVG stability model, and 30% of transient voltage violations were resolved in the 2042 SUM peak stability model.

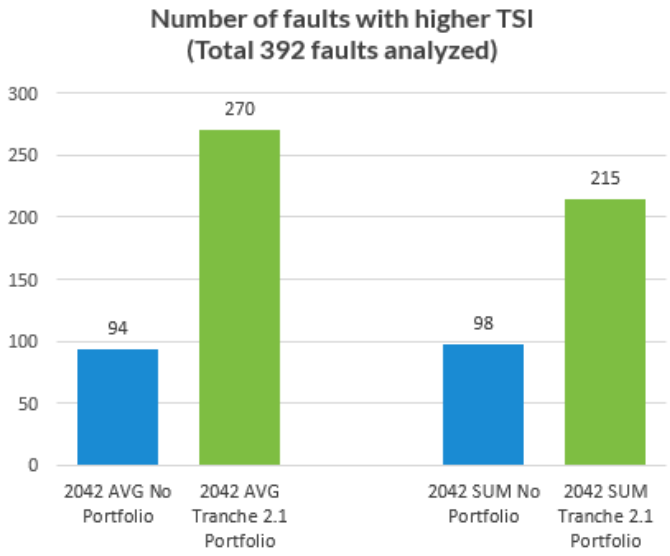


Figure 2.66: Transient Stability Index with and without the Tranche 2.1 portfolio

Many of the remaining transient voltage violations will have better resolution through site specific dynamic parameter tuning, and through the annual MTEP reliability planning and the generator interconnection planning processes. The portfolio resolved all the low damping violations and reduced the total number of relay violations.

Transfer Analysis

East to West Transfer Scenario underscores the portfolio's flexibility to accommodate significant shifts in generation during low renewable output in the West, while also highlighting the bi-directional nature of the system, with flows reversing as conditions change.

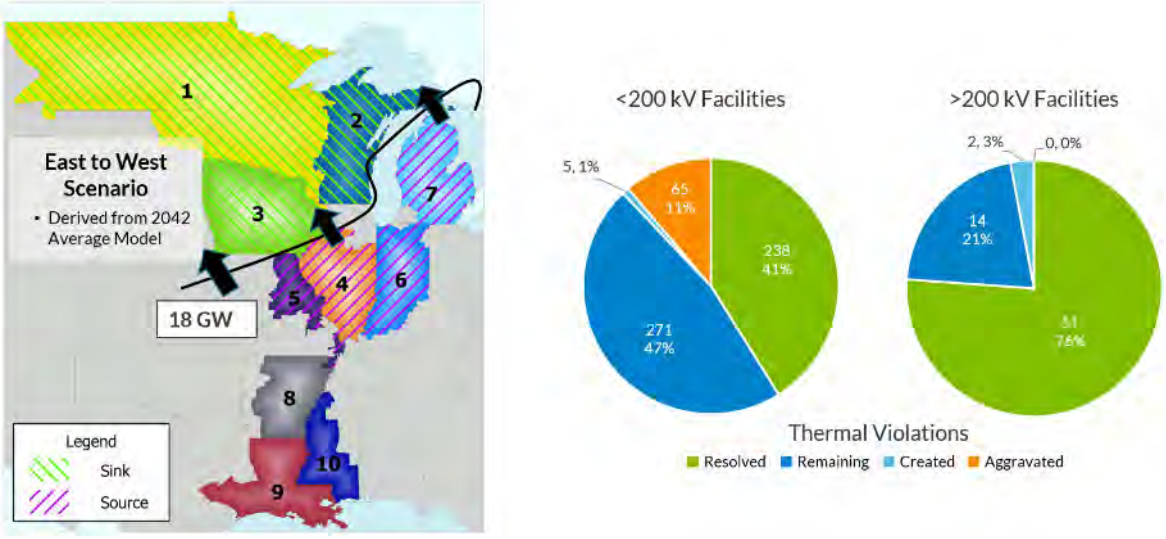


Figure 2.67: East to West Transfer results summary with the Tranche 2.1 portfolio

All reliability core models had natural direction of flows from West to East based on data from future hourly profiles; however, there were a number of hourly profiles where flow was in the East to West direction. To cover this credible scenario, MISO utilized the data from Futures to build an East to West scenario. In the East to West transfer an additional 13% unique limiting elements were observed beyond the unique limiting elements in the core models (average load, summer peak, light load, and winter peak). The LRTP 2.1 portfolio resolves more than 75% of all 200 kV and above constraint violations observed in the East to West scenario.

The Lowers to Uppers Scenario highlights the flexibility of the portfolio to accommodate increased output in the Central Region and reliably deliver power to other MISO Regions.

Studying this scenario introduced an additional 6% unique limiting elements beyond the core models. The LRTP Tranche 2.1 portfolio resolves 70% of all 200 kV and above constraint violations observed in this scenario.

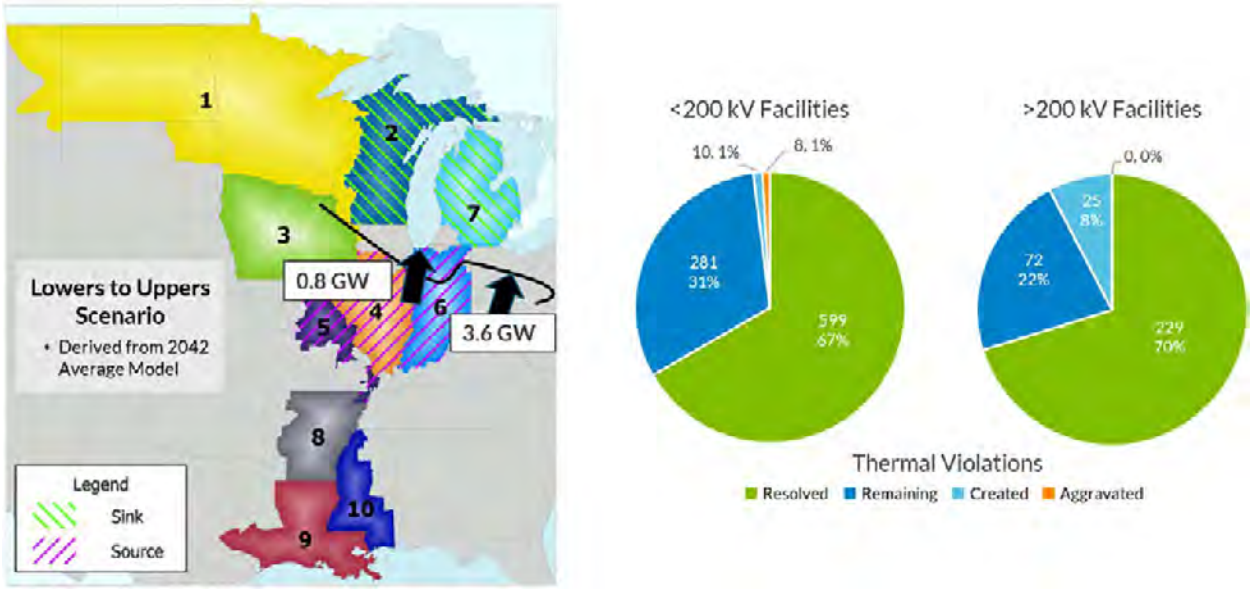


Figure 2.68: Lowers to Uppers Scenario results summary with the Tranche 2.1 portfolio

The Winter Peak Low Renewable scenario captures multi-day periods of low renewable output, particularly during early morning hours and regional winter freezes. The LRTP portfolio enables reliance on conventional local resources to reliably support load during winter events that have historically impacted the MISO system.

This scenario represents the lowest renewable scenario of all core models and additional scenarios. All conventional resources are dispatched to their maximum nameplate capacity. Studying this scenario introduced an additional 48% unique limiting elements beyond the unique limiting elements in the core models. LRTP Tranche 2.1 portfolio resolves 52% of all 200 kV and above constraint violations observed in this scenario.

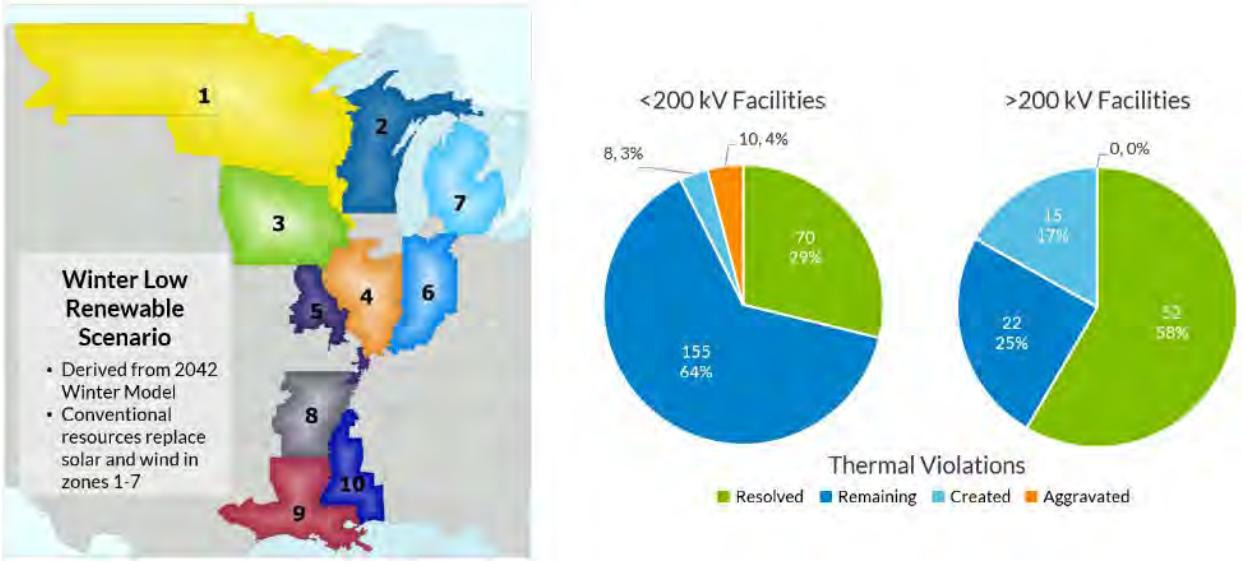


Figure 2.69: Winter Peak Low Renewable Scenario results summary with the Tranche 2.1 portfolio

The Twilight Summer Scenario demonstrates a large increase in reliability on the 200 kV and above system as the resource mix transitions during sunset at peak load.

The Twilight scenario dispatches down solar and wind resources to 10% of nameplate capacity. In this scenario, batteries are assumed unavailable. Studying this scenario introduced an additional 20% unique limiting elements beyond the unique limiting elements in the core models. The LRTP Tranche 2.1 portfolio resolves 72% of all 200 kV and above constraint violations observed in this scenario.

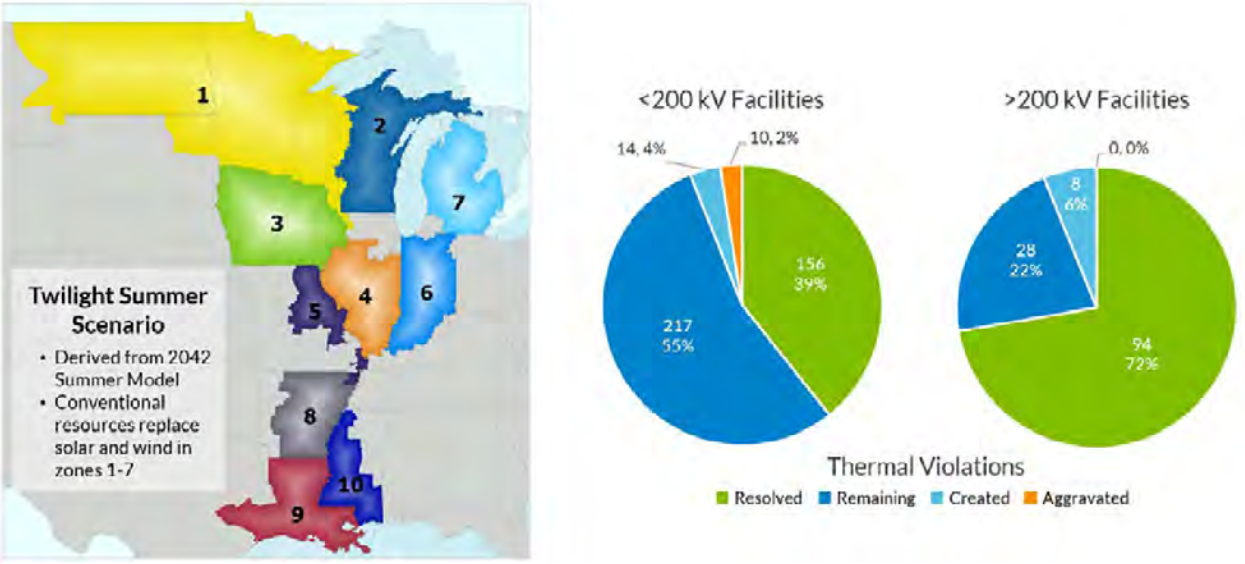


Figure 2.70: Twilight Summer Scenario results summary with the Tranche 2.1 portfolio

Total Economic Results

Analysis with annual economic models represent various system conditions and dispatch patterns helped MISO better understand system performance with and without the LRTP portfolio of projects. Unless otherwise indicated, the measures described in this section were derived from the 2042 Future 2A PROMOD models. The Tranche 2.1 portfolio enhances the economic value for the MISO Midwest subregion and enables member plans for fleet transition and load growth. The economic analysis revealed the Tranche 2.1 portfolio:

- Reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5%
- Reduces curtailment in the MISO Midwest subregion by 27.1M MWh (11.2%), improving access to more economic generation
- Supports the MISO Midwest subregion by reducing price separation across the subregions and decreasing system cost to serve load
- Facilitates a more economical dispatch for MISO Midwest resulting in $8.1B in Adjusted Production Cost (APC) savings
- Provides a robust regional backbone supporting 115.7 GW of Future 2A resource enablement

Congestion Measure

Transmission congestion is quantified through "Congestion Measure" ($/MW) and is calculated by multiplying annual Average Shadow Price ($/MW/hr) by Binding Hours (hr/yr). A reduction in Congestion Measure demonstrates that the most congested transmission constraints in a region have been relieved, and that the effects of congestion throughout the region have been reduced.

The Tranche 2.1 portfolio reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5% including:

- West Region sees a 25.5% ($2.0M/MW) reduction in economic congestion
- Central Region sees a 33.9% ($2.0M/MW) reduction in economic congestion
- East Region sees a 31.7% ($0.9M/MW) reduction in economic congestion

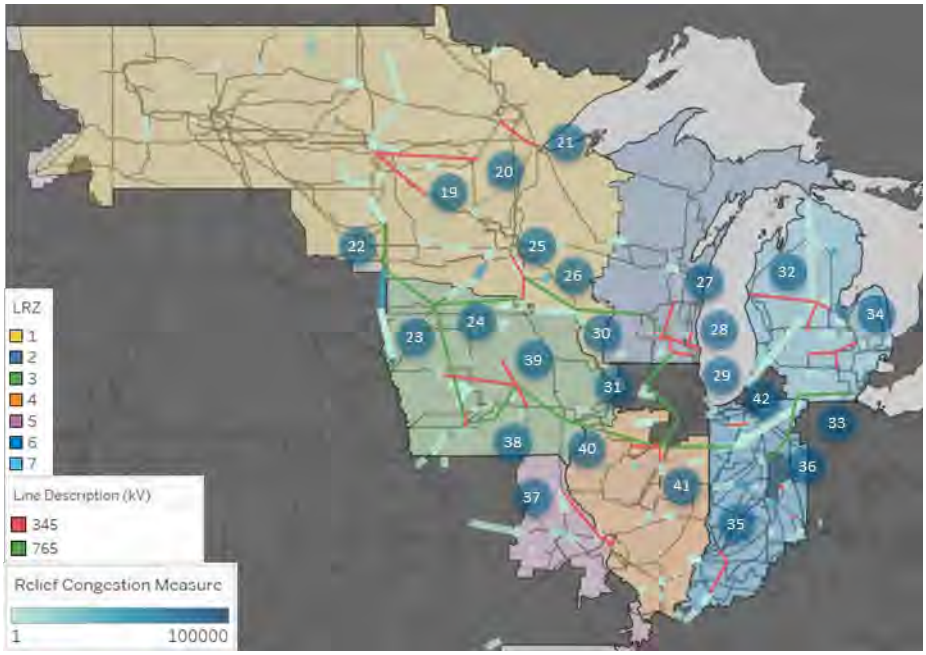


Figure 2.71: Change Case: Year 20 Economic Congestion Relief

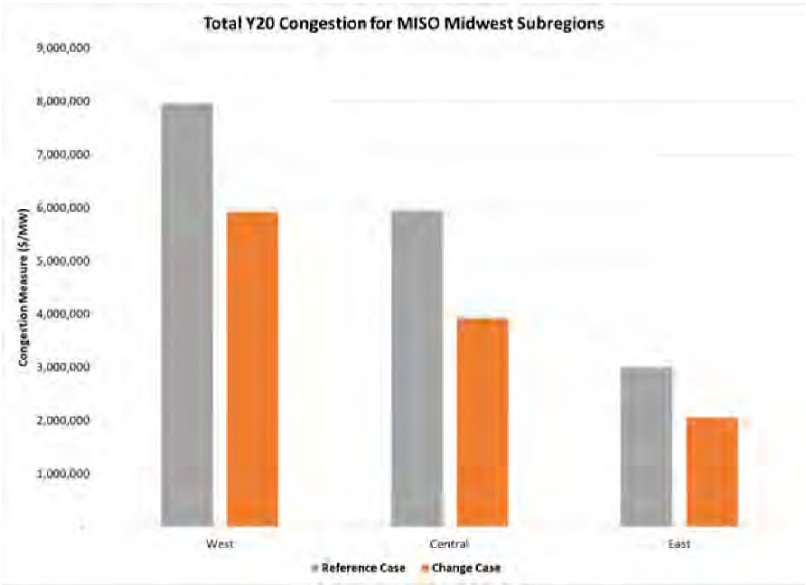


Figure 2.72: Reference and Change Case Year 20 Economic Congestion

MISO Subregion Y20 Congestion Measure by LRZ					
Region	**LRZ**	**Reference Case ($/MW)**	**Change Case ($/MW)**	**Reduction ($/MW)**	**Reduction (%)**
West	LRZ1	6,032,037	5,054,985	977,052	16.2%
	LRZ2	1,109,215	345,145	764,070	68.9%
	LRZ3	811,109	526,642	284,467	35.1%

MISO Subregion Y20 Congestion Measure by LRZ					
Region	**LRZ**	**Reference Case ($/MW)**	**Change Case ($/MW)**	**Reduction ($/MW)**	**Reduction (%)**
	West	7,952,361	5,926,772	2,025,589	25.5%
Central	LRZ4	1,972,466	1,698,381	274,085	13.9%
	LRZ5	1,277,548	563,671	713,877	55.9%
	LRZ6	2,688,959	1,661,564	1,027,395	38.2%
	Central	5,938,973	3,923,616	2,015,357	33.9%
East	LRZ7	3,000,363	2,050,593	949,770	31.7%
	East	3,000,363	2,050,593	949,770	31.7%
MISO Midwest	**Total**	**16,891,697**	**11,900,981**	**4,990,716**	**29.5%**

Table 2.10: Year 20 Congestion Reduction with LRTP Tranche 2.1 by Percentage

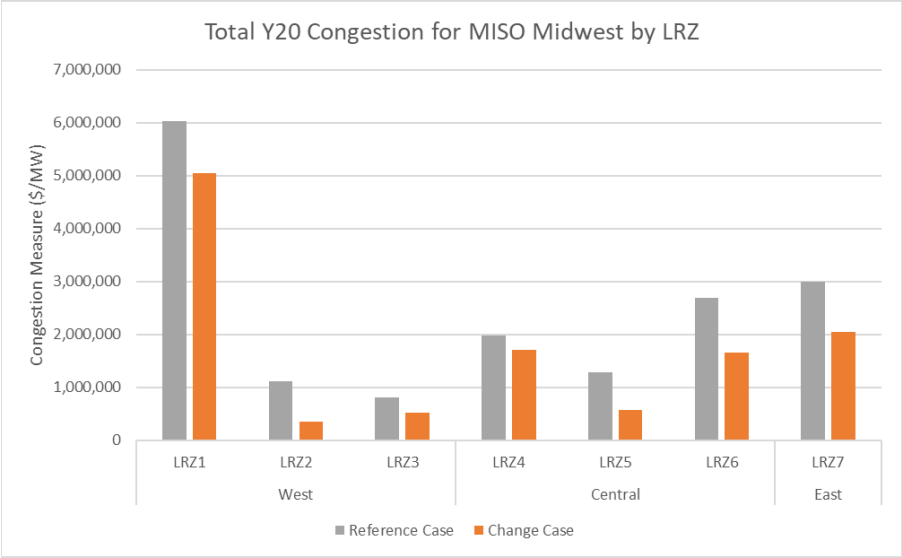


Figure 2.73: Year 20 Congestion with and without LRTP Tranche 2.1 by Local Resource Zone

Curtailment

Curtailment is due to many factors, including congestion and deliverability within MISO Midwest, which are substantially addressed with Tranche 2.1 transmission. Other curtailment is caused by competition and limited interregional export capacity and opportunity, which is outside the scope of this current effort to address.

Between the 2042 Reference case (without Tranche 2.1 transmission) and the 2042 Change case (with Tranche 2.1 transmission), the Tranche 2.1 portfolio reduces curtailment and improves access to more economic generation.

Curtailment in PROMOD is a measure of the available energy from renewable resources which are unable to deliver due to transmission constraints. Curtailment relief demonstrates the Tranche 2.1 portfolio will boost deliverability of additional generation, facilitate the Future 2A fleet change, and drive APC lower by reducing purchase and sales costs.

The Tranche 2.1 portfolio reduces generation curtailment across the MISO Midwest subregion 11.2% (27.1M MWh) including:

- West Region sees a 16.1% (31.6M MWh) reduction in curtailment
- Central Region sees marginal increase in curtailment, primarily due to increased competition from dispatch of more economical units within the Midwest subregion
- East Region sees marginal increase in curtailment, primarily due to increased competition from dispatch of more economical units within the Midwest subregion
- Overall, curtailment for the MISO Midwest subregion reduces from 33.7% to 29.9% in Year 20.

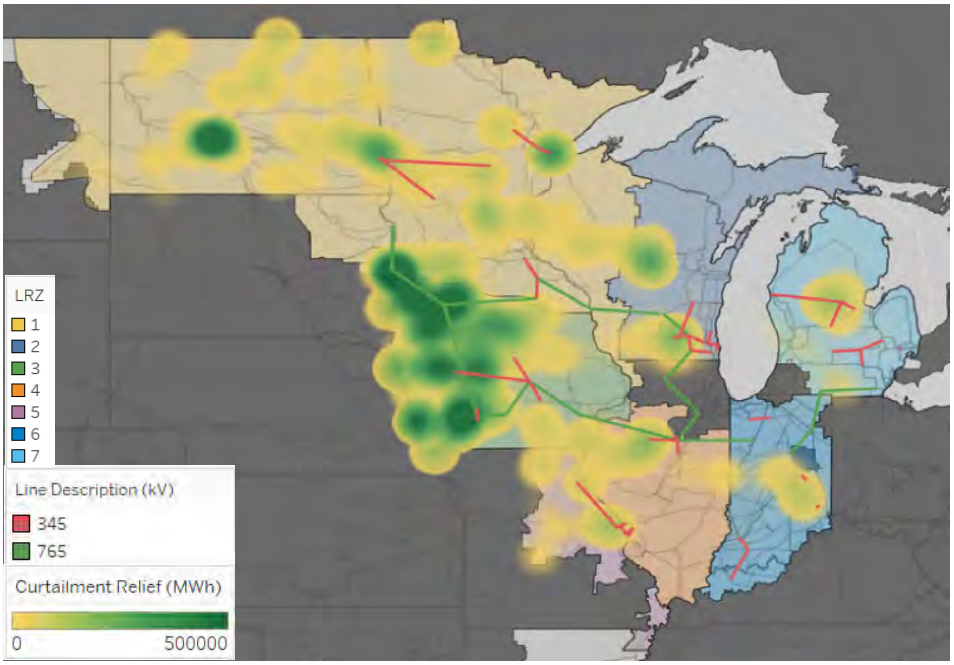


Figure 2.74: Change Case: Curtailment Energy Relief

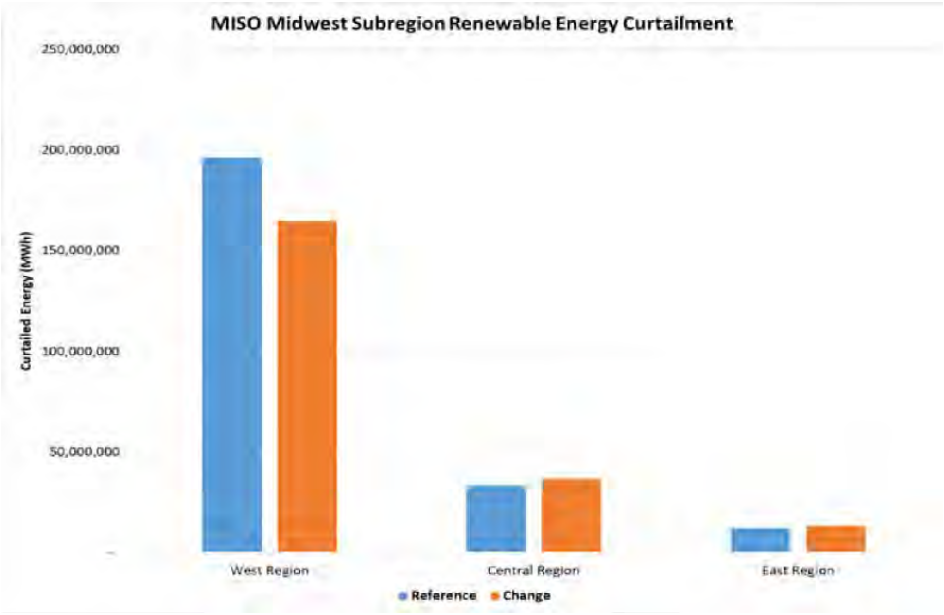


Figure 2.75: Reference and Change Case: Year 20 Curtailment Energy

Load Weighted Locational Marginal Price (Load LMP)

The portfolio supports the MISO Midwest subregion by reducing price separation across the subregion and decreasing system cost to serve load. Cost to serve load is represented by Load Weighted LMP ($/MWh). The difference in prices between portions of the MISO Midwest subregion indicates that transmission constraints are limiting the efficient dispatch of lower cost resources. With Tranche 2.1 transmission included, the separation between these regions' prices decreases. Load Weighted LMPs decrease for each of the West, Central and East regions, with the greatest reductions seen in regions where Reference case prices are the highest.

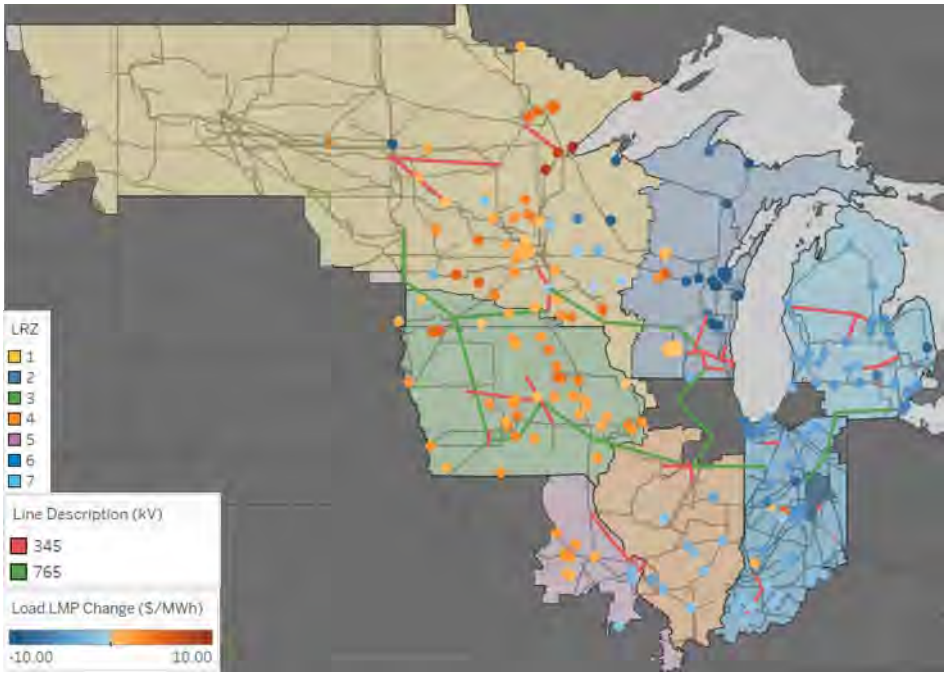


Figure 2.76: Change Case: Load LMP Price Reduction

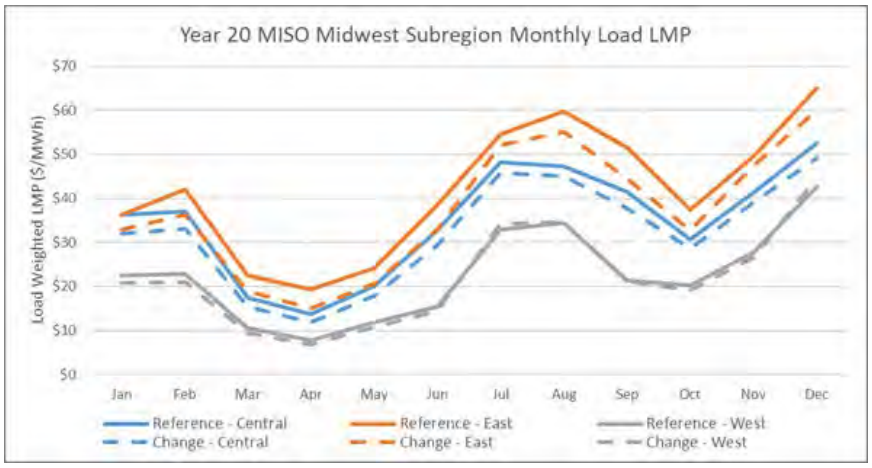
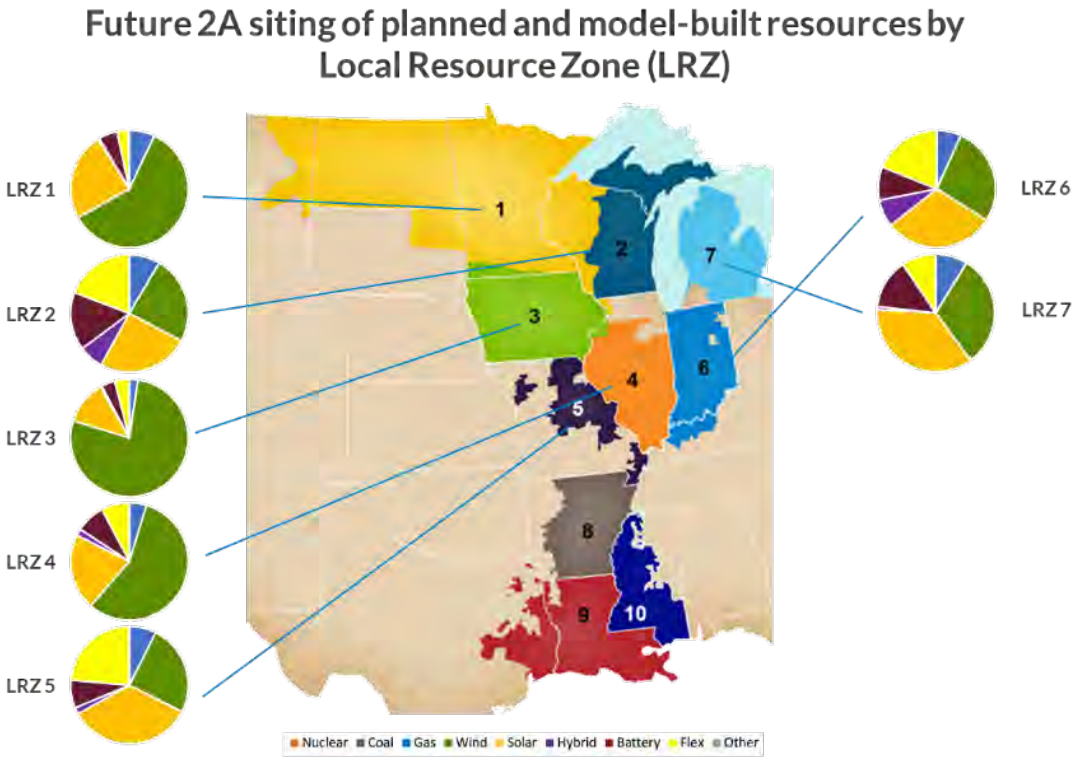


Figure 2.77: Reference & Change Case: Year 20 Load LMP Price

Generation Enablement

Tranche 2.1 provides a robust regional backbone supporting 115.7 GW of Future 2A resource enablement in addition to the 20.1 GW of generation previously enabled with Tranche 1 transmission. To date, the MISO Long Range Transmission Plan Tranche's support 135.8 GW of resource enablement.



Generation Enabled by Resource Type (GW)	
Storage	15.4
Gas & Flex	16.9
Solar	14.1
Hybrid	1.2
Wind	68.1
Total	**115.7**

Generation Enabled by Local Resource Zone (GW)	
LRZ 1	32.1
LRZ 2	9.5
LRZ 3	27.4
LRZ 4	16.1
LRZ 5	2.8
LRZ 6	16.6
LRZ 7	11.2
Total	**115.7**

Figure 2.78: LRTP Tranche 2.1 Future 2A Generation Enablement

West Region – Reliability and Economic Results

Results of transmission solutions in the West Region include the following:

- The Northern Minnesota group provides outlets to North Dakota generation, resolves constraints in this area and connects to Tranche 1 lines
- Congestion in Northern Minnesota is reduced
- Increased generation outlets in North Dakota, South Dakota and Minnesota shift congestion to new flowgates, which are addressed through underbuild
- The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support
- The Minnesota-Wisconsin West – Wisconsin East project adds power transfer capability into load centers in Minnesota and Wisconsin
- Congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network
- The Wisconsin-Illinois 765 kV project assists serving load centers in the region and provides contingency support by connecting to the West – East 765 kV path through Iowa and Illinois

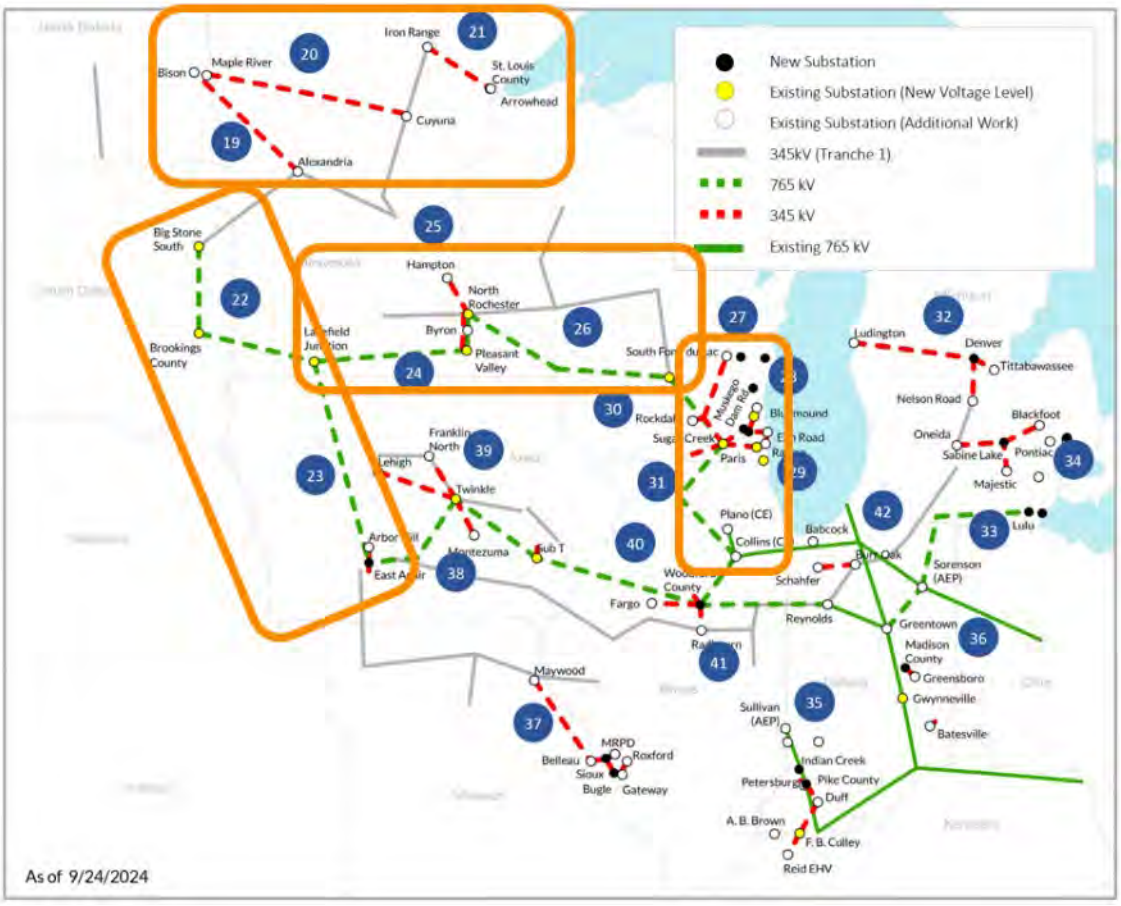


Figure 2.79: West Region Project Groups

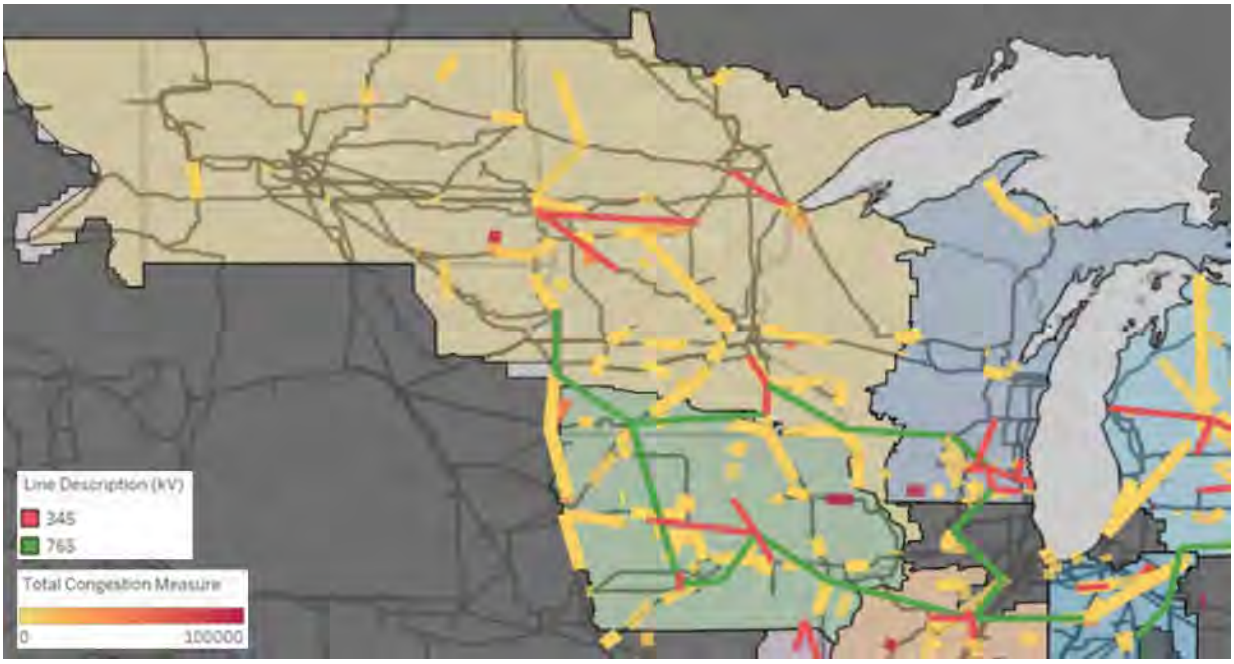


Figure 2.80: Change Case Economic Congestion - West

LRZ 1 – North Dakota and Minnesota

The LRTP Tranche 2.1 portfolio resolves most of the reliability violations on all voltage levels. The Tranche 2.1 portfolio reduces curtailments in LRZ1 by 13.2 % (15.5 M MWh) as illustrated in Figure 2.82 and reduces congestion throughout LRZ1 by 16.2% (977 k$/MW). The curtailment reductions are seen in the areas of greatest base case curtailment, which can be seen in Figure 2.83. Based on the identification of relieved constraints, 32.1 GW of generation is enabled in LRZ 1.

The load serving costs annual Load LMP, moves towards a regional norm, as regional transmission better connecting west and east regions allows a more efficient dispatch of resources (cost to serve load is represented by Load Weighted LMP ($/MWh)). This narrows the MISO Midwest subregion price disparity with a slight increase of $1.87/MWh. Transmission enables greater access for generator exports, allowing renewable generation to offset higher cost generation in other regions. While overall congestion in LRZ1 decreases, generation enabled by new transmission shifts some congestion to new flowgates. The constraints that see increased congestion due to these shifts are associated with more localized issues, or with individual loads or generators and may be better resolved through annual MTEP reliability planning and the generator interconnection processes.

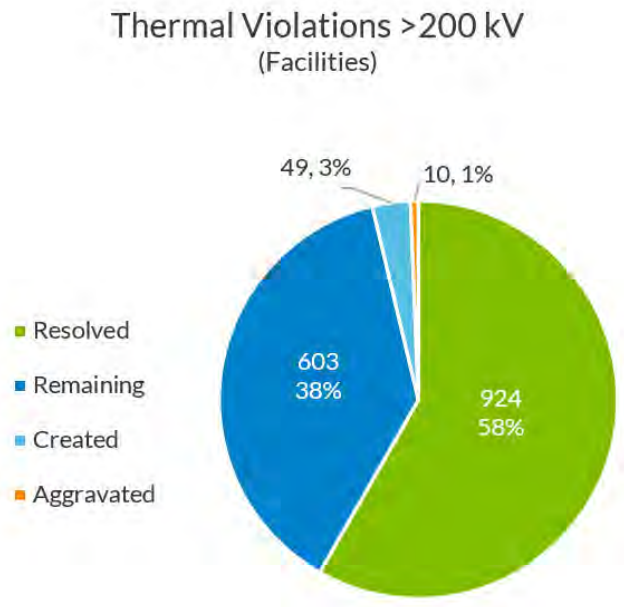


Figure 2.81: Thermal constraint resolution for LRZ1

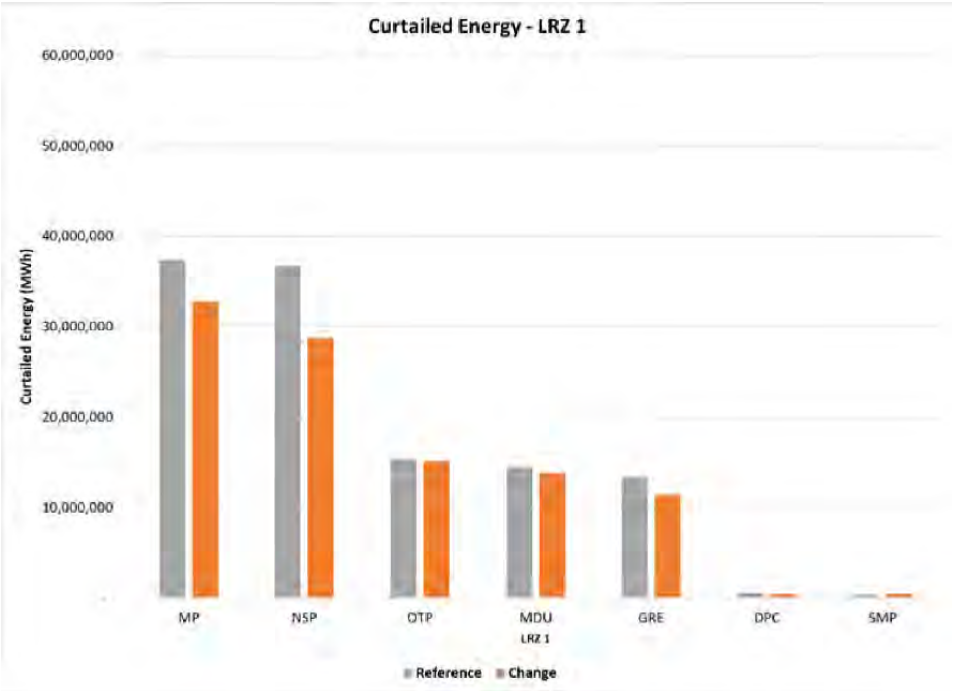


Figure 2.82: Curtailed Energy - LRZ 1

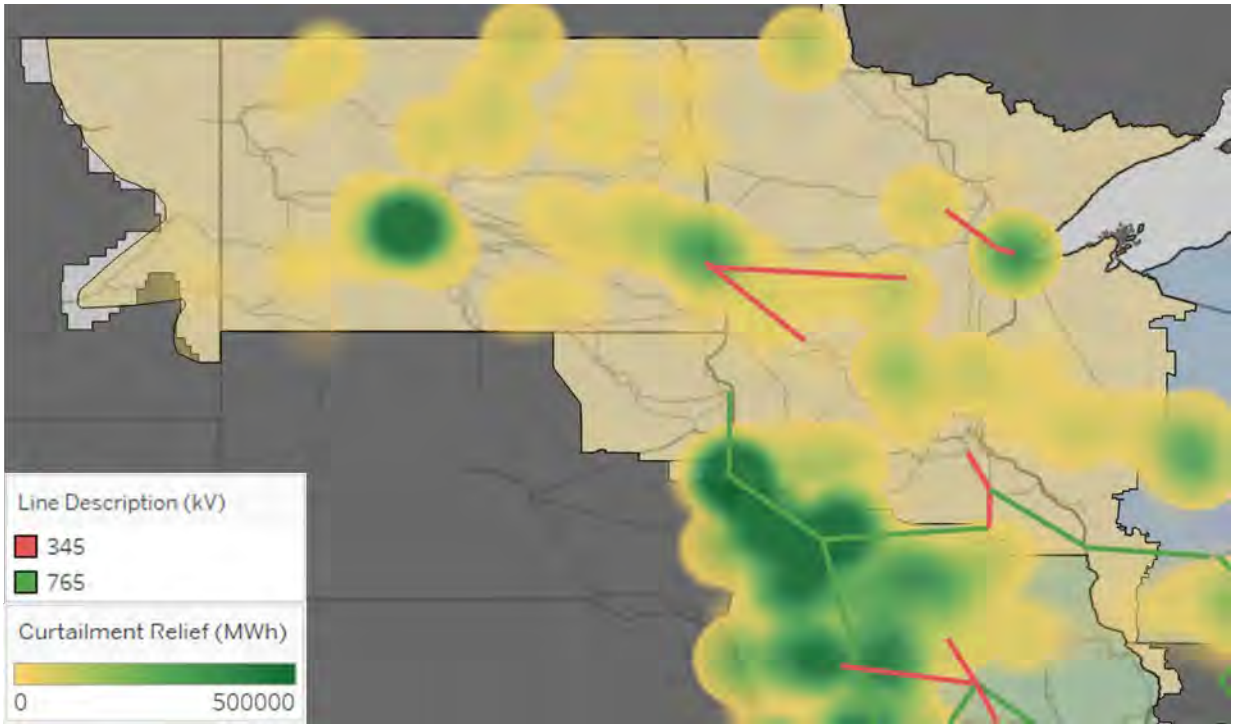


Figure 2.83: Change Case Curtailment Relief – LRZ 1

Bison - Alexandria 345 kV (Project 19), Maple River - Cuyuna 345 kV (Project 20), and Iron Range – St. Louis County - Arrowhead 345 kV (Project 21)

The 345 kV projects in Northern Minnesota (indicated by the dashed red lines in the map below) resolve more than 50% of the constraint violations for both the 200 kV above and below systems. The Northern Minnesota group provides outlets to North Dakota generation, resolves constraint violations in this area and connects to Tranche 1 lines. Congestion in Northern Minnesota is reduced and the increased generation outlet in North Dakota, South Dakota and Minnesota shifts congestion to new flowgates, which are addressed with the portfolio.



Figure 2.84: Northern Minnesota LRTP Tranche 2.1 projects

There is a significant reduction in the loadings in Northern Minnesota because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in the table below. The criteria for selecting these lines was a combination of the number of violations resolved as well as the degree of reduction in loadings. The third column shows the highest loading for these elements in the models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The top resolved facilities are also displayed geographically in the figure below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[MP] Badoura-[GRE] Hubbard 230 kV	138	84
2	[GRE] Hubbard–[OTP] Erie Jct 230 kV	121	78
3	[OTP] Erie Jct-[OTP] Audubon 230 kV	124	83
4	[OTP] Wahpeton-[MRES] Fergus Falls 230 kV	124	84
5	[GRE] Silver Lake-[MRES] Fergus Falls 230 kV	107	74
6	[MPC] Maple River–[MPC] Winger 230 kV	124	66
7	[OTP] Wahpeton-[MPC] Frontier 230 kV	110	51
8	[MP] Riverton-[GRE] Wing River 230 kV	123	74

#	Element	Initial Worst Loading %	Final Worst Loading %
9	[GRE] Silver Lake-[GRE] Henning 230 kV	104	68
10	[MP] Hibbard – [MP] Winter St. 115 kV	243	97
11	[MP] Dahlberg – [MP] Stinson 115 kV	211	Reconfigured
12	[XEL] Sheyenne – [WAPA] Fargo 230 kV	130	56
13	[XEL] Sheyenne – [OTP] Maple River 230 kV	114	51
14	[MP] Fairmount Park – [MP] Winter St. 115 kV	259	95
15	[MP] Fairmount Park – [MP] Stinson 115 kV	230	74
16	[OTP] Wilton – [OTP] Scribner 115 kV	126	86
17	[OTP] Wilton Tap – [OTP] Scribner 115 kV	123	86
18	[OTP] Solway – [OTP] Wilton Tap 115 kV	114	81
19	[XEL] Wakefield – [XEL] Stockade Tap 115 kV	111	90
20	[MP] Arrowhead – [MP] Gary 115 kV	123	74

Table 2.11: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota

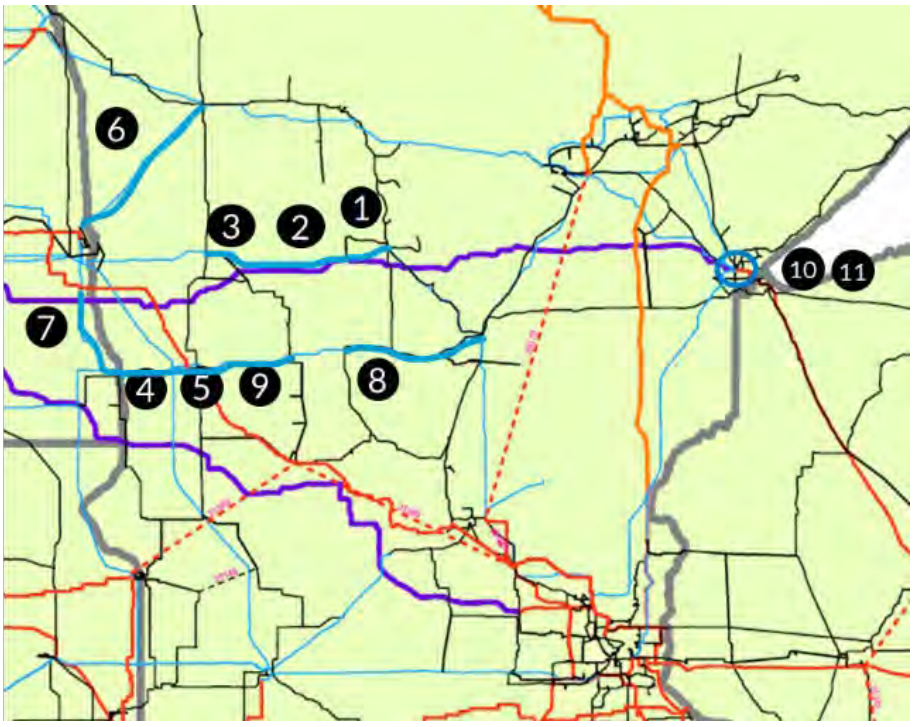


Figure 2.85: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota

Projects in Northern Minnesota increase deliverability of resources from North Dakota, South Dakota and Western Minnesota towards load centers in Northern Minnesota and down towards the Twin Cities. These projects reduce congestion overall, and reduce congestion on the most heavily congested flowgate in LRZ1. The increase in energy delivery shifts the dispatch throughout LRZ1, and some congestion shifts to different flowgates associated with more localized issues. Table 2.12 shows top relieved flowgates ranked by congestion measure relief for projects 19, 20, & 21. The combined congestion measure impact for flowgates assessed for projects 19, 20, & 21 is shown in Figure 2.86.

Y20 Top Relieved Flowgates - Projects 19, 20, & 21			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 1117: [MP] HIBBARD - [MP] WNTR ST 115 kV 1	1,621,984	876,000	745,984
Event 270: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	158,693	-	158,693
Event 192: [MP] LONG PR7 - [GRE] GRE-LTLSKTP7 115 kV 1	454,591	329,864	124,727
Base Case: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	112,246	-	112,246
Event 1033: [MP] AITKNMN7 - [GRE] GRE-AITKIN 7 115 kV 1	47,573	-	47,573
Event 586: [GRE] GRE-INMAN 4 - [GRE] GRE-WINGRIV4 230 kV 1	64,442	24,550	39,892
Event 1355: [MP] CLOQUET7 - [MP] CANOSIA7 115 kV 1	58,902	19,317	39,585
Event 1391: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	38,318	-	38,318
Event 1045: [MP] FLDWDTP7 - [MP] MDWLNDS7 115 kV 1	31,812	-	31,812
Event 592: [NSP] SHEYNNE4 - [OTP] LAKE PARK T4 230 kV 1	40,486	11,028	29,457

Table 2.12: Top Relieved Flowgates – Projects 19, 20 & 21

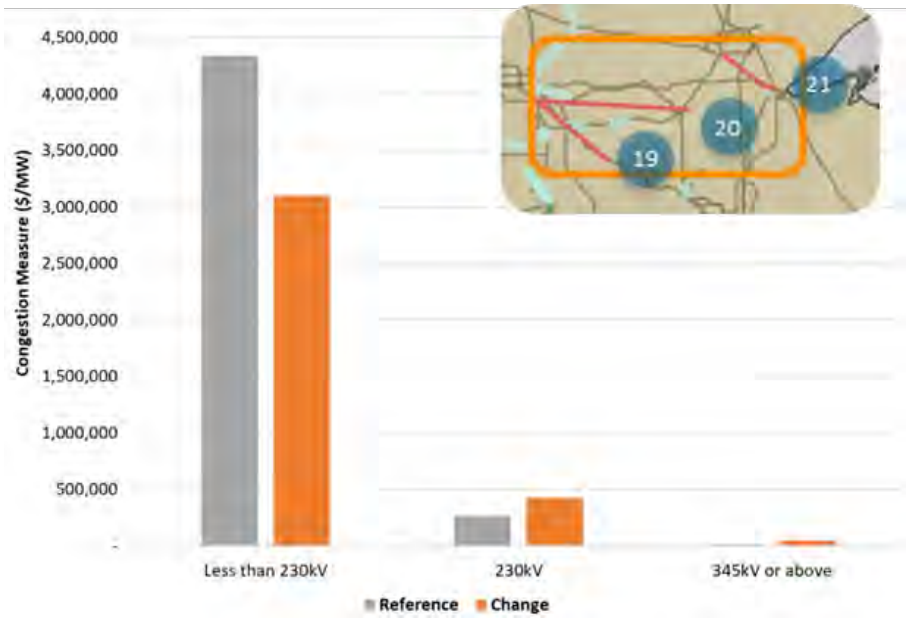


Figure 2.86: Congestion Measure for Projects 19, 20, and 21

Lakefield Junction - Pleasant Valley - North Rochester 765 kV (Project 24), Pleasant Valley - North Rochester - Hampton Corner 345 kV (Project 25), and North Rochester – Columbia 765 kV (Project 26)

The portfolio resolves most constraints in Southern Minnesota and Western Wisconsin, especially on 200 kV and above facilities. The Minnesota -Wisconsin West – Wisconsin East project assists transfer of power into load centers in Minnesota and Wisconsin.

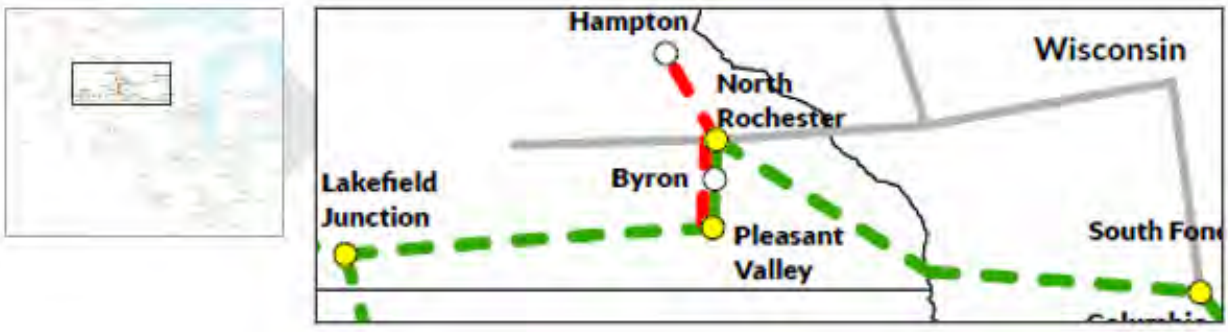


Figure 2.87: Southern Minnesota and Western Wisconsin LRTP Tranche 2.1 projects

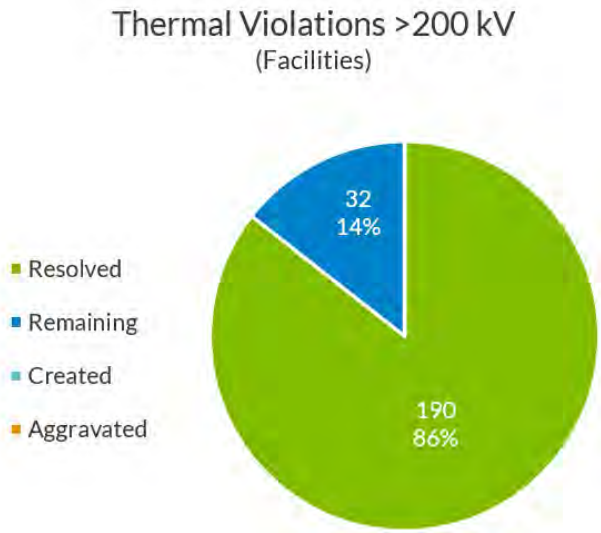


Figure 2.88: Thermal constraint resolution for Southern Minnesota and Western Wisconsin

There is a significant reduction in the loadings in Southern Minnesota and Western Wisconsin because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in the table below. The third column shows the highest loading for these elements in the base models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The North Rochester-Byron and Byron-Pleasant Valley lines, which are labeled as reconfigured, still exist in the portfolio models and have been upgraded to higher ratings as part of a single-to-double circuit rebuild and are no longer overloaded anymore. The locations of the top 10 lines are shown on the map below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[XEL] Helena–[XEL] Hampton Corner 345 kV	162	75
2	[XEL] AS King–[XEL] Eau Claire 345 kV	133	75
3	[XEL] Prairie Island–[XEL] N. Rochester 345 kV	123	90
4	[XEL] Helena–[XEL] Scott Co. 345 kV	127	98
5	[XEL] Wilmarth–[XEL] Crandall 345 kV	123	66
6	[XEL] Wilmarth–[XEL] Sheas Lake 345 kV	113	81
7	[XEL] N. Rochester–[XEL] Byron 345 kV	110	Reconfigured
8	[XEL] Helena–[XEL] Sheas Lake 345 kV	105	72
9	[XEL] Eau Claire–[ALTE] Arpin 345 kV	116	71
10	[XEL] Byron–[XEL] Pleasant Valley 345 kV	114	Reconfigured
11	[XEL] Wilmarth–[XEL] Huntley 345 kV	108	73
12	[XEL] Tremval – [MGE] North Madison 345 kV	112	67
13	[XEL] Jump River – [WPS] Gardner Park 345 kV	108	67
14	[ALTW] Emery – [MEC] Floyd 161 kV	120	83
15	[MP] Gordon – [MP] Hawthorne Tap 161 kV	135	22
16	[ALTW] Barton – [ALTW] Lime Creek 161 kV	121	91
17	[WPS] Cassel – [WPS] Wien 115 kV	130	79
18	[XEL] Minnesota Valley – [XEL] Redwood Falls 115 kV	125	82
19	[WPS] Sunnyvale – [WPS] Cassel 115 kV	134	79
20	[DPC] Wabaco – [DPC] Kellogg 161 kV	151	96

Table 2.13: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

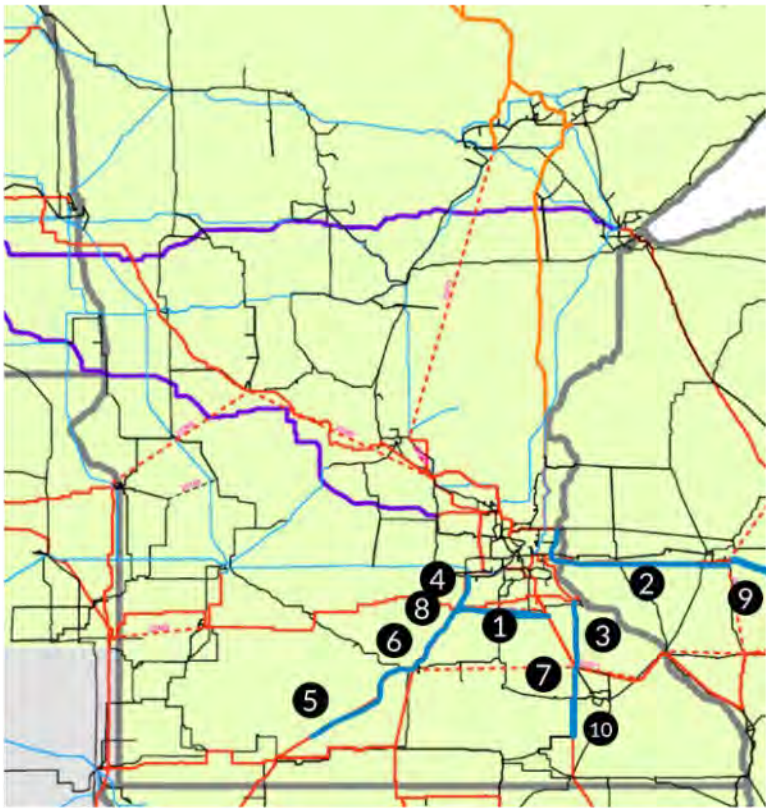


Figure 2.89: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

Projects in Southern Minnesota and Wisconsin enable substantially more renewable delivery, particularly from the Eastern Dakotas, Southwestern Minnesota, and Northern Iowa – locations with some of the strongest wind resources. This is aided through the loop configuration of the other Tranche 2.1 765 kV west-to-west path which increases the amount of power that can reliably flow over 765 kV facilities. Overall congestion in this area remains flat even as energy delivery increases. The additional enabled resources shift the patterns of congestion to new and different flowgates. Table 2.14 shows top relieved flowgates ranked by congestion measure relief for projects 24, 25, and 26. The combined congestion measure impact for flowgates assessed for projects 24, 25, and 26 is shown in Figure 2.90.

Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Top Relieved Flowgates	**Congestion Measure ($/MW)**		
	Reference	**Change Case**	**Total Relief**
Event 130: [SMP] RUTLAND5 - [ALTW] FOX LK 5 161 kV 1	85,064	720	84,343
Event 146: [NSP] BLUE LK3 - [NSP] SCOTTCO3 345 kV 1	49,404	13,732	35,672
Event 32: [NSP] BLUE LK3 - [NSP] HMPT CNR3 345 kV 1	55,518	26,597	28,922
Event 587: [ALTW] BARTON5 - [ALTW] LIME CK L2 5 161 kV 1	34,899	15,532	19,367
Event 143: [NSP] ADAMS 3 345kV - [ALTW] ADAMS 5 161 kV 9	26,860	8,666	18,194
Base Case: [DPC] ALMA 5 - [DPC] KELLOGG 5 161 kV 1	18,347	1,254	17,093

Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Event 1443: [NSP] WILMART3 - [ALTW] HUNTLEY3 345 kV 1	10,423	50	10,372
Event 255: [NSP] BRIGGS RD 5 - [NSP] TREMVAL5 161 kV 1	5,248	210	5,038
Event 250: [MEC] WEBSTER5 - [MEC] SUB T FD 5 161 kV 1	4,729	0	4,729
Event 78: [NSP] WILMART3 - [NSP] SHEAS LK3 345 kV 1	4,807	188	4,619

Table 2.14: Top Relieved Flowgates – Projects 24, 25, & 26

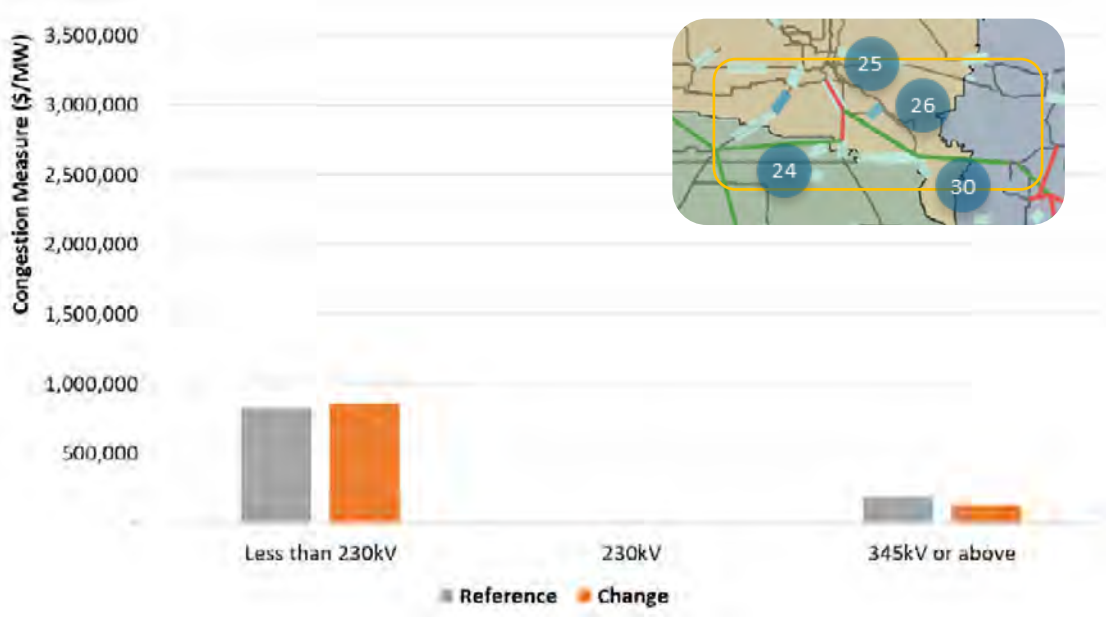


Figure 2.90: Congestion Measure for Projects 24, 25, and 26

LRZ 2 – Wisconsin

The LRTP Tranche 2.1 portfolio resolves a vast majority of the thermal violations across all voltage levels in LRZ2. The Tranche 2.1 portfolio reduces congestion throughout LRZ2 by 68.9% (764 k$/MW) and reduces curtailments in LRZ2 by 26.9% (1.4M MWh) enabling 9.5 GW of generation. Load serving costs decrease year-round and throughout LRZ2, by an average of $7.67 / MWh as shown in Figure 2.93.

Reductions in curtailment follow the geographic pattern of initial curtailment and are observed in corridors relieved by the 765 kV regional path, seen in Figure 2.92. The 765 kV pathway moves regional flows off lower voltage facilities, supports economic congestion reduction and significantly relieves top binding constraints. Congestion in LRZ2 is driven by regional loop flow, which is more easily relieved through 765 kV paths. The Tranche 2.1 facilities reduce congestion due to loop flow and access to additional lower cost renewables in the West. Increased access to low-cost resources from neighboring LRZs significantly reduces Load LMPs.

Thermal violations remaining on >200 kV facilities are a result of splitting of the existing lines, and their overloads are less severe than the original overloads. For example, some of the new violations are attributed to the splitting of two lines. The highest loading on one of the lines was 156% in the core models and decreased to 109% in the portfolio models. Similarly, the other facility was loaded at 119% in the core

models and decreased to 102% in the portfolio models. The 345/230 kV transformers are fully relieved in the core models, and the new violations are limited to the transfer scenarios specific to new resource units to load and it is more appropriate for these issues to be addressed by the annual MTEP reliability planning and the generator interconnection processes.

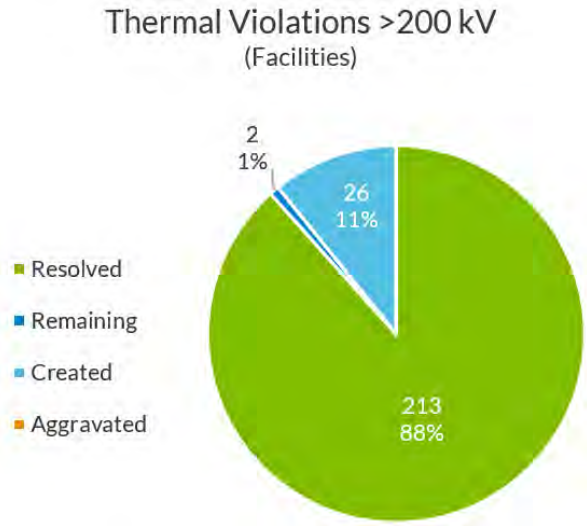


Figure 2.91: Thermal constraint resolution for LRZ2

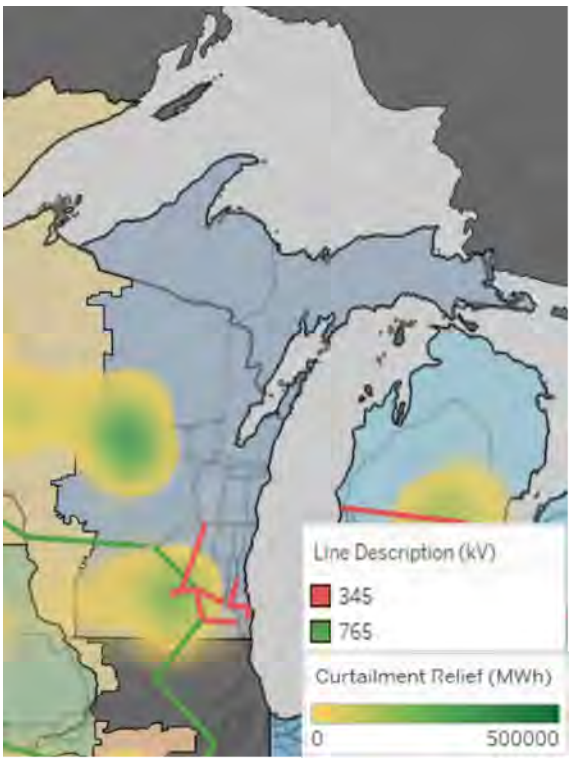


Figure 2.92: Change Case: Curtailment Relief for LRZ 2

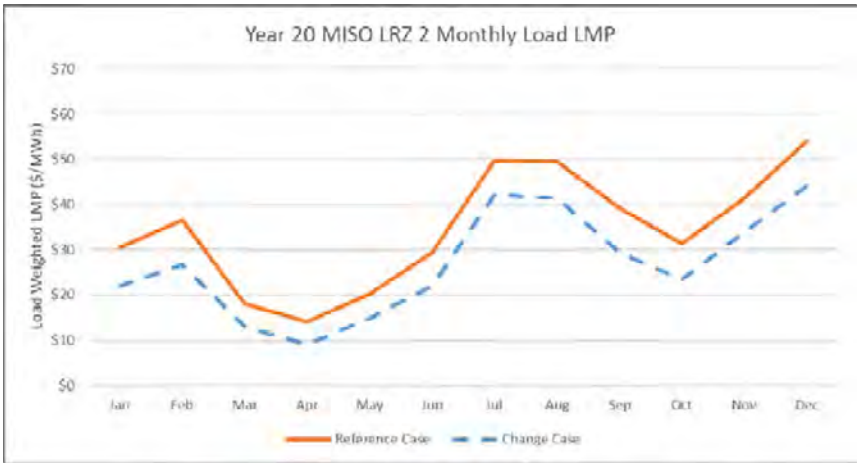


Figure 2.93: Comparison: Monthly Load LMP for LRZ 2

Rocky Run – Werner West - North Appleton 345 kV (Project 27), South Fond du Lac – Jefferson - Rockdale and Big Bend - Sugar Creek - Kitty Hawk 345 kV (Project 28), Bluemond - Arcadian -– Muskego Dam Road - Elm Road - Racine 345 kV and Arcadian – Waukesha 138 kV uprate (Project 29), Columbia - Sugar Creek 765 kV (Project 30), and Sugar Creek - Collins 765 kV (Project 31)

The Tranche 2.1 portfolio resolves a majority of the thermal violations across all voltage levels in Southeastern Wisconsin. Congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network. Sugar Creek – Collins 765 kV project in Wisconsin and Illinois assists in serving load centers in the region and provides contingency support by connecting the northern 765 kV path to the West – East 765 kV corridors through Iowa and Illinois.

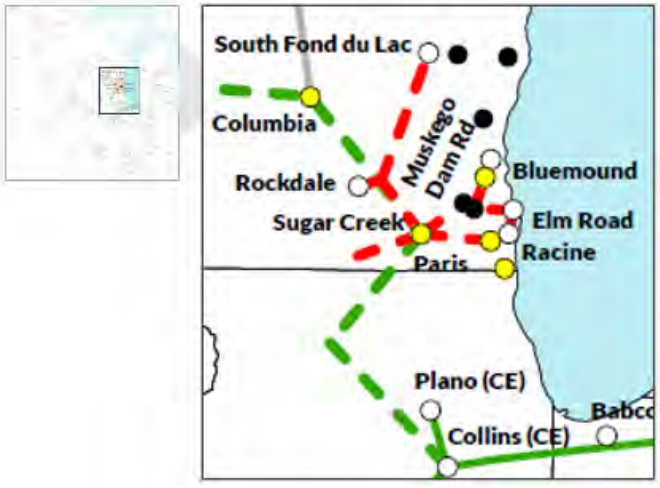


Figure 2.94: Southeastern Wisconsin LRTP Tranche 2.1 projects

Loading stress on several elements across various voltage levels in this region is relieved by the Tranche 2.1 portfolio. The elements with the most reduction in the loadings are shown in the table below. "Reconfigured" means that the circuits have been cut into two or more segments, because of new stations added in between, and thus such circuits no longer exist in the cases with the portfolio.

- The Cypress – Arcadian 345 kV line is now the Cypress - Sheboygan River - Cedar Creek Junction – Arcadian 345 kV line
- The Edgewater - S Fond du Lac 345 kV line is now the Edgewater - Mullet River Junction - Sheboygan River - S Fond du Lac 345 kV line
- The Zion Station - Pleasant Prairie 345 kV line is now Zion Station - Lakeview - Pleasant Prairie 345 kV line
- The Arcadian – Paris – Zion Station e 345 kV line is now Arcadian – Big Bend - Muskego Dam Rd - Elm Rd - Racine - Mt Pleasant - Pleasant Prairie 345 kV line
- The Arcadian – Pleasant Prairie 345 kV line is now the Arcadian – Big Bend – Muskego Dam Road – Paris – Lakeview – Pleasant Prairie 345 kV line.

The map below depicts the top relieved facilities from the table.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[WPS] Rocky Run–[WEC] Werner W. 345 kV	201	56
2	[WEC] Werner W.-[WEC] N. Appleton 345 kV	192	48
3	[WEC] Cypress–[WEC] Arcadian 345 kV	156	Reconfigured
4	[ALTE] Edgewater–[ALTE] S. Fond du Lac 345 kV	119	Reconfigured
5	[WEC] Cypress-[WEC] Forest Jn. 345 kV	138	77
6	[WEC] Cedar Sauk-[ALTE] Edgewater 345 kV	121	56
7	[WPS] Rocky Run–[WPS] Gardner Park 345 kV	113	86
8	[CE] Wempletown-[ALTE] Paddock 345 kV	105	75
9	[CE] Zion Station-[WEC] Pleasant Prairie 345 kV	103	Reconfigured
10	[WEC] Arcadian-[WEC] Pleasant Prairie 345 kV	112	Reconfigured
11	[CE] Zion Energy Center-[WEC] Pleasant Prairie 345 kV	117	52
12	[WEC] Elk Lake Reactor – [WEC] Elkhart Lake 138 kV	148	92
13	[ALTE] N. Lake Geneva – [ALTE] Elkhorn 138 kV	115	93
14	[WEC] Auburn – [WEC] Butternut 138 kV	121	87
15	[ALTE] Sunrise – [WEC] Lakehead 138 kV	117	74
16	[ALTE] Nelson Dewey 161/138 kV Transformer	134	97
17	[WEC] Elkhart Lake – [WEC] Saukville 138 kV	148	80
18	[WEC] Forest Junction – [WPS] Tecumseh Rd 138 kV	122	77
19	[WEC] Esker View – [WPS] Tecumseh Rd 138 kV	122	70
20	[WEC] PM - [WEC] Esker View 138 kV	119	66

Table 2.15: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Eastern Wisconsin

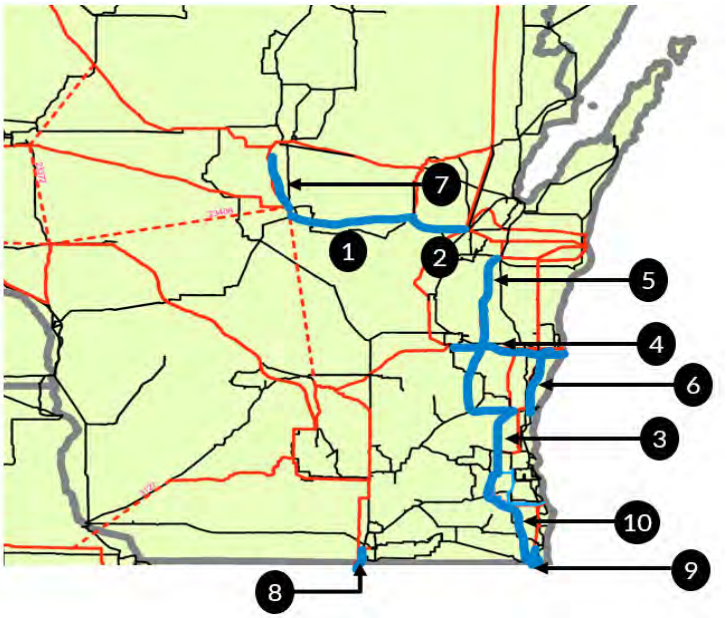


Figure 2.95: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southeastern Wisconsin

The regional backbone projects in and through Wisconsin are successful in moving regional flows off of the local system and onto the backbone transmission, which results in the relief of the majority of congestion seen in LRZ2. The most congested flowgate in LRZ2 is fully relieved by these projects. This congestion relief also allows LRZ2 resources to dispatch more efficiently, reducing curtailment in the zone. Table 2.16 lists the top flowgates relieved by projects 27, 28, 29, 30, and 31 in LRZ 2. Figure 2.96 shows the combined impact for all flowgates assessed with projects 27, 28, 29, 30, and 31.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 27, 28, 29, 30, & 31			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**Reference**	**Change Case**	**Total Relief**
Event 1463: [WPS] ROCKY RUN - [WEC] WERNER W B4 345 kV 1	292,658	-	292,658
Event 94: [ALTE] NLG 138 - [ALTE] ELK 138 138 kV 1	123,330	790	122,541
Base Case: [WEC] JEFRSN5 - [WEC] CRWFSH R 138 kV 1	142,777	29,873	112,904
Event 47: [WEC] BRLGTN1 - [WEC] NLK GV T 138 kV 1	48,790	211	48,579
Base Case: [ALTE] ROE 138 - [WEC] LKHD_CAM_TP 138 kV 1	36,426	-	36,426
Event 22: [UPPC] SILVER RIVER - [UPPC] GREENSTN TAP 138 kV 1	89,452	58,211	31,241
Event 75: [ALTE] NLG 138 - [ALTE] ELK 138 138 kV 1	20,300	398	19,902
Event 361: [UPPC] SILVER RIVER - [UPPC] GREENSTN TAP 138 kV 1	43,144	24,512	18,632
Event 615: [UPPC] PERCH LK - [MIUP] PRESQ IS4567 138 kV 1	36,357	19,733	16,624
Event 92: [WEC] BCR_LNG_TAP - [WEC] BLUFFCRK 138 kV 1	14,126	-	14,126

Table 2.16: Top Relieved Economic Flowgates – Projects 27, 28, 29, 30, & 31



Figure 2.96: Congestion Measure for Projects 27, 28, 29, 30, & 31

LRZ 3 – Iowa

The LRTP Tranche 2.1 portfolio resolves a vast majority of the thermal violations in LRZ 3. For the <200 kV system, 92% of the violations have been resolved with 80% of the violations resolved on the >200 kV system as shown in the two pie charts below. Congestion shown in the reference case is reduced by the LRTP Tranche 2.1 portfolio by 35.1% (284 k$/MW). The strongest economic congestion relief is observed in the West to East oriented elements in Central Iowa and Southern Minnesota. Smaller increases in economic congestion are in Western Iowa, and numerous smaller shifts of congestion are seen as transmission enables Future 2A generation.

The LRTP Tranche 2.1 portfolio reduces curtailments by 20.0% (14.6M MWh) which is demonstrated in Figure 2.99 and enables 27.4 GW of generation. Reduced curtailment generally matches the geography of reference case curtailment, with the largest concentration in Northern and Western Iowa as can be observed from Figure 2.98. Transmission enables greater access for generator exports, reducing costs for purchasing companies. Load LMPs increase slightly by $2.52/MWh, moving towards a regional norm, while narrowing the MISO Midwest subregion price disparity. Overall congestion in LRZ is reduced, as backbone transmission picks up more regional flows.

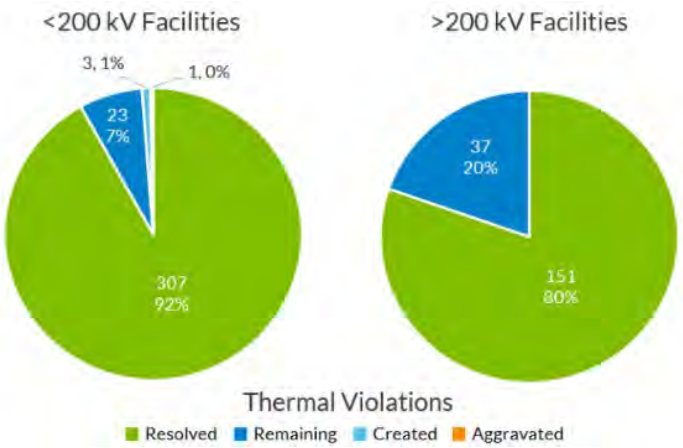


Figure 2.97: Pie- charts showing LRTP Tranche 2.1 resolving a vast majority of thermal violations in LRZ 3

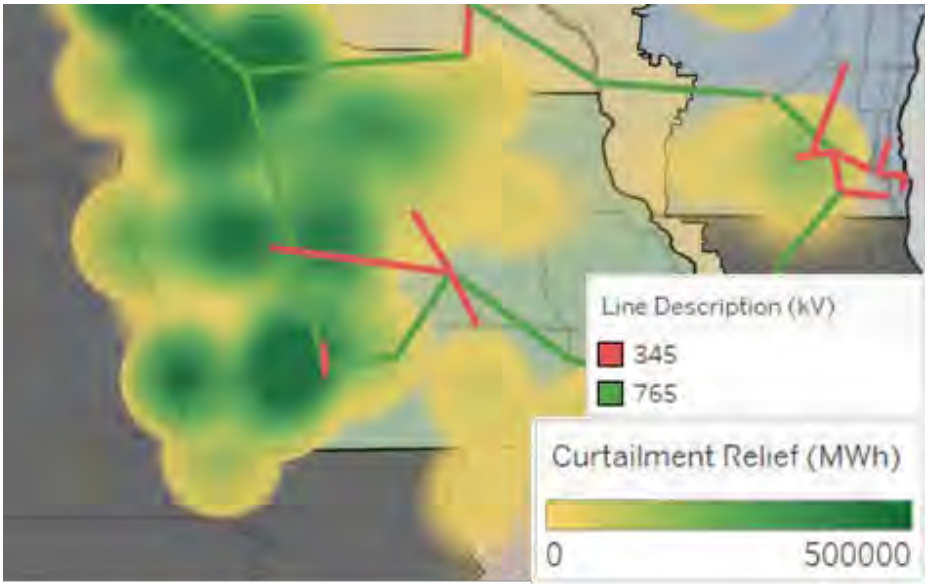


Figure 2.98: Change Case Curtailment Relief – LRZ 3

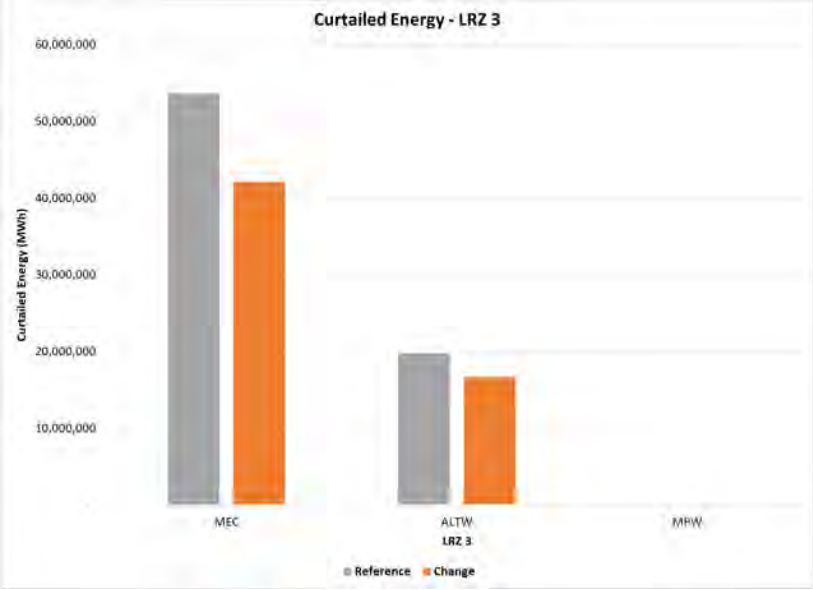


Figure 2.99: Curtailed Energy - LRZ 3

Big Stone South - Brookings County - Lakefield Junction765 kV (Project 22) & Lakefield Junction - East Adair 765 kV (Project 23)

The 765 kV project in northeastern South Dakota , Southwestern Minnesota and Western Iowa provides outlet for generation in South Dakota and also connects both 765 kV west-to-east paths together at the western end to provide contingency support. The reliability impacts of LRTP Tranche 2.1 portfolio, and the Big Stone South- Brookings County- Lakefield Junction -East Adair 765 kV projects have been studied in this section.

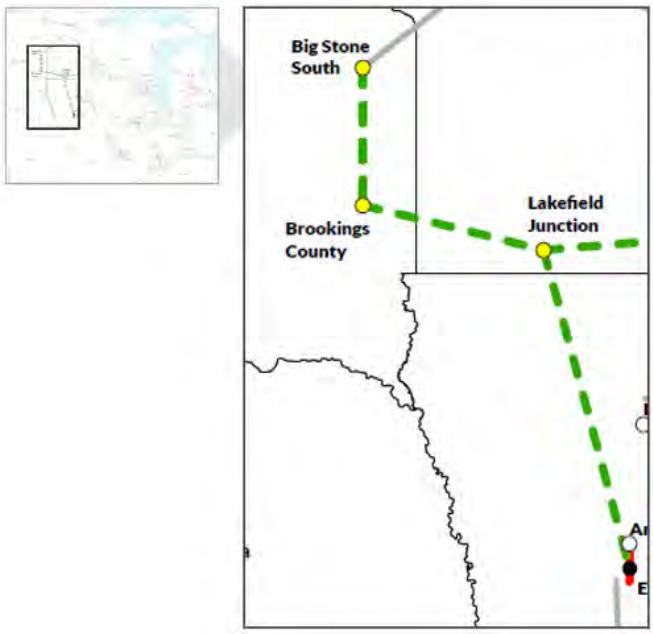


Figure 2.100: South Dakota, Southwestern Minnesota, and Western Iowa LRTP Tranche 2.1 projects

The LRTP Tranche 2.1 portfolio solved the majority of the thermal violations (82%) for the 200 kV+ system as shown below in the pie-chart below. A large number of the unresolved thermal violations for the 200 kV and below facilities are due to local generation siting, and can be better addressed through the annual MTEP reliability planning and the generator interconnection processes.

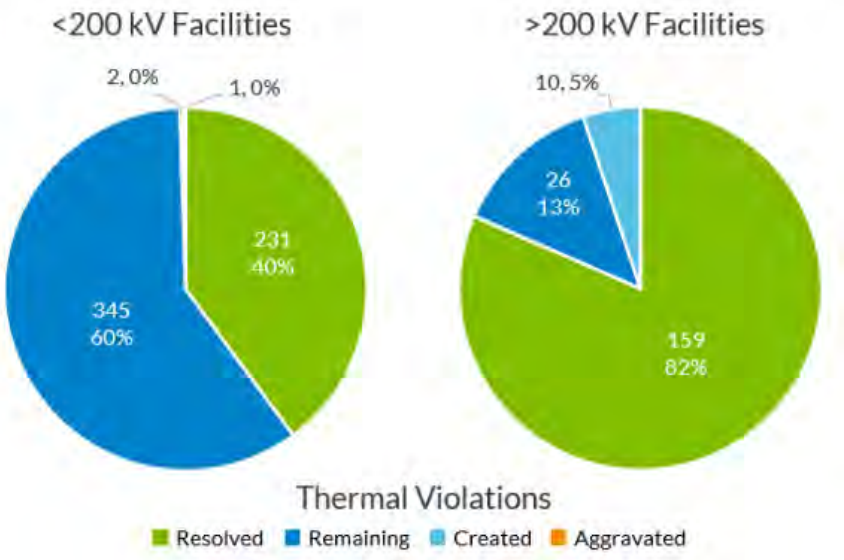


Figure 2.101: Pie-charts showing majority of thermal violations on the 200 kV and above facilities in South Dakota, Southwestern Minnesota, and Western Iowa being resolved by the LRTP Tranche 2.1 portfolio

The table below shows the top twenty limiting elements in the area that had the most impactful resolution in their thermal violations upon portfolio application, the map shows the geographic location of the top

facilities. The elements with overloading as high as 150% across all models and all seasons/scenarios in the pre-portfolio had loading level drop to less than 100% upon application of the portfolio. Notably among them is the Raun- Ida County West 345 kV line which was loaded at 142% of its rated capacity in the Light Load 2042 case. The same element had loading drop to 48% for the Light Load 2042 case upon application of the Tranche 2.1 portfolio.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[GRE] Panther-[XEL] McLeod 230 kV	121	81
2	[XEL] Minnesota Valley-[GRE] Panther 230 kV	114	76
3	[XEL] Minnesota Valley-[WAPA] Granite Falls 230 kV	116	75
4	[XEL] Hazel Creek 345/230 kV transformer	112	74
5	[XEL] Split Rock–[WAPA] White 345 kV	122	92
6	[MEC] Raun–[MEC] Ida County West 345 kV	142	48
7	[NPPD] Tekamah -[MEC] Raun 161 kV	147	83
8	[MEC] Raun–[OPPD] Sub 3451 345 kV	114	46
9	[MEC] Ida County West–[MEC] Ida County 345 kV	123	24
10	[AEPW] Southern Hills–[MEC] Booneville 345 kV	109	74
11	[XEL] Swan Lake-[XEL] Stockade Tap 115 kV	108	77
12	[XEL] Split Rock 230/115 kV transformer	119	53
13	[GRE] Kerkhoven Tap-[GRE] Kerkhoven 115 kV	117	77
14	[XEL] Split Rock- [WAPA] Sioux Falls 230kV	143	63
15	[XEL] McLeod 230/115 kV transformer	120	98
16	[XEL] Coon Creek- [XEL] Moore Lake 115 kV	100	97
17	[OTP] Benson-[OTP] Danvers 115 kV	106	77
18	[XEL] Monticello-[GRE] Oakwood 115 kV	103	99
19	[XEL] Brookings County 345/115 kV transformer	113	92
20	[OTP] Formal 230/115 kV transformer	107	99

Figure 2.102: Top reliability constraints resolved by LRTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

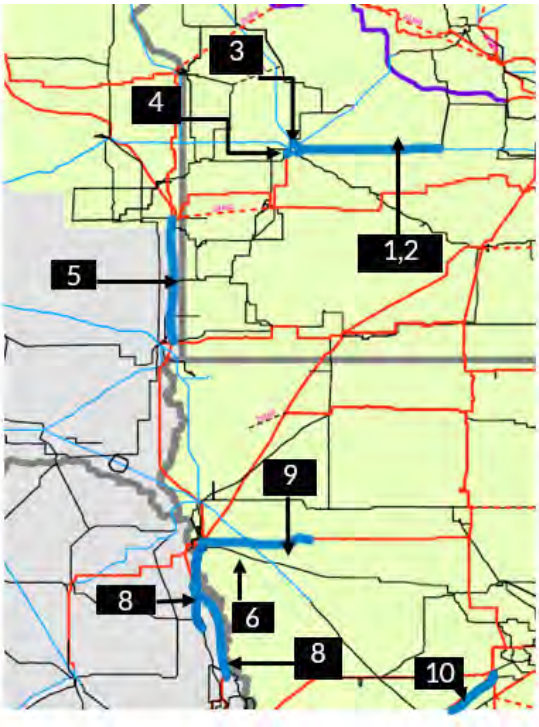


Figure 2.103: Top reliability constraints resolved by LRTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

The LRTP Tranche 2.1 portfolio significantly reduces curtailment and increases energy delivery from LRZ3. The increase in energy delivery shifts the dispatch, with relieved congestion in the western portion of LRZ3 being offset by congestion from new flowgates, many of which represent more localized issues. While the total congestion in the western portion of Iowa slightly increases, congestion throughout LRZ3 decreases, due to the combined contribution of the other transmission backbone system elements. Table 2.17 shows top relieved flowgates ranked by congestion measure relief for projects 22 and 23. The combined congestion measure impact for flowgates assessed for projects 22 and 23 is shown in Figure 2.104.

Y20 Top Relieved Flowgates - Projects 22 & 23			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 42: [NSP] HUC-MCLEOD 4 230 kV - [OTP] HUC-MCLEOD 7 115 kV 1	239,742	114,971	124,771
Base Case: [OTP] BIGSTON4 230kV - [OTP] YBUS770 100 kV 2	15,099	0	15,099
Event 43: [NSP] HUC-MCLEOD 4 230kV - [OTP] HUC-MCLEOD 7 115 kV 1	8,200	-	8,200
Event 392: [OTP] HANKSON4 - [OTP] FORMAN 4 230 kV 1	5,781	-	5,781
Event 53: [OTP] BIGSTON4 - [OTP] BROWNSV4 230 kV 1	6,444	2,873	3,570
Event 375: [MEC] RAUN 3 - [OPPD] S3451 3 345 kV 1	7,970	4,681	3,289
Event 171: [MEC] RAUN 3 - [OPPD] S3451 3 345 kV 1	4,817	2,877	1,940
Base Case: [NSP] BRKNGCO3 345kV - [NSP] BRKNGCO7 115 kV 9	2,068	329	1,739

Y20 Top Relieved Flowgates - Projects 22 & 23			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 45: [OTP] BIGSTON4 230kV - [OTP] BROWNSV4 230 kV 1	2,767	1,404	1,363
Event 70: [NSP] SPLT RK4 - [WAUE] SIOUXFL4 230 kV 1	2,753	1,499	1,253

Table 2.17: Top Relieved Economic Flowgates – Projects 22 & 23

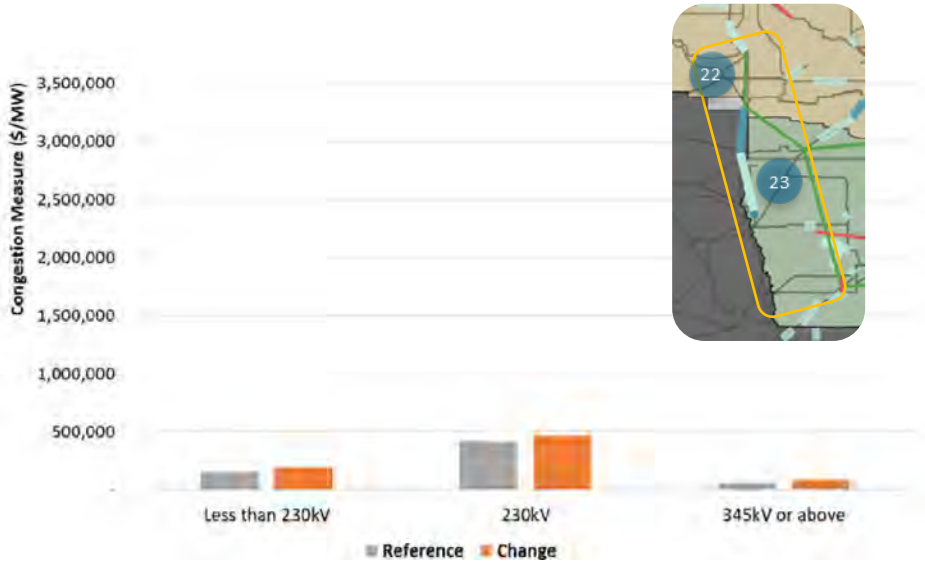


Figure 2.104: Congestion Measure for Projects 22, 23

Central Region – Reliability and Economic Results

- Both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7
- Transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. The 345 kV project in Missouri resolves numerous constraints in the St. Louis Metro region and enables increased intraregional transfers across the Central Region
- The Southern Indiana/Western Kentucky 345 kV project resolves constraints in the region and enhances West – East transfer capacity across the Central Region
- East Central Indiana upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the Indiana load centers in Central and Southeastern Indiana

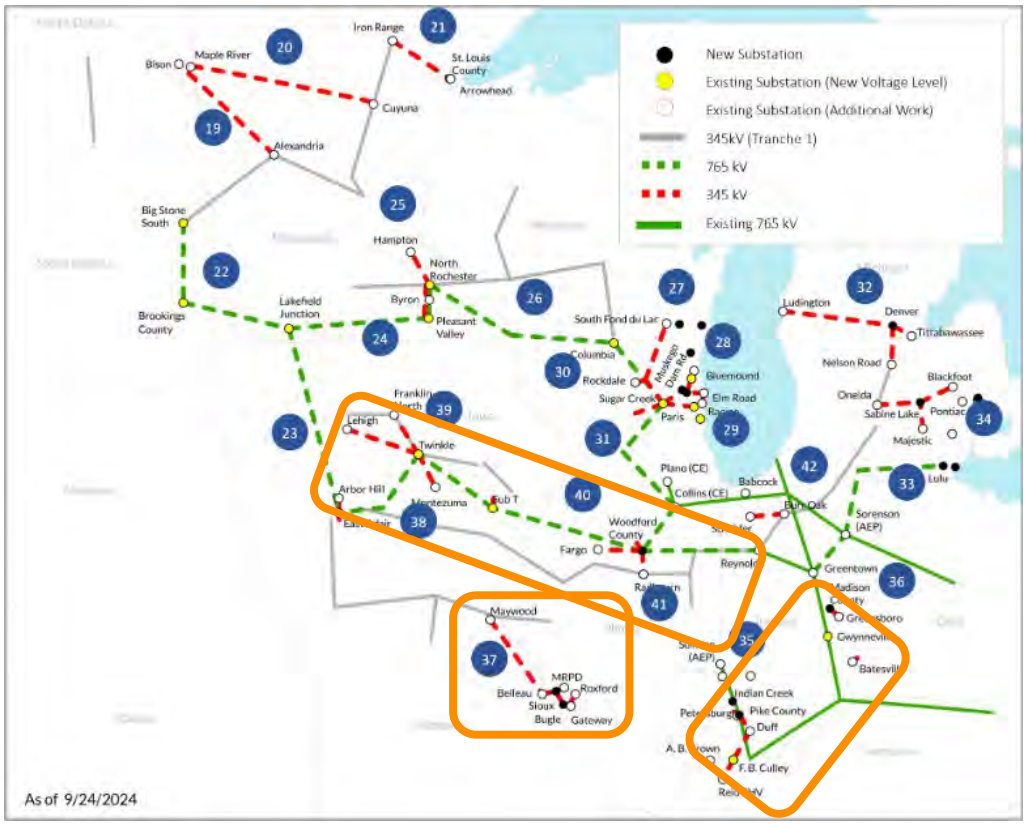


Figure 2.105: Central Region Project Groups

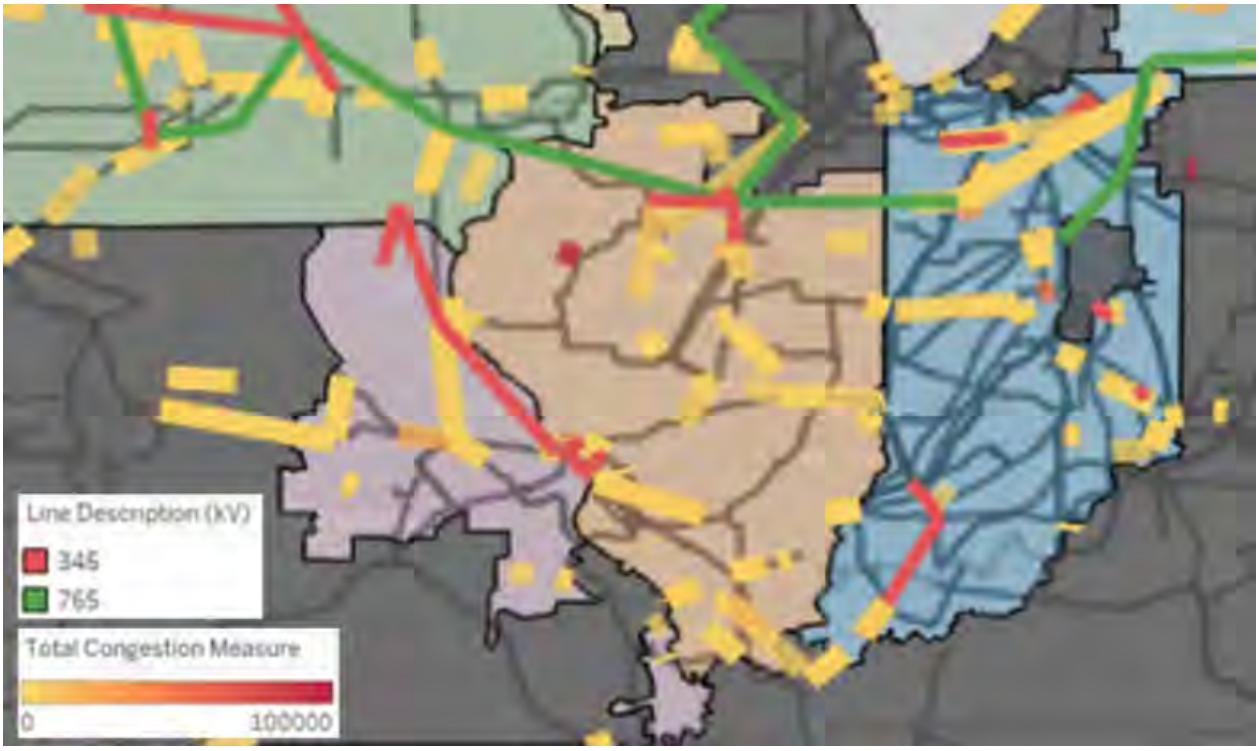


Figure 2.106: Change Case Economic Congestion - Central

LRZ 4 – Illinois

The Tranche 2.1 portfolio resolves most thermal violations on 200 kV and above facilities in LRZ4. For the <200 kV system, more than 50% of thermal violations are resolved. The Tranche 2.1 portfolio reduces congestion in LRZ4 by 13.9% (274 k$/MW) – shown in Figure 2.109 – and enables 16.1 GW of generation in LRZ 4. Load serving costs decrease year-round and throughout LRZ4, by an average of $1.90 / MWh, which is demonstrated in Figure 2.109. Increased exports through transmission expansion allows renewable generation to offset higher cost generation in LRZ4.

Increased access to low cost resources enabled throughout the MISO Midwest subregion drives down Load LMPs in LRZ4 . Curtailment, increased by 1.5M MWh. Change is mainly driven by increased competition with lower cost enabled generation throughout the region. Relief of regional constraints shifts congestion to more localized constraints, resulting in overall reduction in congestion. The remaining under 200 kV reliability issues are specific to local generation or load and may be better resolved through annual MTEP reliability planning and the generator interconnection processes.

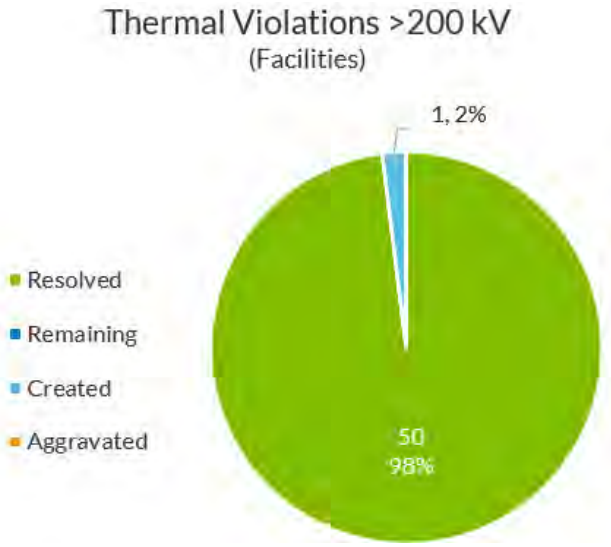


Figure 2.107: Thermal constraint resolution for LRZ4

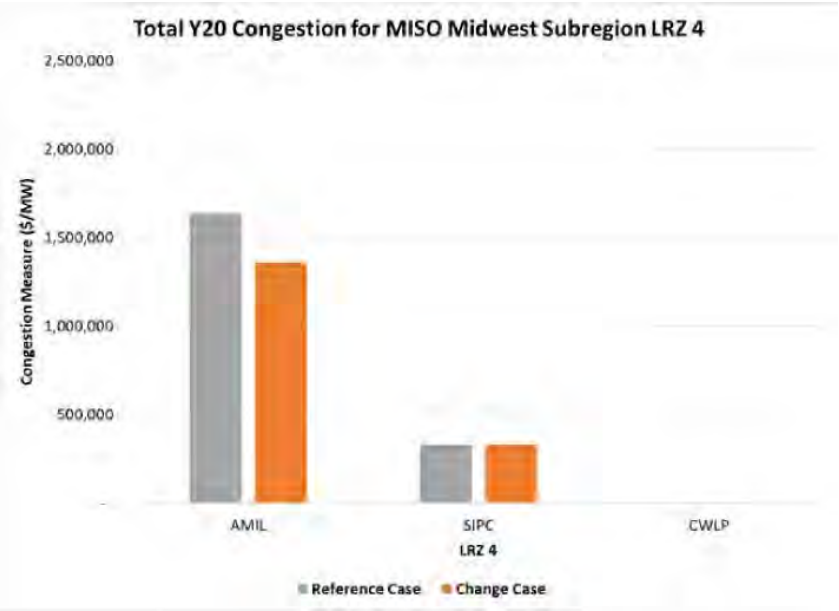


Figure 2.108: Congestion Measure – LRZ 4

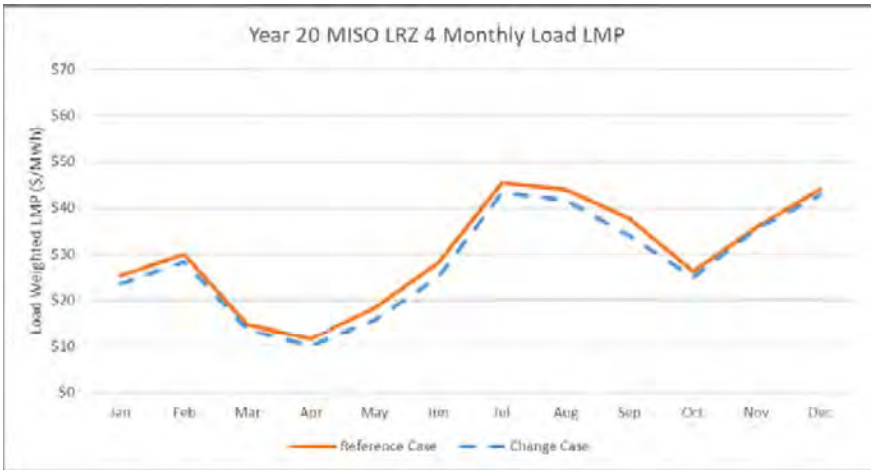


Figure 2.109: Comparison: Monthly Load LMP – LRZ 4

East Adair - Marshalltown - Sub T 765 kV (Project 38), Lehigh - Marshalltown - Franklin North & Montezuma - Marshalltown 345 kV (Project 39), Sub T - Woodford County - Collins & Woodford County - Reynolds 765 kV (Project 40), and Woodford County - Fargo & Woodford County - Radbourn 345 kV (Project 41)

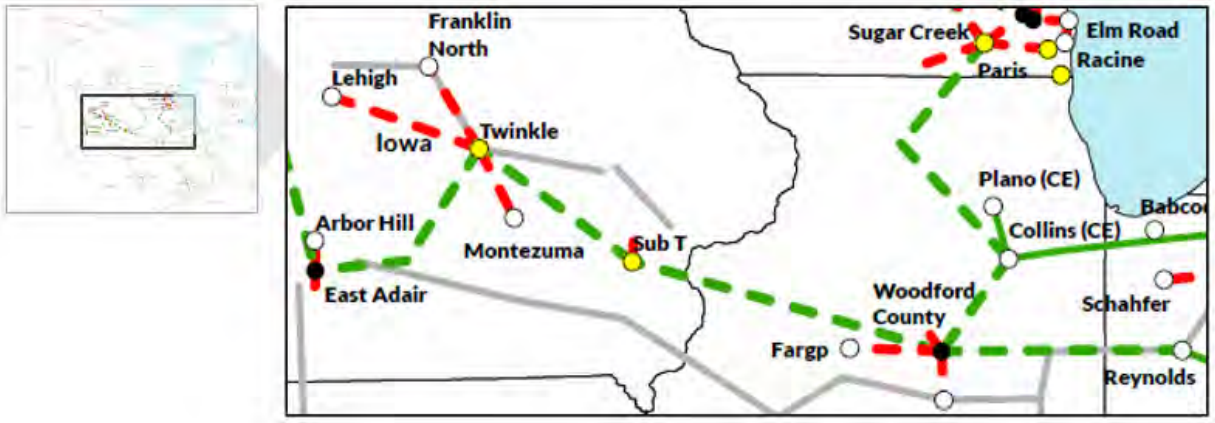


Figure 2.110: Central Iowa and, Illinois and Northern Indiana LRTP Tranche 2.1 projects

Both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7. Transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. Various violations in Central IA and IL are alleviated with the 765 kV facility connecting the western IA 765 to the Indiana 765 kV system. The regional backbone significantly relieves multiple 345 kV facilities while providing transfer capability to various load centers. The top alleviated facilities are in the table and the map shows the top 10 from the list.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[ALTW] Hazleton - [ALTW] Arnold 1 345 kV	125	69
2	[MEC] Bondurant- [MEC] Montezuma 1 345 kV	110	56
3	[MEC] Grimes - [MEC] Beaver Crk 1 345 kV	115	60
4	[MEC] Oak Grove - [AMMO] Sub 93 1 345 kV	108	58
5	[MEC] Webster - [MEC] LeHigh 1 345kV	144	62
6	MEC] Morgan Valley - [MEC] TIffin 1 345 kV	103	56
7	[AMIL] Tazewell-[AMIL] Maple Ridge 345 kV Ckt 1	143	65
8	[AEP] Eugene – [AMIL] Bunsonville 345 kV	101	81
9	[AMIL] Tazewell-[AMIL] Maple Ridge 345 kV Ckt 2	141	65
10	[AMIL] Sandburg-[AMIL] Mercer 161 kV	115	69
11	[ALTW] Lasalle – [ALTW] Mitchell County 345 kV	105	57
12	[ALTW] Lasalle – [ALTW] Hazelton 345kV	110	60
13	[MEC] Walcott - [MEC] Sub 92 345kV	105	48
14	[MEC] Hills - [MEC] Sub T 345kV	112	32
15	[AMIL] Hines – [AMIL] Pioneer 138 kV	165	73
16	[ALTW] Hazelton – [ALTW] Dundee 138 kV	124	72
17	[ALTW] Liberty – [ALTW] Dundee 138 kV	115	67
18	[AMIL] Fargo 345 kV - [AMIL] Fargo 138 kV Xfmr 1	134	36
19	[AMIL] Fargo 345 kV - [AMIL] Fargo 138 kV Xfmr 2	134	36
20	[NIPSCO] Sheffield – [NIPSCO] Wolf Lake	107	97

Figure 2.111: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

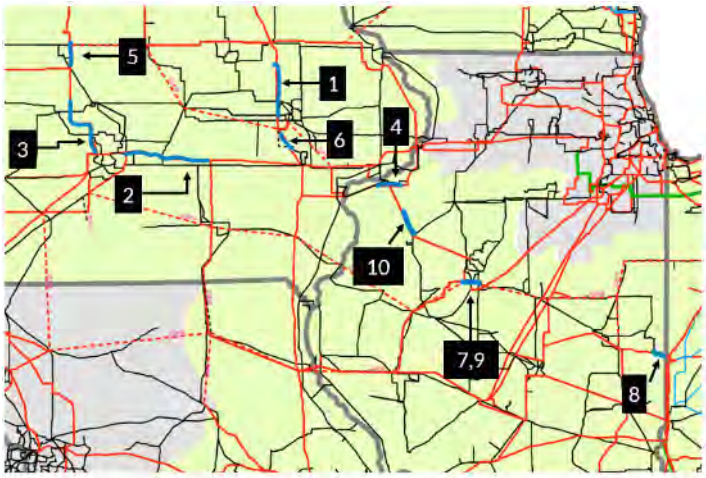


Figure 2.112: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

The corridor of projects between Central Iowa and Northern Indiana supports a more robust exchange of low-cost resources across this region, and from net exporting regions like LRZ3. This results in lower prices in LRZ4. Overall congestion measure is seen to decrease in LRZ4 and along this corridor, with reductions on West/East oriented elements at a wide range of voltage levels. Figure 2.18 shows top relieved flowgates ranked by congestion measure relief for projects 38, 39, 40,and 41. The combined congestion measure impact for flowgates assessed for projects 38, 39, 40, and 41 is shown in Figure 2.113.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 38, 39, 40 & 41			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Base Case: [AEP] 05ALBION - [NIPS] 17NORTHPORT 138 kV 1	908,179	633,175	275,004
Event 660: [AMIL] 7TAZEWELL - [AMIL] 7MAPLE RIDGE 345 kV 2	216,702	13,734	202,968
Event 3: [DUK-IN] 08WABASH_RIV 345kV - [DUK-IN] 08WAB R 230 kV 1	173,755	11,961	161,794
Event 62: [ALTW] HAZLTON L2 5 - [ALTW] DUNDEE 5 161 kV 1	273,853	148,901	124,952
Event 395: [DUK-IN] 08CHRYS3 - [DUK-IN] 08KOKOMO 138 kV 1	220,813	123,911	96,902
Event 62: [ALTW] LIBERTY5 - [ALTW] DUNDEE 5 161 kV 1	86,730	40,931	45,798
Event 1301: [AMIL] 7TAZEWELL - [AMIL] 7MAPLE RIDGE 345 kV 1	46,211	2,008	44,203
Event 63: [MEC] BONDURANT3 - [MEC] MONTEZUMA 3 345 kV 1	34,589	-	34,589
Base Case: [COMED] MAZON; R - [AMIL] 4CORBIN 138 kV 1	30,507	2,956	27,551
Event 108: [DUK-IN] 08CUYSUB - [DUK-IN] 08CUYUGA 345 kV 1	42,624	18,530	24,094

Table 2.18: Top Relieved Economic Flowgates – Projects 38, 39, 40, & 41



Figure 2.113: Congestion Measure - Projects 38, 39, 40, & 41

LRZ 5 – Missouri

The Tranche 2.1 portfolio resolves all thermal violations for 200 kV and above in LRZ 5. The final portfolio provides relief to the <200 kV system across multiple scenarios. The final portfolio reduces congestion in LRZ 5 by 55.9% (714 k$/MW), shown below in Figure 2.114, by adding another path directly north of congested facilities. The majority of relief comes from the congested [AMMO] Ft Zumwalt-[AMMO] Huster 138 kV line. The new 345 kV line also provides relief to transmission lines facilitating west to east flows.

Load serving costs decrease year-round and throughout LRZ 5, by an average of $2.08 / MWh, as seen in Figure 2.115. Transmission enables greater access to cheaper generation from other parts of the MISO Midwest subregion, and with that increased access and competition, curtailments see minimal change in LRZ 5 (-0.02M MWh). Resolved transmission constraints enable 2.8 GW of generation in LRZ 5.

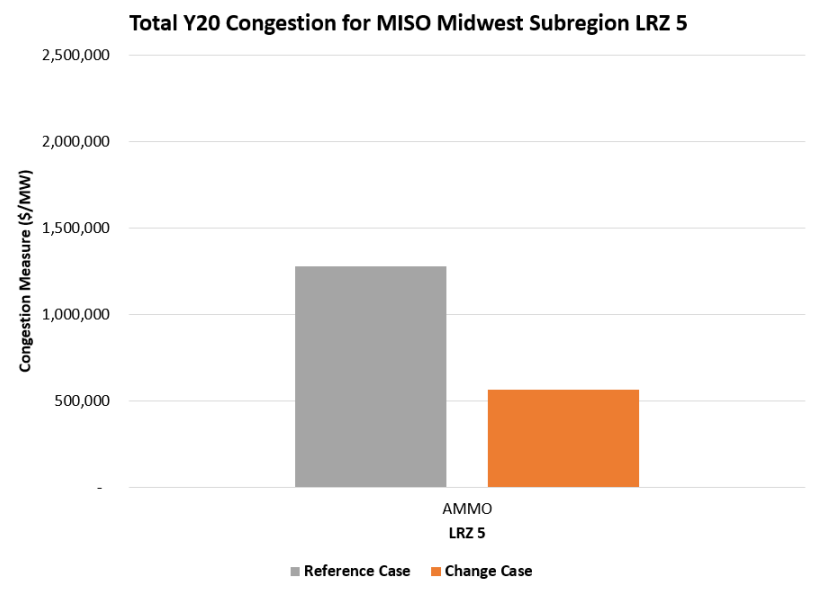


Figure 2.114: Congestion Measure – LRZ 5

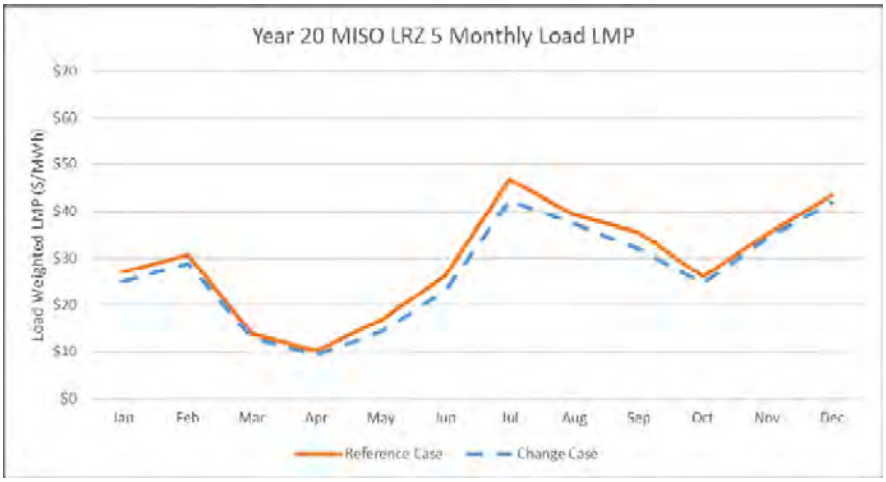


Figure 2.115: Comparison: Monthly Load LMP – LRZ 5

Maywood - Belleau - MRPD - Sioux - Bugle 345 kV (Project 37)

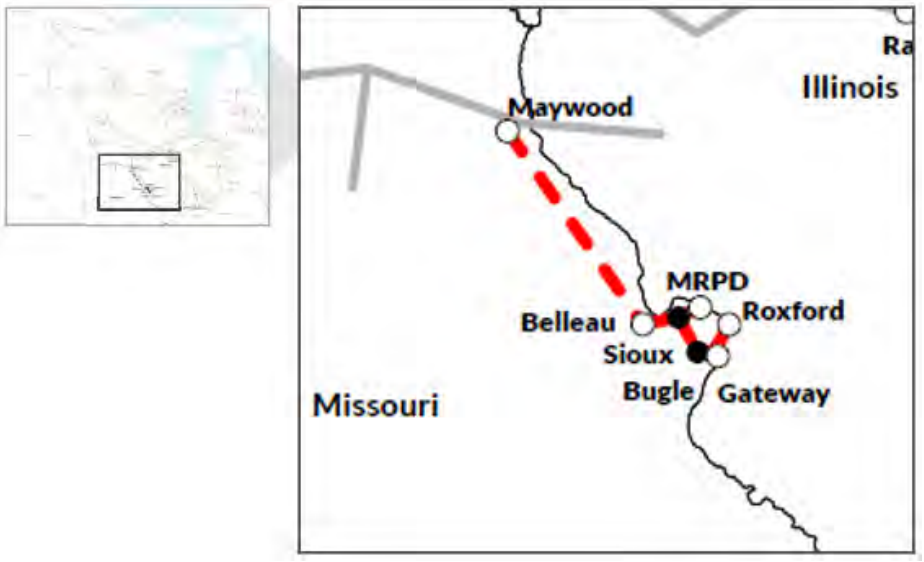


Figure 2.116: Missouri LRTP Tranche 2.1 projects

The 345 kV project in Missouri resolves numerous constraints in St. Louis Metro region and enables increased intraregional transfers across the Central Region. There are five limiting elements <200 kV that were not completely addressed with the addition of the portfolio, see table below. Worth noting, the loading of the elements are relatively the same with and without the portfolio and may be resolved in the annual MTEP reliability planning and generator interconnection processes. The geographically distant constraint, the [AMMO] Overton 345/161 kV transformer loading percent is greatly reduced with the addition of the portfolio.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[AECI] Essex – [AMMO] Richland 161 kV	124	124
2	[AMMO[Joachim 345/138 kV transformer	118	114
3	[AMMO] Overton 345/161 kV transformer	128	108
4	[AECI] Big Creek – [AMMO] Warrenton 161 kV	115	112
5	[AMMO] Ester –[AMMO] Rivermines 138 kV	110	109

Figure 2.117: Unresolved constraints in Missouri better suited for resolution in MTEP or queue processes

There were zero areas of LRZ 5 where new system constraints are being introduced. The top 20 facilities mitigated are provided in the table, the portfolio resolved all thermal violations on 200 kV and above facilities in Missouri and nearby Illinois area. The top 10 facilities resolved are geographically represented on the map.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[AMMO] Mason 345/138 kV Transformer	114	92
2	[AECI] McCredie-[AMMO] Montgomery 345 kV	108	65
3	[AMMO] Scarlett-[AMMO] Montgomery 345 kV	103	76
4	[AMMO] Belleau 345/138 kV Transformer	108	49
5	[AMMO] Enon-[AMMO] Montgomery 345 kV	105	71
6	[AMMO] Loy Martin-[AMMO] McBain 161 kV	124	70
7	[AMMO] Apache-[AMMO] California 161 kV	124	71
8	[AECI] Cyrene-[AMMO] Pike 161 kV	128	66
9	[AMMO] Franklin-[AECI] Clover Bottom-[AMMO] Tegeler - [AMMO] Bland 138 KV	110	73
10	[AMMO] Moberly-[KCPL] Salsbury 161 kV	101	99
11	[AMMO] Mason-[AMMO] Schuetz 138 kV	104	69
12	[AMMO] Dorsett-[AMMO] Schuetz 138 kV	105	67
13	[AMMO] Dorsett-[AMMO] Warson 138 KV	100	62
14	[AMMO] Loy Martin-[AMMO] Guthrie 161 KV	112	62
15	[AMMO] Belleau-[AMMO] Fort Zumwalt 138 kV	131	62
16	[AMMO] Fort Zumwalt-[AMMO] McClay 138 kV	121	53
17	[AMMO] Fort Zumwalt-[AMMO] Huster 138 kV	106	48
18	[AECI] Palmyra-[AMMO] Hannibal West 161 kV	105	61
19	[AMMO] Overton 1-[AMMO] Overton 2 161 kV bus tie	111	83
20	[AMMO] McBain-[AMMO] Overton 161 kV	127	97

Table 2.19: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

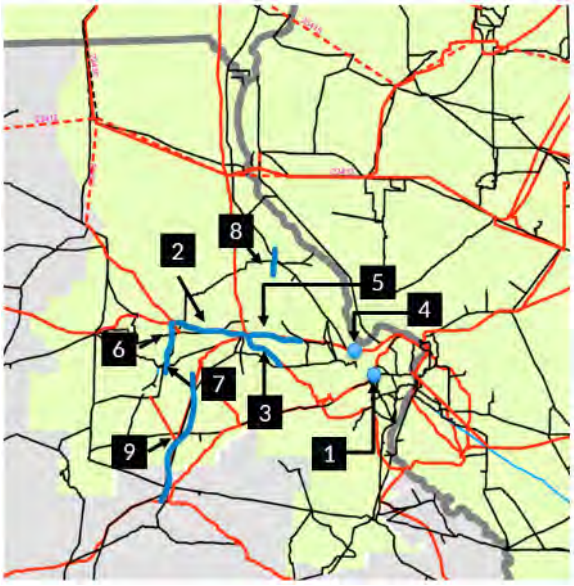


Figure 2.118: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

Project 37 is located within LRZ 5 and is responsible for the majority of the congestion relief seen in the LRZ. Project 37 reduces congestion in LRZ 5 by adding another path directly north of congested facilities and providing west to east relief. Table 2.20 and Figure 2.119 illustrate this further.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Project 37			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 539: [AMMO] 4FTZUM_TP 1 - [AMMO] 4HUSTER 3 138 kV 1	697,486	-	697,486
Event 355: [AMMO] 7ENON_TP - [AMMO] 7MONTGMRY 345 kV 1	41,533	12,601	28,932
Event 21: [AMIL] 4MORO - [AMIL] 4LACLEDE NTP 138 kV 1	224,528	196,378	28,150
Event 680: [AMMO] 4ESTHER TP2 - [AMMO] 4RIVMIN 2 138 kV 1	112,531	88,873	23,658
Event 420: [AECIZ] 5FLETCH - [AMMO] 5BR CREEK 161 kV 1	130,809	110,260	20,549
Event 1350: [AMMO] 4WITTNBRG - [AMIL] 4JENKINS 138 kV 1	26,138	12,925	13,213
Event 539: [AMMO] 7BELLEAU 345 kV - [AMMO] 4BELLEAU 1 138 kV 1	10,665	-	10,665
Event 1152: [AMIL] 4CAHOK 1 - [AMIL] 4RIDGE 2 138 kV 1	45,847	37,078	8,769
Event 582: [AMMO] 7MONTGMRY - [AMMO] 7SPENCER 345 kV 1	8,595	-	8,595
Event 324: [AECIZ] 5ESSEX - [AMMO] 5RICHLAND_TP 161 kV 1	16,661	14,253	2,408

Table 2.20: Top Relieved Economic Flowgates – Project 37

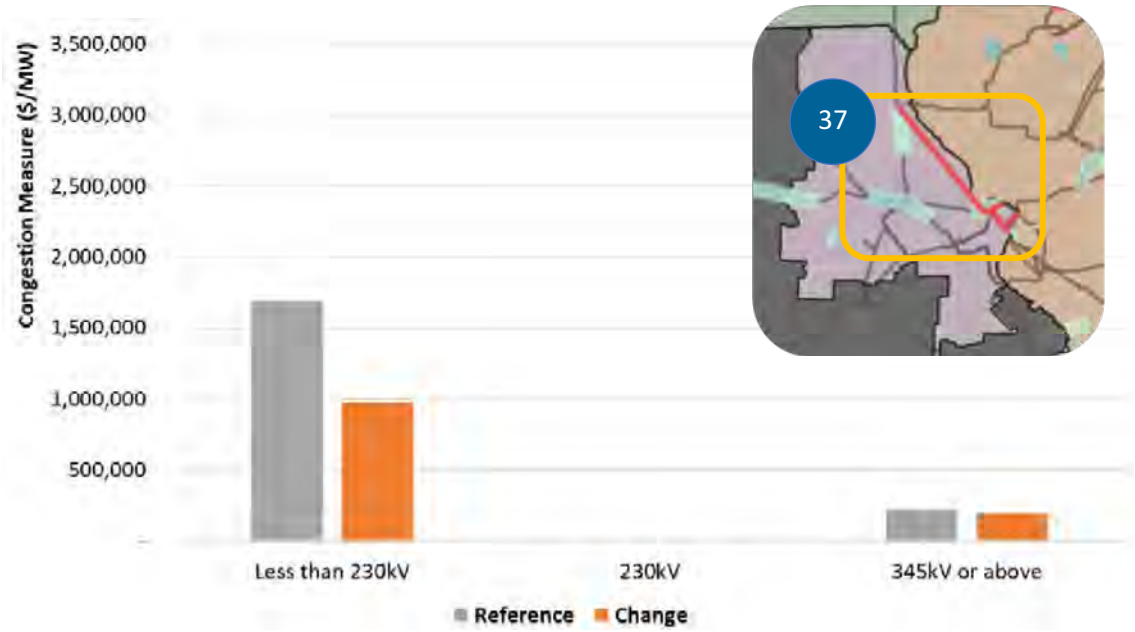


Figure 2.119: Congestion Measure – Project 37

LRZ 6 – Indiana

The Tranche 2.1 portfolio resolves most of the thermal violations in LRZ 6 for 200 kV and above facilities. The Tranche 2.1 portfolio improves transfer capability in Central/Southern Indiana by enabling more power to reach large load centers reliably.

The Tranche 2.1 portfolio reduces congestion evenly across LRZ 6, with all companies seeing congestion relief as shown in Figure 2.120. The portfolio also demonstrates relief throughout LRZ 6 footprint at multiple kV levels. Total congestion in LRZ 6 is reduced by 38.2% (1027 k$/MW). Load serving costs decrease year-round and throughout LRZ 6, as shown in Figure 2.121, by an average of $3.61 / MWh. Increased exports through transmission boost energy transfers while reducing costs for purchasing companies. With increased access to low-cost resources from the larger region, the Tranche 2.1 portfolio sees curtailments in LRZ 6 increase by 0.9M MWh. Relief of transmission constraints enables 16.6 GW of generation.

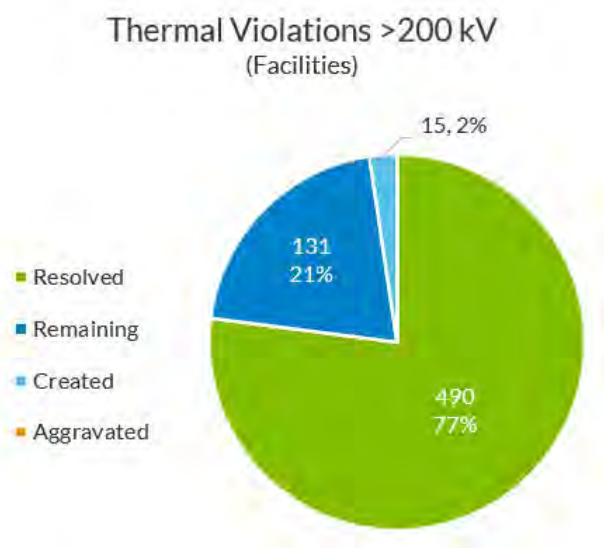


Figure 2.120: Thermal constraint resolution for LRZ6

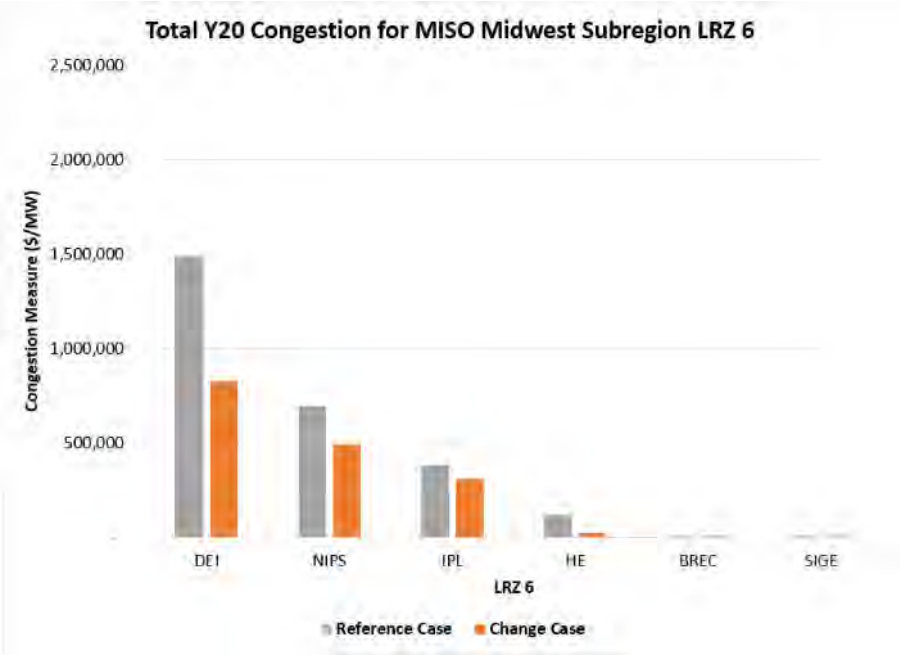


Figure 2.121: Congestion Measure – LRZ 6

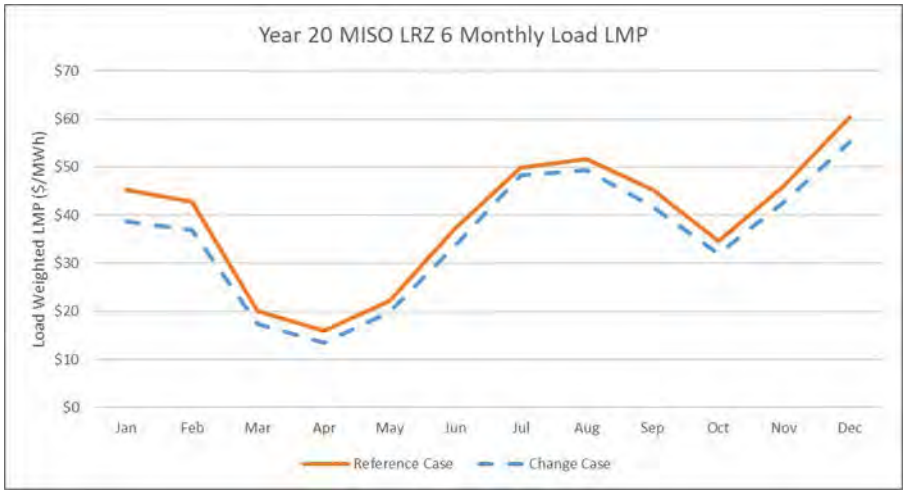


Figure 2.122: Comparison: Monthly Load LMP – LRZ 6

Southwest Indiana – Kentucky (Project 35) and Southeast Indiana (Project 36)

Southern IN/KY 345 kV project resolves constraints in the region and promotes West – East transfers across the central region. Southeast IN upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the IN load centers in Central IN and Southeastern IN.

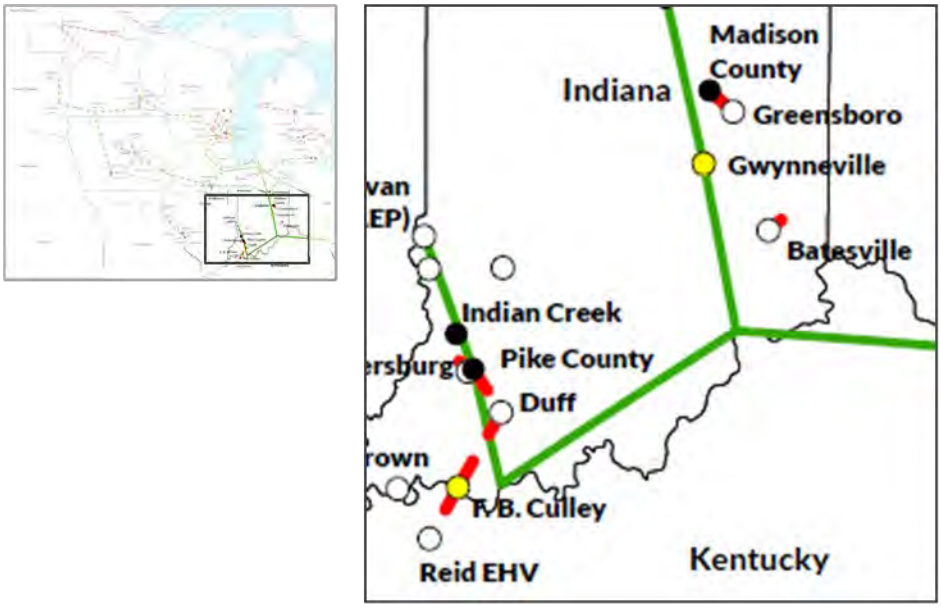


Figure 2.123: Southwest Indiana – Kentucky and Southeast Indiana LRTP Tranche 2.1 projects

There are two main areas of LRZ6 where system constraints were not completely addressed and these areas fall both in Central Indiana, as noted below in tables. The [DEI] Qualitech-[DEI] Whitestown-[IPL] Guion 345 kV and the [DEI] Kokomo-[DEI] Tipton-[DEI]-Carmel 230 kV transmission corridors are both overloaded with the portfolio, though the loading percents have been greatly reduced. The [DEI] Noblesville-[DEI] Madison County-[AEP] Fall Creek 345 kV transmission corridors are showing overloads

with the addition of the portfolio, though the loading percentages have been greatly reduced. Other facilities experienced aggravated loadings and all of the facilities referred to here are attributed to local drivers and better resolved in the annual MTEP reliability planning and the generator interconnection processes.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[DEI] Qualitech –[DEI] Whitestown –[IPL]Guion 345 kV	168	140
2	[DEI] Kokomo –[DEI] Tipton –[DEI] Carmel 230 kV	143	118
3	[DEI] Noblesville - [DEI] Madison County [AEP] Fall Creek 345 kV	121	107

Table 2.21: Loadings significantly relieved, full resolution better suited for MTEP and queue processes in LRZ6

The top 20 lines with the most reduction in the loadings are shown in the table below. The third column shows the highest loading for these elements in the base models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The Fall Creek – Noblesville 345 kV line listed below as 15 is reconfigured to the Fall Creek to Madison County to Noblesville 345 kV line to accommodate the new 345 kV circuit from Greensboro to Madison County in the Tranche 2.1 portfolio. The locations of the top 10 lines are shown on the map below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[DEI] Noblesville – [DEI] Durbin 230 kV	105	81
2	[DEI] Hortonville – [DEI] Whitestown 230 kV	106	88
3	[DEI] Nucor – [DEI} Whitestown 230 kV	111	89
4	[DEI]Staunton – [DEI] Wabash River 230	117	79
5	[DEI]Wheatland – [DEI]Edwardsport 345 kV	126	Reconfig
6	[DEI] Gibson– [LGEE] Wheatland 345 kV	107	11
7	[DEI] Speed – [LGEE] Trimble County 345 kV	107	94
8	[DEI] Batesville – [DEI] Hubble – [DEI] Weisburg – [DEI] Wilmington – [HE] Hidden Valley – [DEI] Greendale – [DEO&K] Miami Fort 138 kV	145	55
9	[SIGE] Newtonville – [SIGE] Grandview – [SIGE] Rockville Tap 138 kV	118	69
10	[BREC] Reid – [BREC] Hopkins County – [BREC] Caldwell – [BREC] Barkley HP 161kV – [BREC] Henderson County 161/138 kV transformer	113	79
11	[HE] Decatur – [DEI] Greensburg 138 kV	132	47
12	[DEI] Plainfield – [WVPA] Airport West 138 kV	107	81
13	[DEI] Wabash River 230/138 kV transformer 1B	110	56
14	[DEI] Lapel – [DEI] Noblesville 230	101	82
15	[AEP] Fall Creek – [DEI] Noblesville 345 kV	121	Reconfig
16	[IPL] Guion – [IPL] Pike 138 kV	108	96
17	[IPL] Guion – [IPL] Westlane 138 kV	102	94
18	[IPL] Guion – [IPL] Mill Street 138 kV	108	90
19	[IPL] Guion – [IPL] Tremont 138 kV	103	90
20	[DEI] Vincennces – [DEI] Lawrenceville 138 kV	105	68

Table 2.22: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

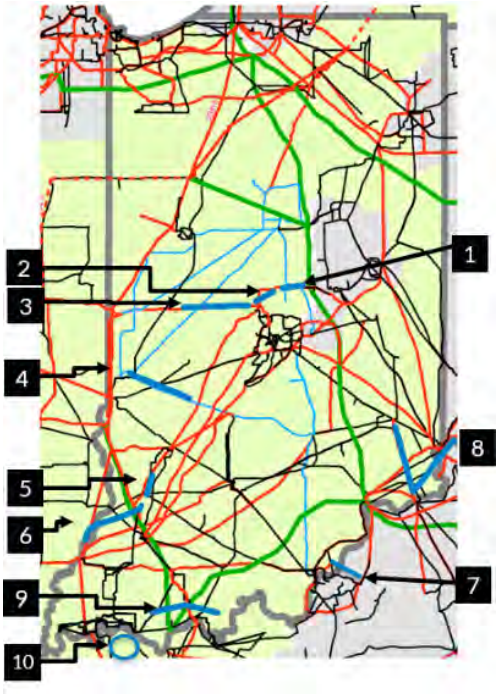


Figure 2.124: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

Projects 35 and 36 provide relief for many lower kV constraints in the mid-southern area of the LRZ, shown below in Table 2.9 and Figure 2.123. They enable more generation to reach the load centers in Central and Southeastern Indiana.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 35 & 36			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 154: [DUK-IN] 08WILM J - [DUK-IN] 08WEISBG 138 kV 1	72,018	-	72,018
Event 246: [DUK-IN] 08WILM J - [DUK-IN] 08WEISBG 138 kV 1	70,780	-	70,780
Event 153: [HE] 07DCTRSS - [DUK-IN] 08GRNSBR 138 kV 1	70,391	-	70,391
Event 36: [HE] 07DCTRSS - [DUK-IN] 08GRNSBR 138 kV 1	61,494	-	61,494
Event 2: [DUK-IN] 08KOK HP - [DUK-IN] 08TIPTN 230 kV 1	58,806	-	58,806
Event 572: [DUK-IN] 08KOK HP - [DUK-IN] 08TIPTN 230 kV 1	55,899	3,382	52,517
Event 167: [IPL] 16GUION - [IPL] 16WSTLAN 138 kV 40	238,760	186,961	51,799
Event 243: [HE] 07HUBBL8 - [DUK-IN] 08BATESV 138 kV 1	39,313	-	39,313
Event 2: [DUK-IN] 08WHITST - [IPL] 16GUION 345 kV 1	142,080	112,538	29,542
Event 1025: [DUK-IN] 08LAFAYE 230kV - [DUK-IN] 99494 YBUS504 100 kV 1	50,262	28,268	21,995

Table 2.23: Top Relieved Flowgates – Projects 35 & 36

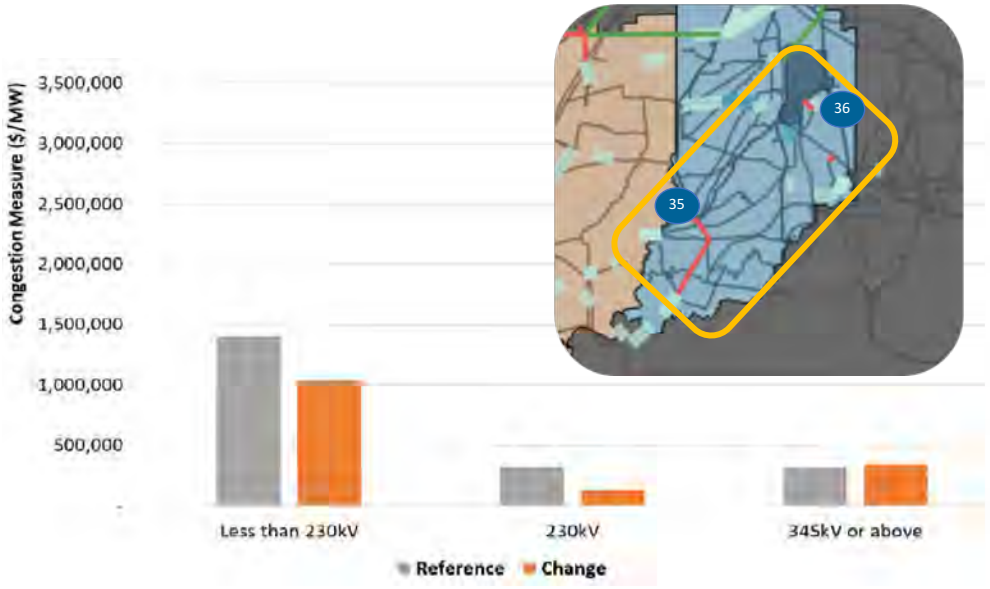


Figure 2.125: Congestion Measure – Project 35 & 36

East Region – Reliability and Economic Results

- Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability
- Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the Eastern load centers
- MI to Northeast IN project supplement the existing connections into Michigan and provide the transfer capability in and out of MI

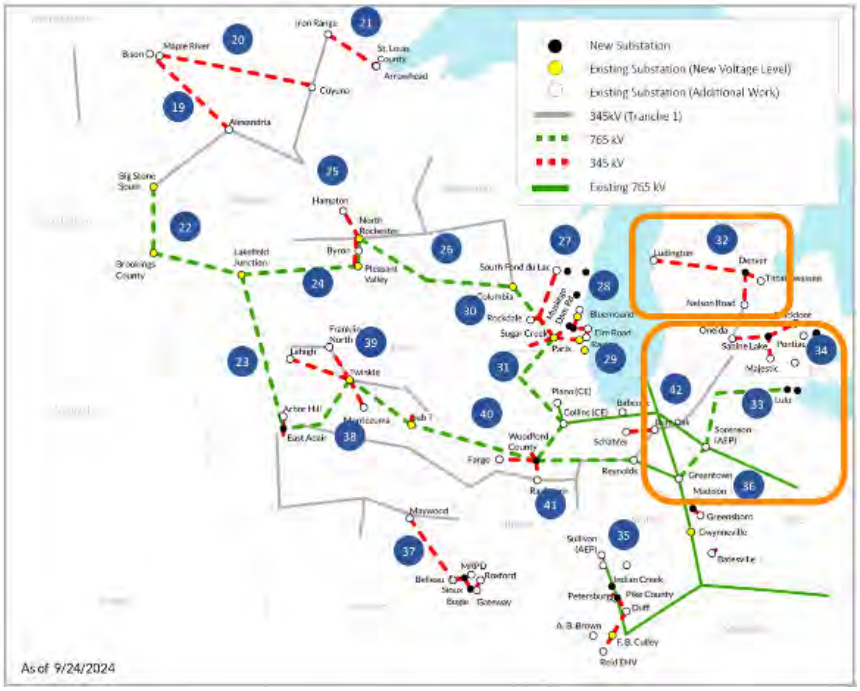


Figure 2.126: East Region Project Groups

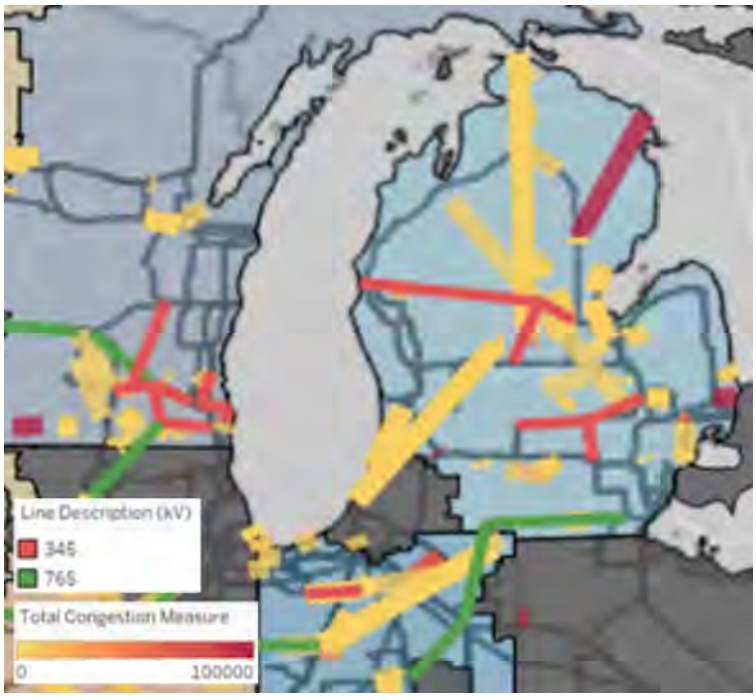


Figure 2.127: Change Case Economic Congestion - East

LRZ 7 – Michigan

For the <200 kV system, 31% of the violations have been resolved. For the >200 kV system, stronger East to West ties are established in the MI footprint. These ties shift flow patterns in the region by allowing access

to remote resources and provide high utilization of new Tranche 2 lines. For the >200 kV system, a majority of the remaining and created violations occur in the twilight, low winter renewable, and lower-upper transfers, where the system is stressed. The remaining reliability issues are specific to local generation sited or load which has better resolution through annual MTEP reliability planning and the generator interconnection processes.

Tranche 2.1 portfolio reduces congestion in LRZ 7 by using regional facilities to relieve local congested areas. Congestion is reduced in LRZ7 by 31.7% (950 k$/MW), and most of the relief is on local constraints near 345 kV additions. Few constraints see increased economic congestion. Both companies see notable congestion relief, as shown in Figure 2.128. Load serving costs decrease year-round and throughout LRZ7 by an average of $3.70 / MWh, generally lowering LMPs in higher cost areas of the state. This is detailed in Figure 2.129. Curtailment reductions are seen in the central part of the LRZ near new transmission, and relief of transmission constraints enables 11.2 GW of generation in LRZ 7. Tranche 2.1 portfolio maintained the relatively low curtailments in LRZ 7, only increasing them by 1.1M MWh. Curtailments, shown in Figure 2.130, improved near the eastern terminus of Project 32. Relief of transmission constraints enables 11.2 GW of generation.

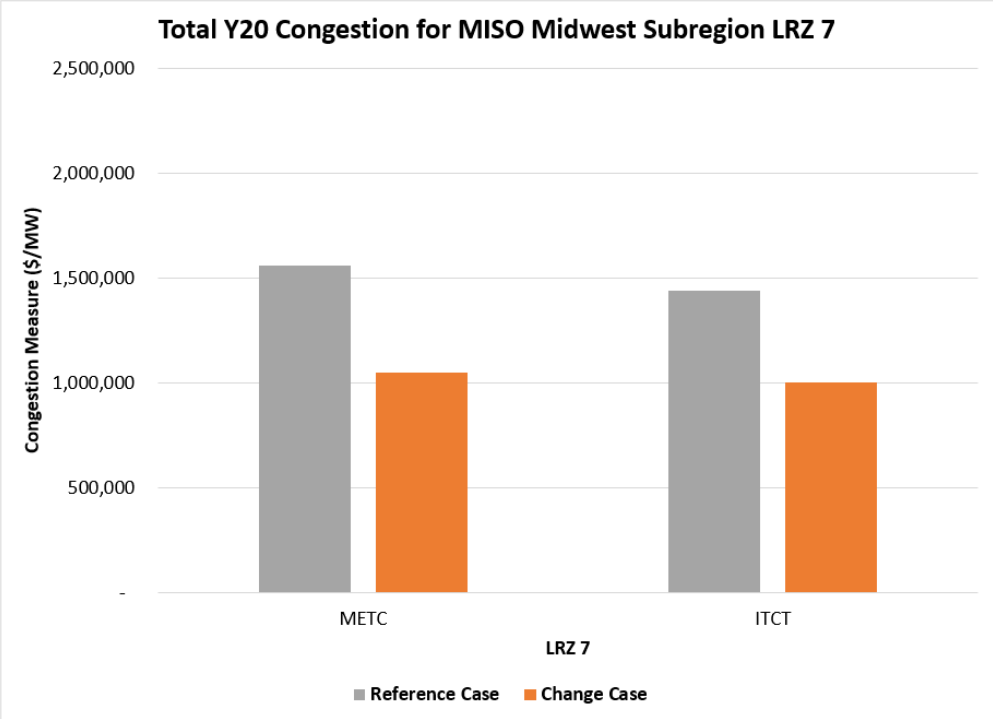


Figure 2.128: Congestion Measure – Project 37

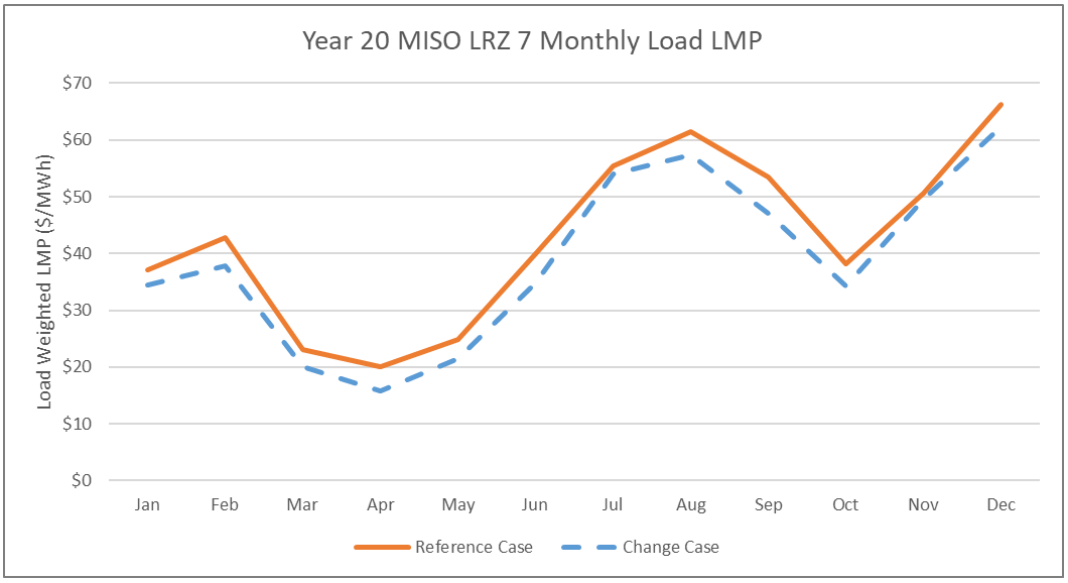


Figure 2.129: Comparison: Load LMP – Project 37

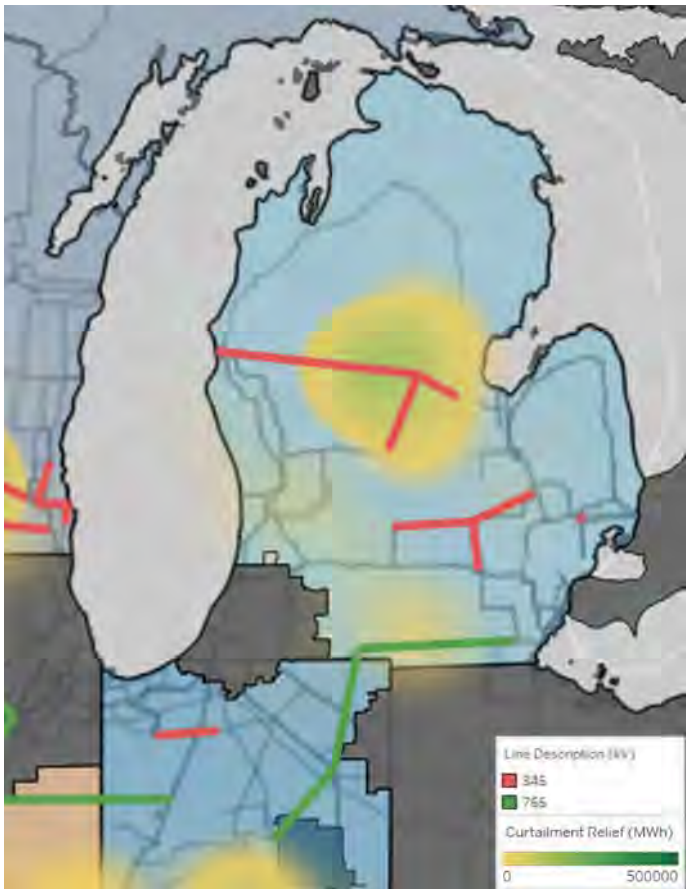


Figure 2.130: Change Case Curtailment Relief – LRZ 7

Ludington - Denver - Tittabawassee & Nelson Road 345 kV (Project 32)



Figure 2.131: Central Michigan LRTP Tranche 2.1 projects

Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability. Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the eastern load centers. The bulk of the identified constraints in Central MI were on the 138 kV line, as this is the predominant voltage in the area. Tranche 2.1 portfolio resolves 37% of thermal violations on 200 kV and below facilities in Central Michigan.

Another key benefit of Central MI projects is aiding the bi-directional nature within the MI system. Ludington Pumped Storage Plant functions as either a significant source of generation, or a significant load to the MI system. This is exhibited by both West to East and East to West flows on the added facilities, respectively. The table shows the most reduction in loadings, while the figure shows the first eight elements.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[METC] Bullock-[METC] Edenville Junction 138 kV	175	34
2	[METC] Bullock-[METC] Salt River Junction 138 kV	193	27
3	[METC] Regal -[METC] Luce 138 kV	186	53
4	[METC] Tittabawassee -[METC] Redstone 138 kV	135	58
5	[METC] Summerton-[METC] Camelot Lake 138 kV	159	9
6	[METC] Camelot Lake Jct -[METC] Salt River 138 kV	160	10
7	[METC] Lewiston-[METC] Plywood Jct 138 kV	115	91
8	[METC] Plywood Jct-[METC] Bagley 138 kV	115	90
9	[METC] Chase -[METC] Mecosta 138 kV	108	93
10	[METC] Hillman -[METC] Airport 138 kV	112	87
11	[METC] Bluegrass Jct -[METC] Summerton 138 kV	131	22
12	[METC] Edenville Junction 138 kV-[METC] Salt River 138 kV	111	13

Table 2.24: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

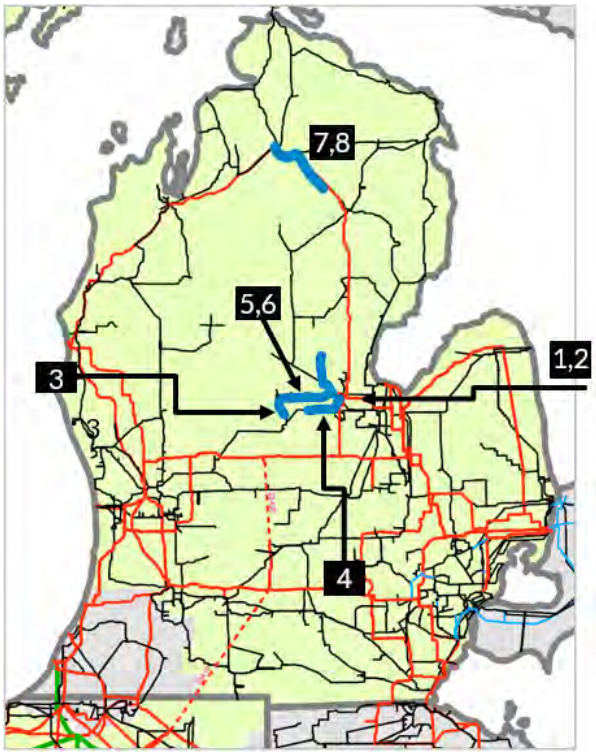


Figure 2.132: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

Project 32 provides congestion relief to lower kV local constraints located in the central part of the LRZ near the project. It does so by pulling flows off of the local system and distributing them more evenly towards surrounding load centers. Table 2.24 and Figure 2.134 illustrate this.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Project 32			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 627: [CONS] 18BULLOCKW - [CONS] 18SALTRIV 138 kV 1	107,294	-	107,294
Figure	65,165	247	64,918
Base Case: [CONS] 18DEJAJ - [CONS] 18VESTABURG 138 kV 1	55,520	61	55,460
Event 826: [CONS] 18ALMA - [CONS] 18REGAL 138 kV 2	52,867	163	52,704
Event 227: [CONS] 18BULLOCKB - [CONS] 18EDNVLJ 138 kV 1	39,857	-	39,857
Event 9: [CONS] 18HLLMNJ - [CONS] 18AIRPORTW 138 kV 1	28,106	7,124	20,982
Event 529: [CONS] 18CORWTJ - [CONS] 18RONDO 138 kV 1	56,298	36,235	20,063
Event 163: [CONS] 18GALAGR - [CONS] 18GRNWDJ 138 kV 1	15,857	0	15,857
Event 627: [CONS] 18CAMLTJ - [CONS] 18SALTRIV 138 kV 1	13,502	-	13,502
Event 150: [CONS] 18CAMLTJ - [CONS] 18SALTRIV 138 kV 1	11,583	0	11,583

Table 2.25: Top Relieved Economic Flowgates – Projects 32

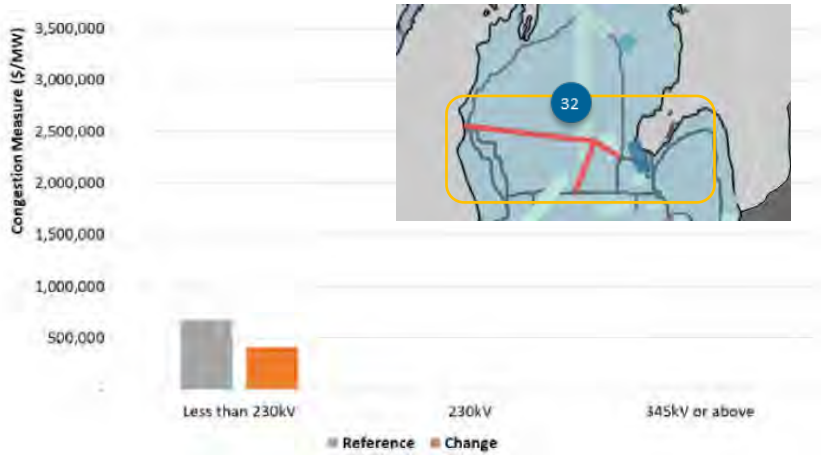


Figure 2.133: Congestion Measure – Project 32

Greentown - Sorenson - Lulu 765 kV (Project 33), Oneida - Sabine Lake - Blackfoot & Majestic 345 kV (Project 34), and Burr Oak – Schafer 345 kV (Project 42)

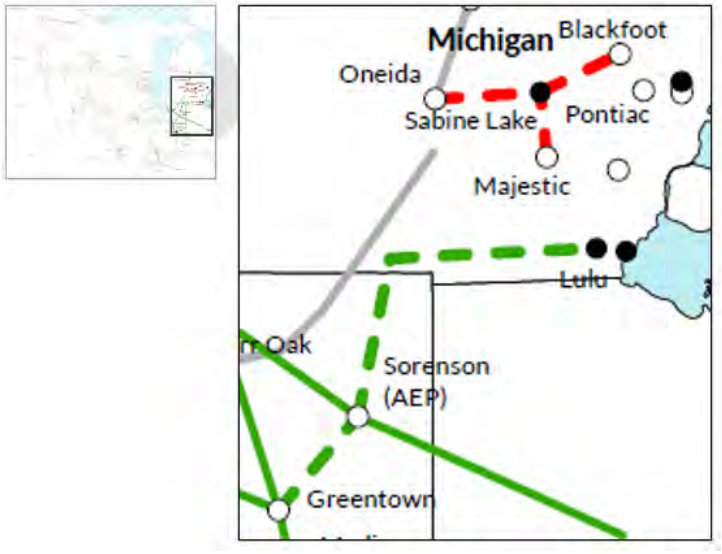


Figure 2.134: Southern Michigan and Northeastern Indiana LRTP Tranche 2.1 projects

The MI to Northeast IN project supplements the existing connections into Michigan and provides the transfer capability in and out of MI. Additionally, the re-configuration near existing Babcock and Burr Oak substations in Northwestern IN strengthen a load pocket that will increasingly rely on support from the rest of the MISO system as local generation retires.

In the average and light load core models, where batteries are charging and solar output is modest to non-existent, MI is importing approximately 5.7 GW. During peak summer and winter cases, MI is exporting approximately 3 GW and 1.6 GW, respectively. Drivers for these large swings can be attributed to a heavy concentration of solar and battery resources in the MI footprint in F2A, coupled with Ludington Pumped Storage Hydro.

The Sorenson to Lulu 765 kV line maintains system reliability as Michigan experiences increasingly large swings in imports and exports. From the constraints resolved map, thermal violations are resolved on the Argenta lines (Western MI) as MWs transfer into or out of the Detroit area (load center) or thumb of MI (generation center) via the Sorenson to Lulu 765 kV line. Additionally, the Oneida - Sabine Lake - Blackfoot & Majestic 345 kV strengthens the pathways into the Detroit area by interconnecting with Tranche 1 facilities. Ultimately these new 345 and 765 kV lines increase the ability of the MI system to handle large generation swings throughout the year. The table shows the most reduction in loadings, while the figure shows the first nine elements.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[ITCT] Jewell -[ITCT] Bismarck 345 kV	115	54
2	[ATSI] Lallendorf-[ITCT] Monroe 345 kV	117	Reconfigured
3	[AEP] Lemoyne–[ITCT] Maple 345 kV	122	Reconfigured
4	[METC] Oneida 345/138 kV transformer	111	82
5	[METC] Delhi–[METC] Green 138 kV	149	83
6	[METC] College–[METC] Green 138 kV	139	76
7	[METC] Argenta–[METC] Palisades 345 kV 1	108	93
8	[METC] Argenta–[METC] Palisades 345 kV 2	115	99
9	[METC] Argenta –[METC] Meyer 345 kV	102	87
10	[METC] Hagadorn Junction–[METC] Tihart 138 kV	129	68
11	[METC] Hagadorn Junction–[METC] College 138 kV	106	57

Table 2.26: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Michigan and Northeastern Indiana

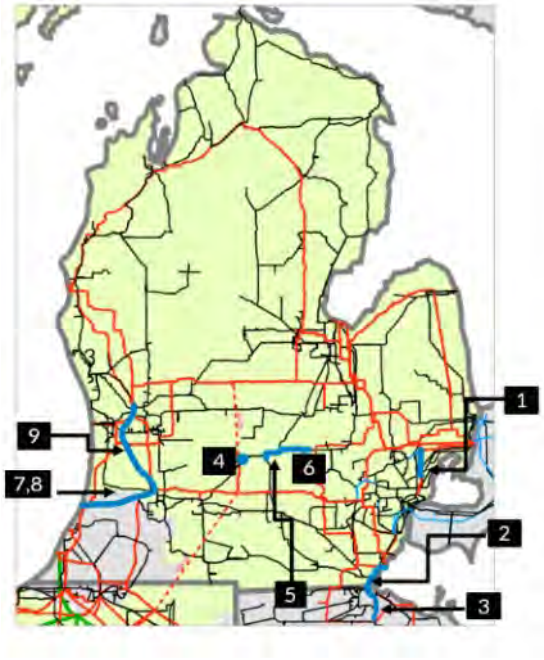


Figure 2.135: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Michigan

Projects 33, 34, and 42 provide relief to lower kV local constraints in the southern and southeastern portions of the LRZ, illustrated in Figure 2.135. Table 2.27 shows the relieved flowgates ranked by congestion measure relief for projects 33, 34, and 42.

Y20 Top Relieved Flowgates - Projects 33, 34 & 42			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 126: [DECO] 19CANIF7 - [DECO] 19HAMTRAMCK6 120 kV 1	281,619	166,593	115,026
Event 1156: [DECO] 19BUNCE1 - [DECO] 19FITZ 120 kV 1	131,271	25,320	105,951
Event 1018: [DECO] 19LEE1 - [DECO] 19LHPMPT 120 kV 1	102,215	22,023	80,192
Event 136: [DECO] 19CANIF7 - [DECO] 19HAMTRAMCK6 120 kV 1	315,538	244,547	70,991
Event 1004: [CONS] 18HALSEY - [CONS] GRAND BOC 2 138 kV 1	89,505	24,908	64,596
Event 1124: [CONS] DEAN RD - [CONS] OAKLAND 138 kV 1	41,314	11,652	29,662
Base Case: [NIPS] 17STJOHN - [COMED] CRETE EC ;BP 345 kV 1	30,400	800	29,600
Base Case: [CONS] PLYMOUTH 1 138kV - [CONS] YBUS536 100 kV 12	411,950	382,553	29,397
Event 1114: [DECO] 19CLRDT1 - [DECO] 19PONTC2 120 kV 1	107,992	79,373	28,619
Event 55: [CONS] 18LEONI - [CONS] 18WSHTNJ 138 kV 1	36,842	11,248	25,594

Table 2.27: Top Relieved Economic Flowgates – Projects 33, 34, & 42

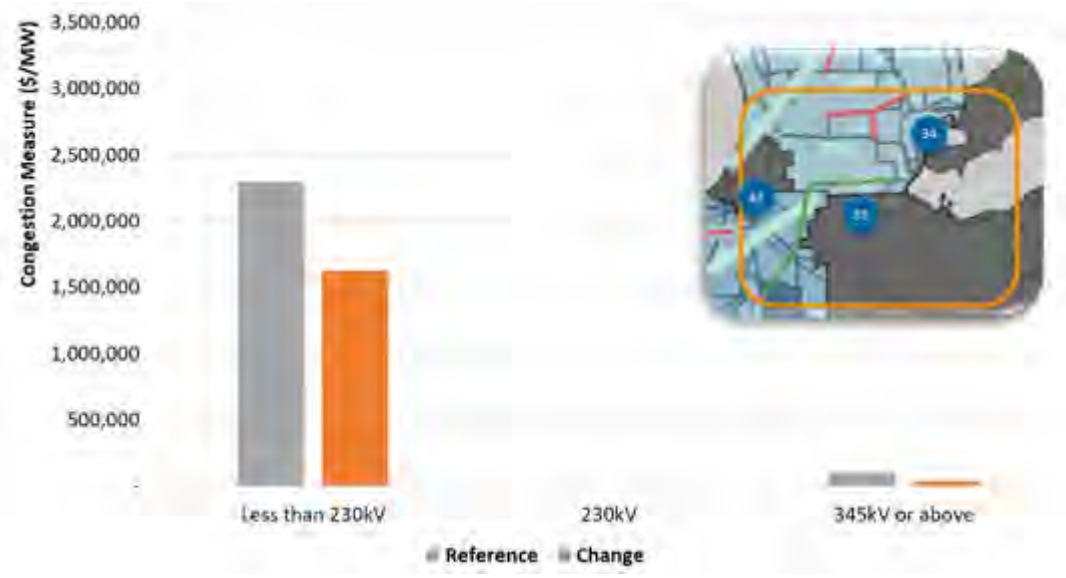


Figure 2.136: Congestion Measure – Project 33, 34 & 36

Business Case Analysis

In accordance with the guiding principles of the MISO transmission planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility criteria are established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

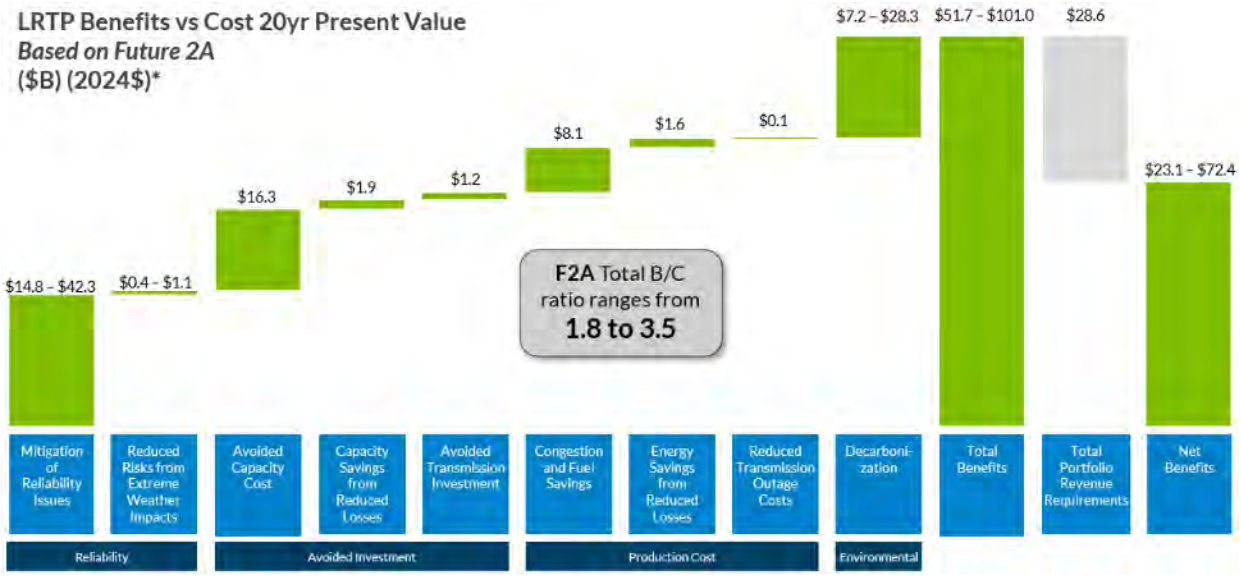


Figure 2.137: Financially Quantifiable Benefits of Tranche 2.1 Portfolio (values as of 11/1/2024).

Guided by the financially quantifiable benefits defined in the tariff for MVP projects, the following benefit metrics were evaluated to determine the amount of value delivered by the Tranche 2.1 Portfolio:

Reliability Benefits	1. Mitigation of reliability issues	Value of alleviating reliability issues which, if unresolved, introduce a risk of unserved load
	2. Reduced risks from extreme weather events	Increases grid resilience and decreases the probability of major service interruptions
Avoided Investment Benefits	3. Avoided capacity costs	Avoids capital costs for local resource builds versus regional expansions defined in Futures
	4. Capacity Savings from Reduced Losses	Value of reducing transmission losses during peak capacity periods
	5. Avoided transmission investments	Avoids the need for facility replacement due to age and condition
Production Cost Benefits	6. Congestion and fuel savings	Enhances market efficiency and provides access to low-cost generation
	7. Energy Savings from Reduced Losses	Lower production costs to serve load with transmission facilities that reduce system losses
	8. Reduced transmission outage costs	Reduced transmission congestion during forced and planned transmission outages
Environmental Benefits	9. Decarbonization	Enables the economical dispatch of renewable resources to help reduce the carbon footprint

Table 2.28: Nine Benefit Metrics used for Tranche 2.1.

Each benefit metric represents a distinct piece of the overall value resulting from the transmission investments. The nine benefit metrics can be grouped into four categories of benefits – reliability (1 and 2), avoided investment (3, 4 and 5), production costs (6, 7 and 8), and environmental (9). The methodologies were developed to define the calculations used to assess the impact of LRTP Tranche 2.1 projects on specific financially quantifiable measures that reflect the value of the investment and are summarized in this report. The details of the methodologies are more fully discussed within the LRTP Tranche 2 Business Case Metrics Methodology Whitepaper.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. Benefits were calculated over a 20-year period as required for MVPs in accordance with the MISO Tariff, starting from the assumed in-service year of 2032, and over a 40-year period to demonstrate the additional value provided by the portfolio over the many decades beyond 20-years the portfolio is expected to be in-service. All benefit values are expressed in 2024 dollars. A discount rate of 7.1 percent is used to calculate the minimum value used to assess the benefit-to-cost ratio and is based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. Benefits are also assessed using a rate of three percent to show how assets perform with a social discount rate that reflects the return a ratepayer would typically receive on a risk-adjusted investment.

While the LRTP Tranche 2.1 Portfolio study has focused on Future 2A, the benefits analysis has also been performed using Future 1A to provide a lower-bookend representation of the value the portfolio provides.

Future 2A Benefit Metric Analysis

Mitigation of Reliability Issues

High-Level Methodology Overview

Traditionally, the NERC TPL standard has been used to ensure the transmission system is planned to be reliable. The NERC TPL standards articulate a minimum level of reliability with which the transmission system must support.

With regard to long-range transmission planning, the objective is to ensure the regional system is reliable and cost effective in the long-term given the many changes that are expected to the resource fleet and load characteristics. In that respect, long-range transmission planning is not TPL compliance-focused, but instead value-focused. LRTP seeks to determine the benefits of reliability improvements associated with long-term projects.

The reliability benefit metric captures where LRTP resolves reliability issues, as defined by instances where the post contingent load under steady state conditions would exceed applicable facility limits after redispatch. The benefit of remediating reliability issues is determined by quantifying the avoided risk of load shedding that would be needed to return the facility within applicable limits and monetizing the value. This load shedding is used as a measure of reliability risk rather than an operating action taken to resolve issues.

Analysis of benefits is performed in a two-step process which applies preventive generation re-dispatch in the first step to mitigate initial overloads followed by a corrective load re-dispatch process to calculate the minimum load shedding to address the contingency violations. This analysis uses the TARA software application to perform an optimal security constrained reliability dispatch for NERC Category P1, P2, and P7 contingencies associated with the LRTP resolved issues.

Thermal overloads identified in each of the core (seasonal) study scenarios for the 2032 and 2042 study years that are relieved by the addition of the LRTP Tranche 2 portfolio, and their associated contingencies are compiled and monitored in the first past generation re-dispatch step. Since seasonal study models are snapshots that reflect a wide range of load and generation dispatch conditions, two dispatch scenarios are created for each of the core study scenarios. The first scenario represents hours with excess renewable availability where renewables are allowed to dispatch in the upward direction. The second scenario represents hours with less renewable availability than modeled where renewables are limited in dispatch to the downward direction.

The unresolved overloads from the generation redispatch step are compiled and monitored in the second pass load redispatch step to calculate load shedding needed to mitigate the remaining thermal overloading. The reduction in load at each bus is calculated and the maximum value for each bus for all contingencies is summed to determine quantity of load shedding needed in each dispatch scenario. The value of this load shedding amount is multiplied by the hours represented by the dispatch scenario and summed to quantify the total risk of unserved energy (in MWh). This value is then multiplied by the Value of Lost Load (VOLL) to monetize the benefit.

$$\text{Benefit} = \sum_1^n LoadShedMW * VOLL$$

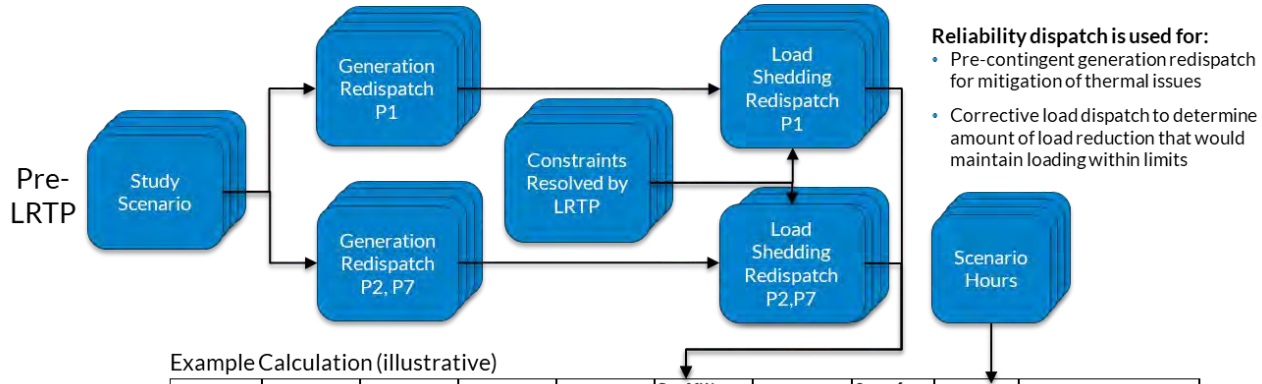
Where

n = dispatch scenario/season

LoadShedMW = amount of load redispatch for each study scenario

VOLL = Value of Lost Load ($3,500/MWh - $10,000/MWh)

Benefits are accrued on a one-time basis for each of the study years (2032 and 2042) and issues identified in the earlier 2032 study year are excluded from consideration in the later 2042 study year. Any reliability issues that are identified are assumed to be mitigated and pose no further risk in the later years to provide a more conservative estimate.



Example Calculation (illustrative)

Model	Redispatch Scenario	Monitored	Contingency	Pre-overload %	Pre-MW Relief Required	Buses	Sum of Max Load Shed MW	Scenario Hours	MWh Benefit
2032sum	up/down	St A- St B	P1_Ctg1	115%	16MW	bus-a bus-b	124	48	5,952
2032avg	up/down	St C - St D	P1_Ctg2	124%	32MW	bus-c bus-d bus-e	46	420	19,320
2032avg	down-only	St E - St F	P1_Ctg3	107%	20MW	bus-f bus-g bus-h bus-i	295	1362	401,790
2032avg	down-only	St G - St H	P2_Ctg4	109%	18MW				
							Load Shedding MWh		427,062

Figure 2.138: Process for Identifying Load Shedding Risk

Results

LRTP Tranche 2.1 projects provide value by proactively addressing numerous thermal overloads that reduces risk of unserved load as indicated in table below and yields $14.8B benefits over a 20- to 40-year period.

Total Unserved Energy Risk by Season (GWh)				
Year	Summer	Winter	Average	Light Load
2032	449	58	2971	278
2042	149	80	400	115

Table 2.29: Avoided by Mitigation of Reliability Issues Benefits Summary of Avoided Unserved Energy

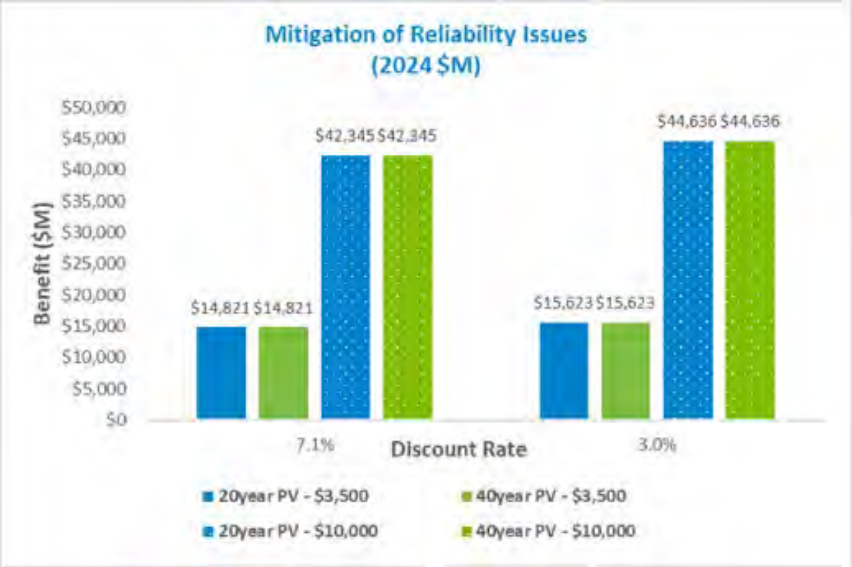


Figure 2.139: Mitigation of Reliability Issues Benefit Value

Reduced Risks from Extreme Weather Impacts

High-Level Methodology Overview

Reduced risks from extreme weather impacts reflects the value of reducing the risk of unserved energy during periods of expected supply deficiency attributed to extreme weather conditions. The increased penetration of variable resources that are reflected in the Futures scenarios, in combination with correlated outages of thermal resources and higher than expected load levels, will increase the risk of supply disruptions due to extreme weather and resulting in more unserved energy. Limited transmission capacity restricts access to resources that are needed to cover capacity shortfalls that can result in greater unserved energy. The addition of the Tranche 2.1 portfolio increases transfer capability to enhance capacity deliverability that reduces the amount of unserved energy.

The analysis uses PLEXOS software to perform probabilistic Loss of Load Expectation (LOLE) simulations using a simplified zonal transmission constraint model to assess the amount of expected unserved energy (EUE) observed in the worst intervals with and without the LRTP Tranche 2.1 portfolio. Hourly simulations are run using 14 weather years of load and renewable generation profiles with 150 samples to reflect the probabilities of forced outages including temperature-dependent correlated outages. Planned maintenance is also accounted for using maintenance outage rates and maintenance frequency. This analysis examines the Conditional Value at Risk (CVaR) to focus on the tails of the risk distribution (i.e. intervals with the highest EUE) which captures the benefits of addressing more extreme risks in a future with high levels of uncertainty and variability in the generation resources. The expected unserved energy metric is used to capture both the duration and magnitude of the loss of load events as a measure of the benefit. A threshold for CVaR is established from the event duration and magnitude and applied to the dataset to select the subset of events in the tail of the risk distribution that are used in the analysis and reflect the top percentage of EUE hours. The benefit metric applies a CVaR(80) target that is used to capture the top 20% of the worst events with greater than 2000 MWh unserved and 4 hour duration.

The reduced risk from extreme weather impacts measures the change in the expected unserved energy (EUE) during the most severe events and uses a VOLL equal to 3,500 $/MWh to monetize the lower end of this benefit and 10,000 $/MWh on the upper end. The economic value, which is applied from year 10, when LRTP transmission is enabled in the planning horizon and accrued every 5 years in accordance with CVaR(80) target,[3] is calculated by the following equation:

$$\text{Economic Value} = \left(\sum_{n=1}^{H} EUE\right) * VOLL$$

Where

EUE is Expected Unserved Energy (MW) in hour n

H is total hourly intervals

VOLL is the Value of Lost Load ($3,500 - $10,000MW/hr)

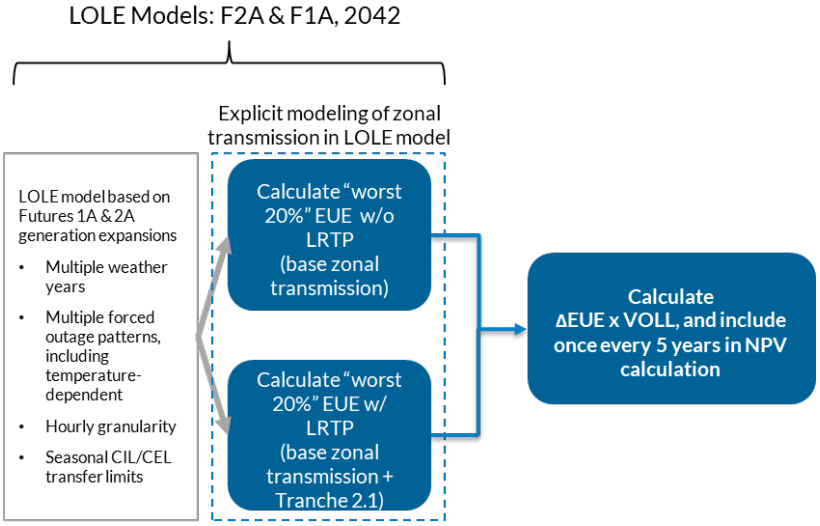


Figure 2.140: Reduced risk from extreme weather Calculation Process

Results

Analysis of the Reduced Risk from Extreme Weather Events benefit indicates that the increased transfer capability provided by the LRTP Tranche 2.1 portfolio improves system performance during extreme weather events. The portfolio provides reduction in Expected Unserved Energy of 37.9 GWh in the top 20% of event hours with the highest Expected Unserved Energy. The Tranche 2.1 portfolio delivers benefits of $394M - $557M over a 20- to 40-year period.

[3] For a CVaR(80), the benefit is applied to year 0, 5, 10, 15, 20 in the 20-yr NPV calculation.

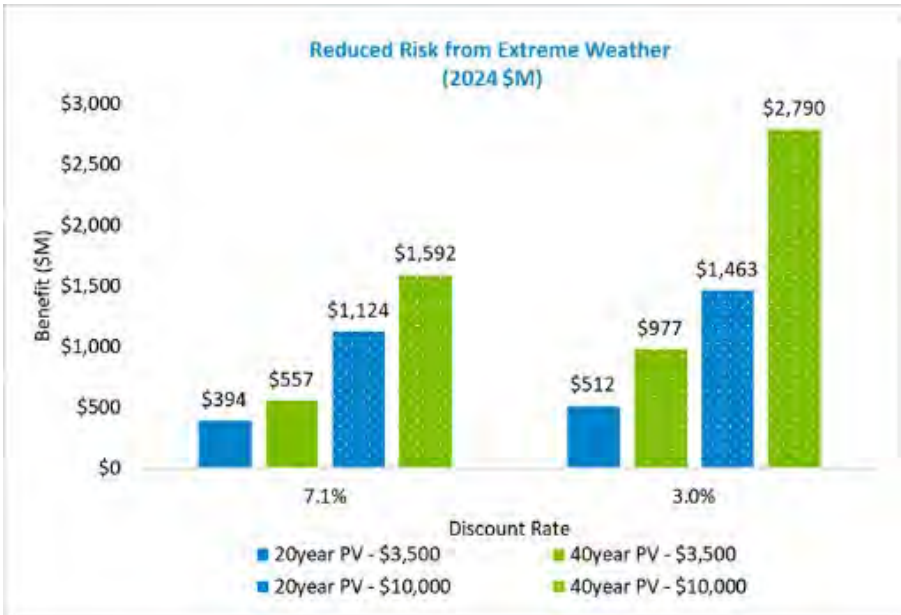


Figure 2.141: Reduced Risk from Extreme Weather Benefit Value

Avoided Capacity Cost

High-Level Methodology Overview

Avoided Capacity Cost (ACC) benefits capture savings in resource investment that result from the increased transfer capability to enable access to a more geographically diverse pool of resources. Transmission constraints limit access to resources elsewhere in the region, requiring more resource investment to meet future capacity needs. The addition of Tranche 2.1 projects alleviates the constraint violations and avoids the need for more capacity above what is included in the Future 2A scenario.

The analysis method first identifies the additional reserve requirement by using a simplified transmission constraint model that represents a change in zonal transmission limits and applies probabilistic Loss of Load Expectation (LOLE) analysis. This determines the additional reserves needed to achieve the same level of LOLE with and without LRTP using a 1-day-in-10-year criterion (0.1 d/y). The probabilistic LOLE analysis is performed with the PLEXOS software and includes the evaluation of 14 weather years of load and renewable generation profiles. Hourly simulations are run with 150 samples to reflect the probabilities of forced outages, including temperature-dependent correlated outages. Planned maintenance is also accounted for, using maintenance outage rates and maintenance frequency.

The LOLE analysis is performed using the 2042 seasonal capacity import/export limits (CIL/CEL) values without the portfolio to compute the LOLE for the modeled resources, and an incremental amount of perfect capacity (or load) is then added until the 0.1 d/y annual LOLE is reached (Seasonal LOLE targets are also applied to the cases). The same analysis is repeated using the seasonal CIL/CEL values with the LRTP portfolio to determine the incremental amount of capacity needed to reach the 0.1 d/y annual LOLE. The difference is calculated as the additional reserves that would be needed without the portfolio, reflecting the impact of the LRTP transmission.

This additional reserve value is then applied as an adjustment to the planning reserve margin (PRM) requirement in an incremental EGEAS resource expansion analysis that determines the amount and types of

resources that are built to meet the added requirements. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in, starting with the assumed portfolio in-service year and increased to the full value in the 2042 study year. The EGEAS expansion for this metric is performed in combination with the Capacity Savings from Reduced Losses (CSRL) metric to reflect the total impact of the LRTP Tranche 2.1 portfolio. The ACC and CSRL components are split out after modeling completes, in proportion to their contribution to the total reserve requirement adjustment in 2042.

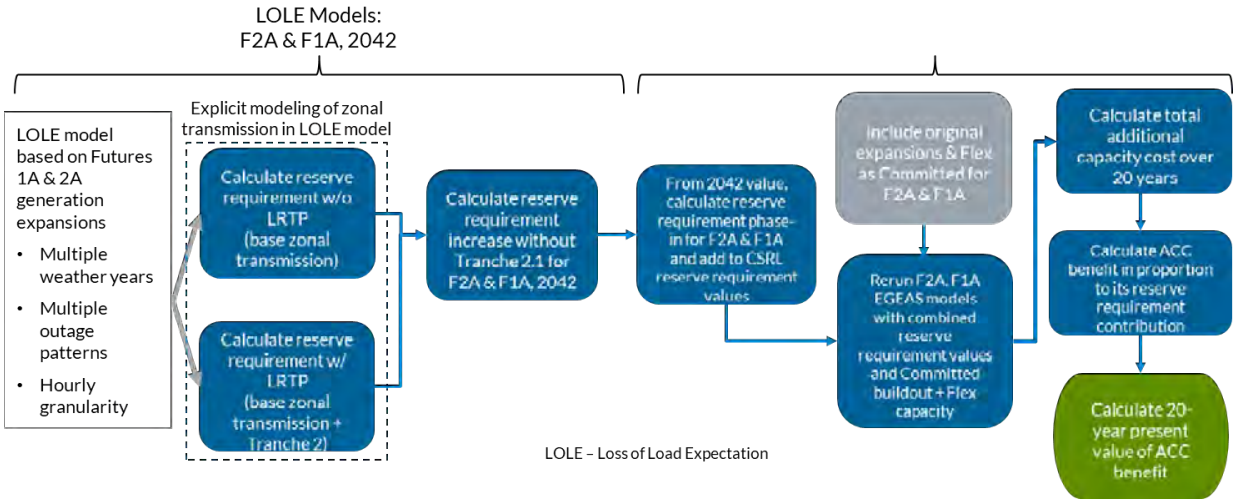


Figure 2.142: Avoided Capacity Costs Calculation Process

Results

Analysis of the Avoided Capacity Costs benefit indicate that the LRTP Tranche 2.1 portfolio increases transfer capability, which enhances resource diversity by allowing access to resources across the region. This provides for a more cost-effective buildout of regional resources and avoids the need for 20.5 GW of capacity that would otherwise be needed in addition to the buildout reflected in Future 2A. The ACC metric delivers benefits of $16.3B – $19.2B over a 20- to 40-year period.

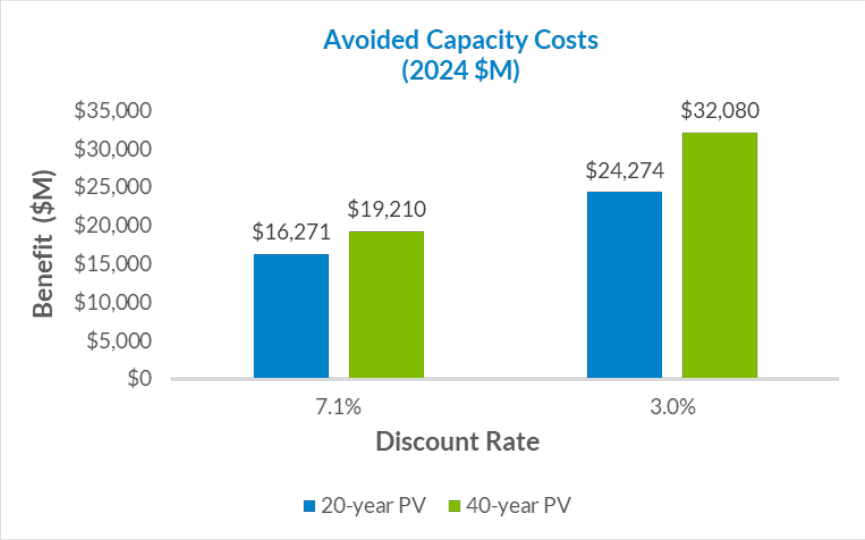


Figure 2.143: Avoided Capacity Costs Benefit Value

Capacity Savings from Reduced Losses

High-Level Methodology Overview

The Capacity Savings from Reduced Losses (CSRL) benefit reflects the capacity savings associated with the reduced losses resulting from the addition of LRTP Tranche 2.1. These projects lower the effective system impedance and redistribute flows to decrease system losses. The adoption of more widely dispersed and remote resources in the future will cause power to flow extensively and over longer distances on the transmission network, producing significant power losses. These losses, occurring during the period with highest capacity requirements, contribute to the need for additional capacity investment. In modeling system requirements for capacity expansion modeling, losses are included in the load forecast data and are held constant when evaluating Avoided Capacity Cost benefits (i.e., the benefit metric does not account for the change in losses with and without LRTP transmission). Capacity Savings from Reduced Losses (CSRL) captures an incremental benefit where LRTP transmission reduces losses in the peak capacity period.

The methodology applied in the calculation of CSRL examines change in losses observed in the reliability power flow models that reflect the various seasonal loading conditions. These reliability power flow cases model both without-LRTP topology (higher losses) and with-LRTP topology (lower losses). The change in losses is calculated using the power flow models that correspond to the season with the peak capacity requirements that determine the capacity investment needed to meet Future 2A needs. For Future 2A expansion, the winter season was determined to have the highest capacity requirements.

The modeling of incremental losses in the EGEAS expansion is reflected as a reserve requirement adjustment to introduce the additional requirements in the resource expansion. While reserve requirement itself is not a function of system losses, it simply serves as mechanism to capture the effects of losses by introducing additional requirements for capacity. The additional reserve requirements for Capacity Savings from Reduced Losses are added to the reserve requirements from the Avoided Capacity Cost metric and applied as a PRM adjustment in an incremental EGEAS expansion. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in starting in the assumed portfolio in service year and increased to the full value in the

2042 study year. The EGEAS expansion results reflect the total impact of the LRTP Tranche 2.1 portfolio and the components for each metric are split out after the fact in proportion to their contribution to the total reserve requirement adjustment in 2042.

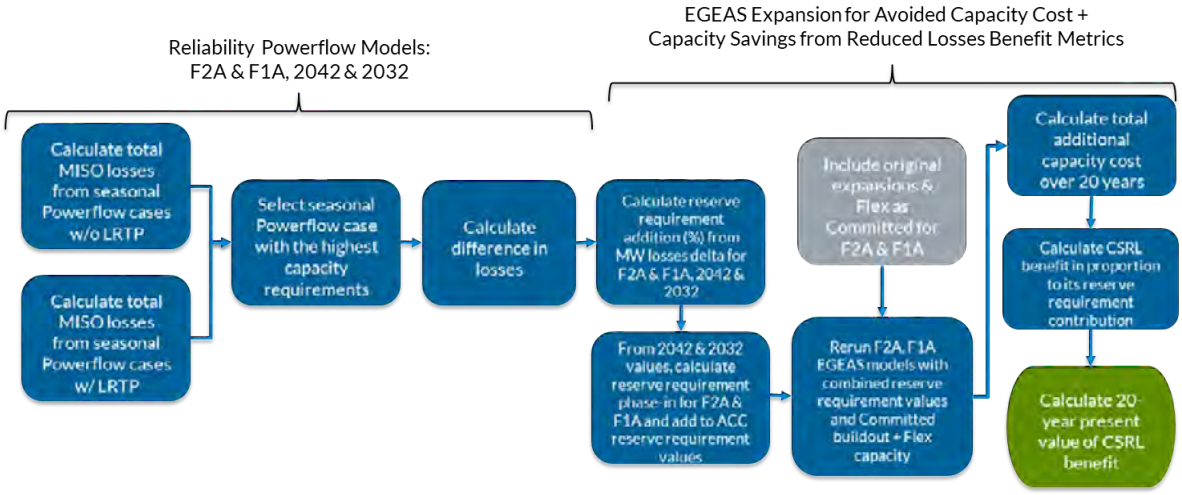


Figure 2.144: Capacity Savings from Reduced Losses Calculation Process.

Results

The lower capacity requirements resulting from the decrease in transmission system losses with the LRTP Tranche 2.1 portfolio avoids the need for 2.3 GW more capacity investment which yields benefits of $1.9B - $2.2B over a 20- to 40-year period.

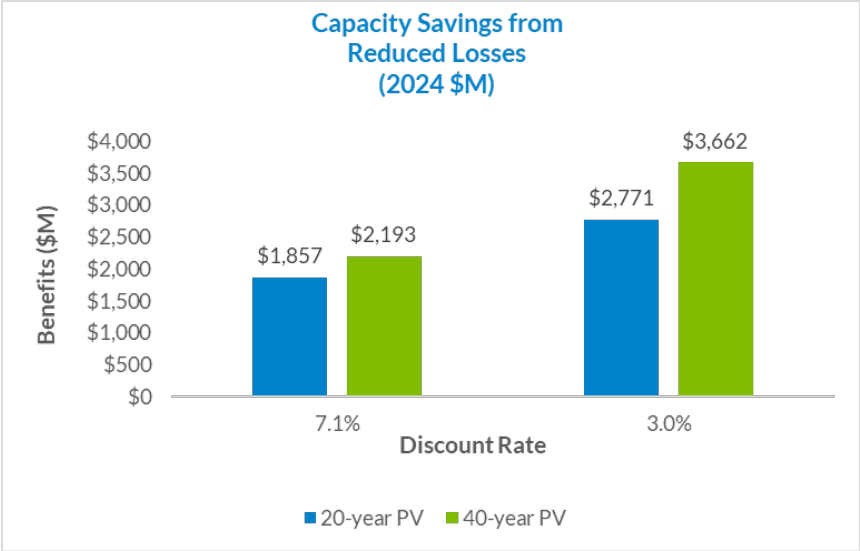


Figure 2.145: Capacity Savings from Reduced Losses Benefit Value.

Avoided Transmission Investment

High-Level Methodology Overview

Avoided Transmission Investment benefits reflect the capital cost savings from eliminating the need for age and condition replacement of existing facilities where LRTP projects reuse existing transmission infrastructure. LRTP projects that require rebuild of existing facilities or co-location of new transmission circuits along the same route as the existing facilities would require installation of new structures and hardware to support both the new circuit as well as the existing circuit and eliminates the need to replace the aging facility later resulting in avoided costs. Candidate facilities for age and condition replacement are identified in the LRTP project scoping effort. These selections are then evaluated for replacement cost except where Transmission Owners have determined that the facilities are ineligible for age and condition replacement due to recent construction or rebuild. Costs are estimated using high level cost estimates derived from the current MISO Transmission Cost Estimation Guide.

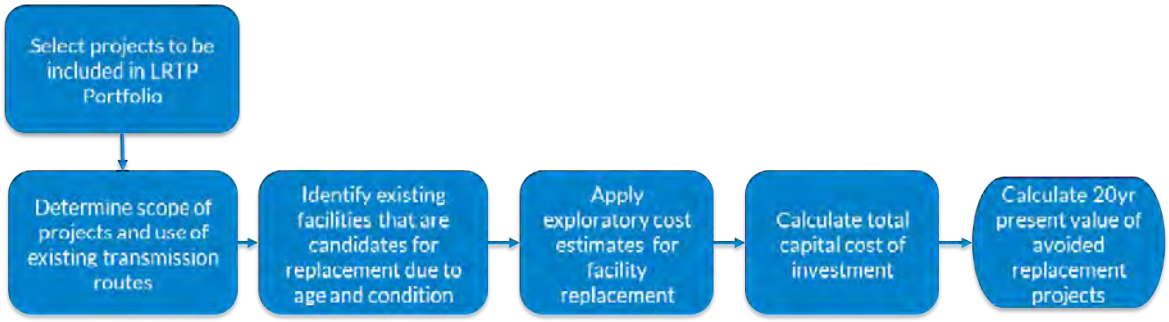


Figure 2.146: Avoided Transmission Investment Calculation Process.

Results

LRTP Tranche 2.1 portfolio avoids the need for replacement of over 700 miles of existing transmission and delivers benefits of $1.2B - $1.8B over a 20- to 40-year period.

Equipment and Upgrade Type	Unit Cost ($M)	Quantity /Miles	Cost ($M)
Transformer Replacement =345	$12.00	0	$0.0
Transformer Replacement <345	$8.40	0	$0.0
Transmission line Replacement =345kV (per mile)	$3.20	178	$569.6
Transmission line Replacement <345kV (per mile)	$1.90	424	$805.6
Transmission double-ckt line replacement = 345 (per mile)	$3.24	30	$97.2
Transmission double-ckt line replacement <345 (per mile)	$2.60	75	$195.0
Transmission triple-ckt line replacement <345 (per mile)	$2.64	1	$1.9
		Total (2024$)	**$1,669.3**

Table 2.30: Summary of Avoided Transmission Investment Benefits

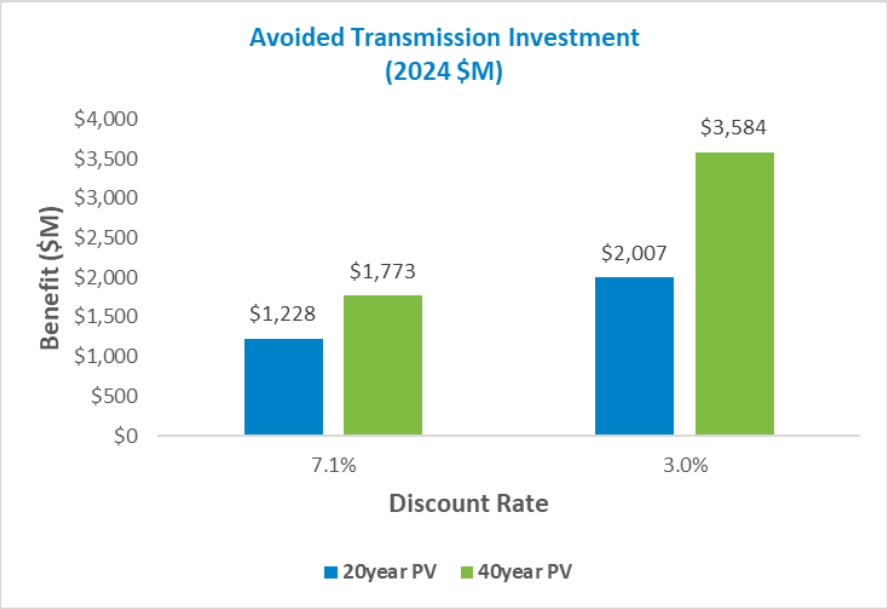


Figure 2.147: Avoided Transmission Investment Benefit Value.

Congestion and Fuel Savings

High-Level Methodology Overview

The congestion and fuel savings benefit reflects production cost savings that are achieved through a more economically efficient dispatch enabled by regional transmission, which reduces congestion and provides access to lower-cost generation. Production cost analysis uses hourly (8760) chronological security constrained unit commitment and economic dispatch, adhering to a wide variety of operating constraints and respecting N-1 contingency conditions. Production cost savings calculations compare the reference case dispatch using a model without the LRTP transmission portfolio to a change case dispatch that incorporates the LRTP transmission portfolio. The addition of LRTP transmission decreases the loading (congestion) on the pre-existing network, alleviating several thermal constraint violations that would otherwise necessitate dispatch of higher-cost resources and facilitates access to lower-cost generation. The difference in production costs between the reference case and change case is thus captured as a benefit provided by the LRTP portfolio.

MISO's production cost models do incorporate Production Tax Credits (PTC) (See MISO Series 1A Futures Report - Inflation Reduction Act) for applicable resources into the security constrained unit commitment and economic dispatch; however, the PTC value is removed from the final congestion and fuel savings value shown for the transmission portfolio.

Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of adjusted production costs (by zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of adjusted production costs (by Cost Allocation Zone) with LRTP transmission for the three study years.

For the three study years, the difference in Adjusted Production Costs with and without LRTP transmission is calculated to produce an annual savings. These yearly values are then used to interpolate or extrapolate annual values for the remaining years within the benefit period.

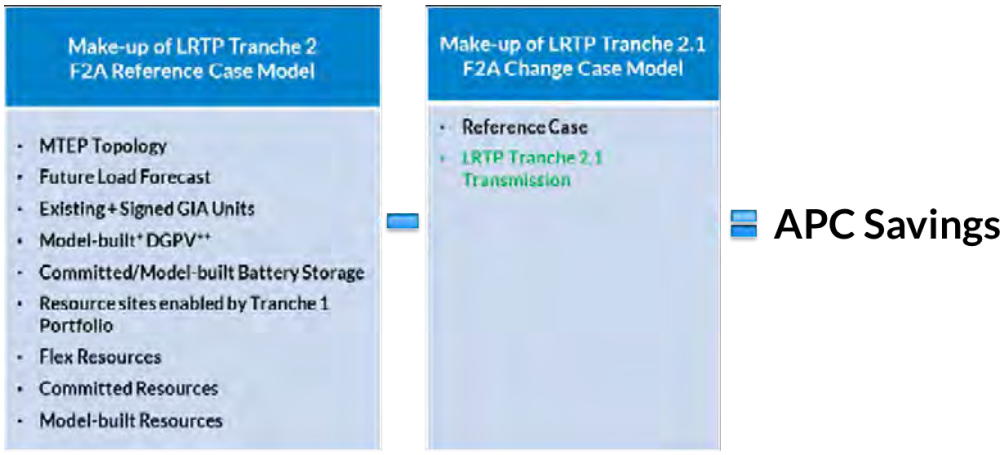


Figure 2.148: APC Savings

Results

The LRTP Tranche 2.1 Portfolio alleviates transmission constraint violations and reduces congestion to allow more efficient dispatch of lower cost resources which provides benefits of congestion and fuel savings benefits of $8.1B - $11.3B over a 20- to 40-year period.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**7.1%**	**3.0%**	**7.1%**	**3.0%**
CAZ				
1	$1,366	$2,236	$2,856	$6,876
2	$2,546	$3,698	$3,888	$7,809
3	$1,689	$1,932	$1,000	-$326
4	-$341	-$407	-$255	-$121
5	$232	$433	$645	$1,727
6	$1,847	$2,612	$2,607	$4,922
7	$808	$940	$531	$31
Total	**$8,148**	**$11,443**	**$11,272**	**$20,916**

Table 2.31: Distribution of Congestion and Fuel Savings Benefits

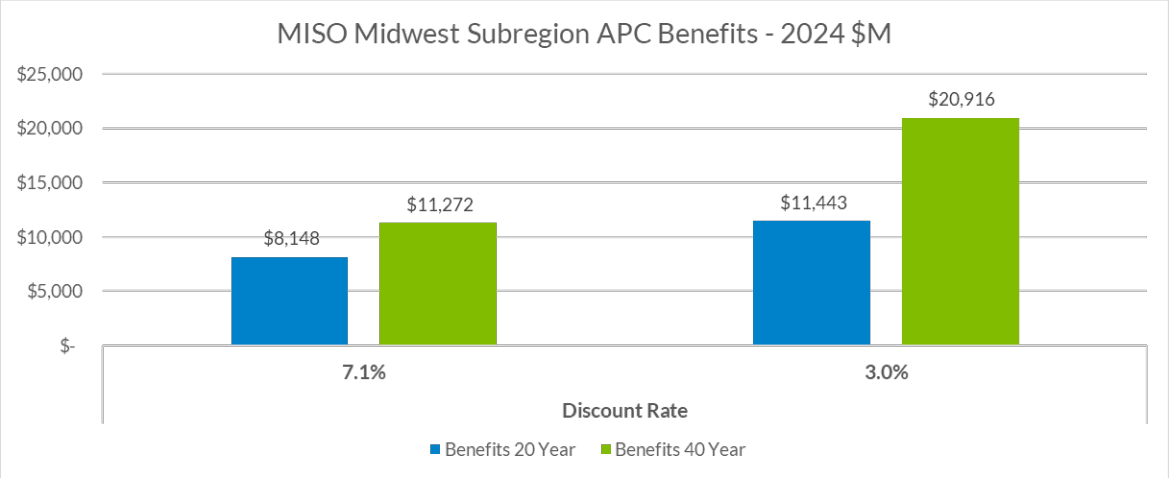


Figure 2.149: Congestion and Fuel Savings Benefit Value

Energy Savings from Reduced Losses

High-Level Methodology Overview

Energy Savings from Reduced Losses captures the lower production costs that result from the addition of transmission facilities that reduces the overall system losses. Transmission losses that are produced by flow of power across the transmission network contribute to the energy requirements and increase the overall costs of energy to customers. As the resource fleet transitions to utilize more dispersed generation in remote areas of the footprint, losses increase with the more extensive use of the transmission network and transport of power over longer distances further increasing energy costs.

The addition of new transmission facilities provides additional transmission capacity and lowers the effective system impedance which will result in a decrease in real system losses. These real losses are modeled as constant values within the load profiles used in the standard production cost simulations. Thus, production cost savings generally do not capture the incremental benefits of reduced losses provided by the addition of new transmission elements. The production cost model case can be modified to reflect the reduction in losses, estimated from the power flow cases and applied to the demand in the change case which includes the new transmission. The Adjusted Production Costs (APC) savings are calculated using a reference and change case model pair with base case losses in the reference case and the change case reflecting the estimated reduction in losses. The difference between those two APC values is the APC savings from reduced losses resulting from the transmission expansion.

The differences in losses are calculated with and without the LRTP Tranche 2.1 portfolio for the four 2032 and four 2042 core power flow models. Loss reduction values are averaged across all core models for each study year and compared to the average demand in the MISO Midwest subregion to determine an average percentage of load as a scaling factor. This scaling factor is used to adjust the load profiles in the change case economic models to reflect the reduced loss component.

Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of Adjusted Production Costs (by zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of Adjusted Production Costs (by Cost Allocation Zone)

with LRTP transmission for the three study years. The difference in APC between the change case containing the additional loss component and the reference case without the reduced losses provides the total APC savings when reduced loss energy is applied. The APC savings attributable to reduced loss energy is determined by netting out the value of the base Congestion and Fuel Savings metric.

$$APC\ Savings\ from\ Reduced\ Loss\ Energy = (Baseline\ Reference\ Case\ APC - Reduced\ Loss\ Energy\ Change\ Case\ APC) - (Baseline\ Reference\ Case\ APC - Baseline\ Change\ Case\ APC)$$

For the three study years (2032, 2037, and 2042), the annual production cost savings from reduced losses are used to interpolate or extrapolate annual values for the remaining years within the benefit period.

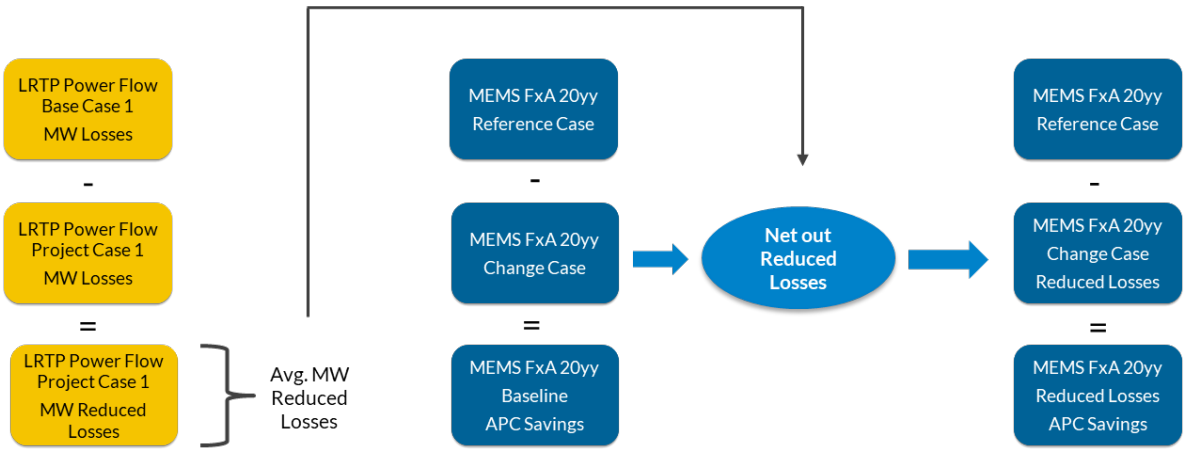


Figure 2.150: Energy Savings from Reduced Losses Calculation Process.

Results

The LRTP Tranche 2.1 Portfolio provides additional transmission capacity and redistributes flows to reduce system losses which delivers energy savings from reduced losses benefits of $1.6B - $2.4B over a 20- to 40-year period.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**7.1%**	**3.0%**	**7.1%**	**3.0%**
CAZ				
1	$246	$361	$388	$799
2	$273	$376	$356	$626
3	$54	$102	$153	$413
4	$92	$143	$168	$379
5	$129	$180	$176	$323
6	$428	$598	$584	$1,069
7	$411	$571	$551	$993
Total	**$1,632**	**$2,332**	**$2,376**	**$4,602**

Table 2.32: Distribution of Energy Savings from Reduced Losses Benefits

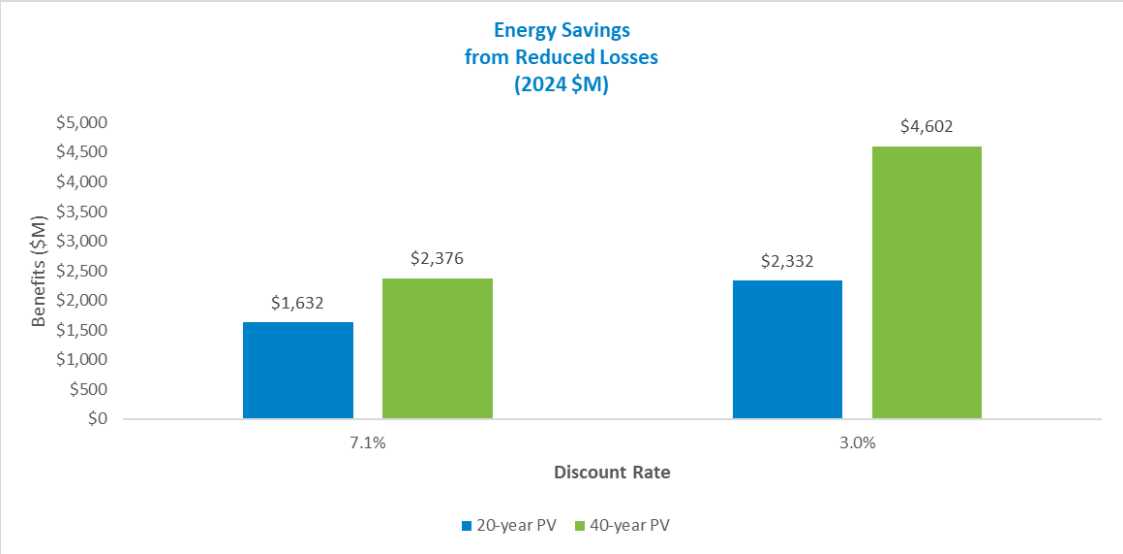


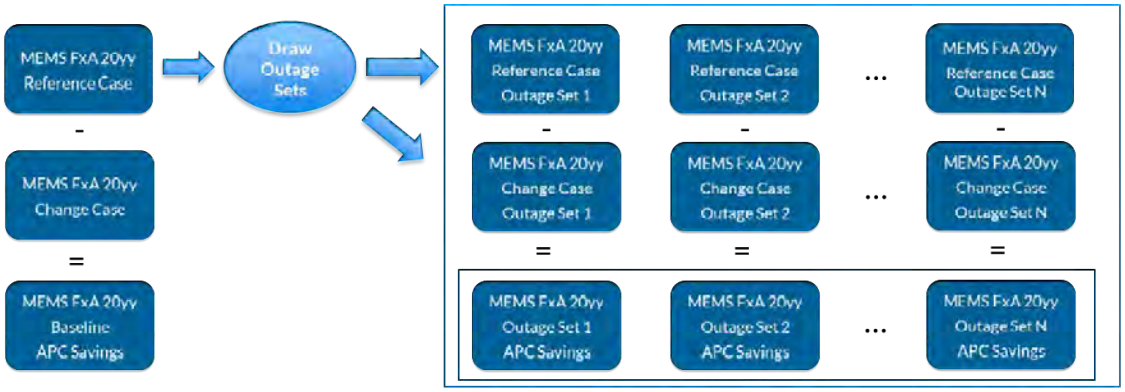
Figure 2.151: Energy Savings from Reduced Losses Benefit Value.

Reduced Transmission Outage Costs

High-Level Methodology Overview

Reduced Transmission Outage Costs captures incremental savings that more fully reflect the effects of congestion under actual operating conditions. Congestion and fuel savings benefits apply conservative modeling of system conditions that reflect an intact transmission network. Throughout the year there are typically numerous planned and forced transmission outages that occur with varying degrees of overlap. These facility outages remove available transmission capacity from the system, increase the loading on remaining in-service facilities, and contribute to congestion. The addition of LRTP transmission unlocks additional value by relieving the additional congestion attributed to typical planned and forced outage schedules.

Outage sets are created by applying outage probabilities established from historical transmission outage records to prepare annual profiles of random outage draws for modeled transmission elements on a daily basis for forced outages and on a monthly basis for planned outages. Ten outage sets are developed to reflect a range of different outage schedules. For each of the three study years (2032, 2037, and 2042), the difference in APC with and without LRTP is calculated to produce an annual savings that captures the effects of the randomized sets of planned and forced outages. For each of the three study years, the production cost savings are averaged across the 10 outage simulation runs to reflect annual savings for a typical year of outages. The APC savings attributed to the outage impact is determined by netting out the base Congestion and Fuel Savings, and the values for the three study years are used to interpolate or extrapolate the annual values for the remaining years within the benefit period.



$$Reduced\ Transmission\ Outage\ Costs = \frac{\sum_n Outage\ Set\ n\ APC\ Savings}{N} - Baseline\ APC\ Savings$$

Figure 2.152: Reduced Transmission Outage Costs Calculation Process

Results

The LRTP Tranche 2.1 Portfolio provides additional transmission capacity that helps to enhance operational flexibility and reduce congestion that occurs from typical outage schedules which provides Reduced Transmission Outage Costs benefits of $76M - $110M over a 20- to 40-year period.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**7.1%**	**3.0%**	**7.1%**	**3.0%**
CAZ				
1	$31	$46	$49	$100
2	$14	$16	$8	-$2
3	-$34	-$40	-$26	-$15
4	-$3	-$9	-$18	-$56
5	$69	$90	$75	$106
6	$22	$34	$40	$91
7	-$22	-$27	-$18	-$12
Total	**$76**	**$108**	**$110**	**$211**

Table 2.33: Distribution of Benefits for Reduced Transmission Outage Costs

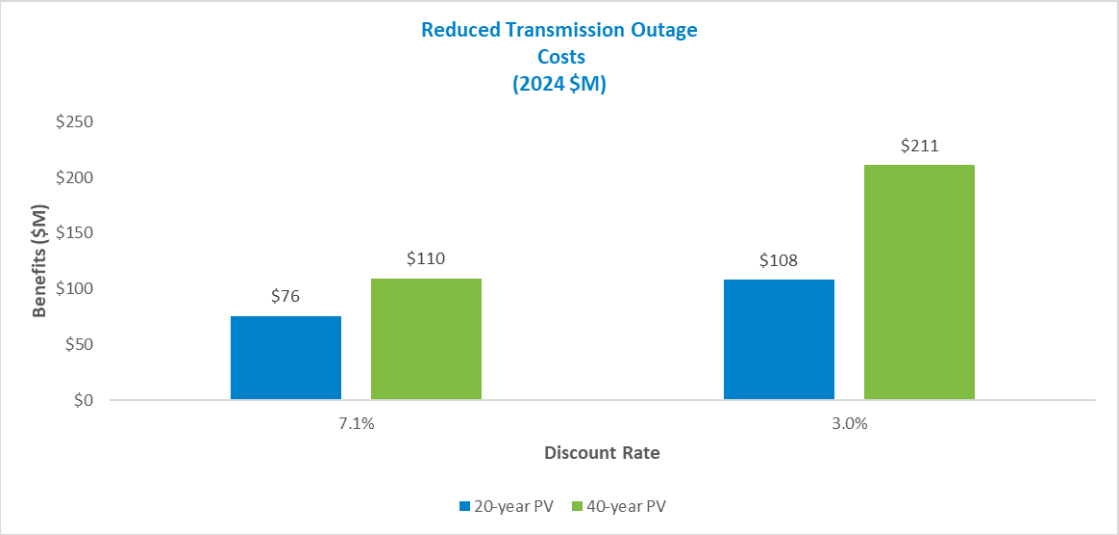


Figure 2.153: Reduced Transmission Outage Costs Benefit Value

Decarbonization

High-Level Methodology Overview

Decarbonization benefits are associated with avoided CO_2 emissions that result from the more efficient dispatch of lower-cost resources. Production cost simulations are used to economically dispatch resources with respect to availability and subject to transmission constraints and establish the hourly dispatch of resources over 8760 annual hours. The dispatch of lower-cost, non-emitting renewable resources avoids CO_2 emissions for the generation fleet. As transmission congestion occurs on the system, dispatchable carbon-emitting resources are needed to manage system flows and can displace carbon-free renewable energy, leading to higher levels of CO_2 emissions. The addition of LRTP transmission alleviates congestion, allowing dispatch of more renewable energy that provides benefits through avoided carbon emissions.

Analysis of Decarbonization benefits uses the emissions data from the Adjusted Production Cost (APC) analysis used for the base Congestion and Fuel Savings benefit metric and compares the change in CO_2 emissions between the reference case without LRTP and the change case with LRTP. Values are computed for years 2032, 2037 and 2042; and are interpolated for years in between and extrapolated for years beyond 2042. The reductions in annual CO_2 emissions are converted to metric tons and monetized by applying a range of carbon prices that reflect the value of decarbonization.

	Federal	MN PUC
2024$/metric ton	$85	$248.67

Table 2.34: Carbon Costs for Monetization of Benefits

Results

The LRTP Tranche 2.1 portfolio alleviates congestion, allowing for more efficient dispatch of non-emitting resources to reduce CO_2 emissions by 127-199M metric tons over 20 to 40 years. This provides Decarbonization benefits of $7.2B - $9.0B over a 20- to 40-year period.

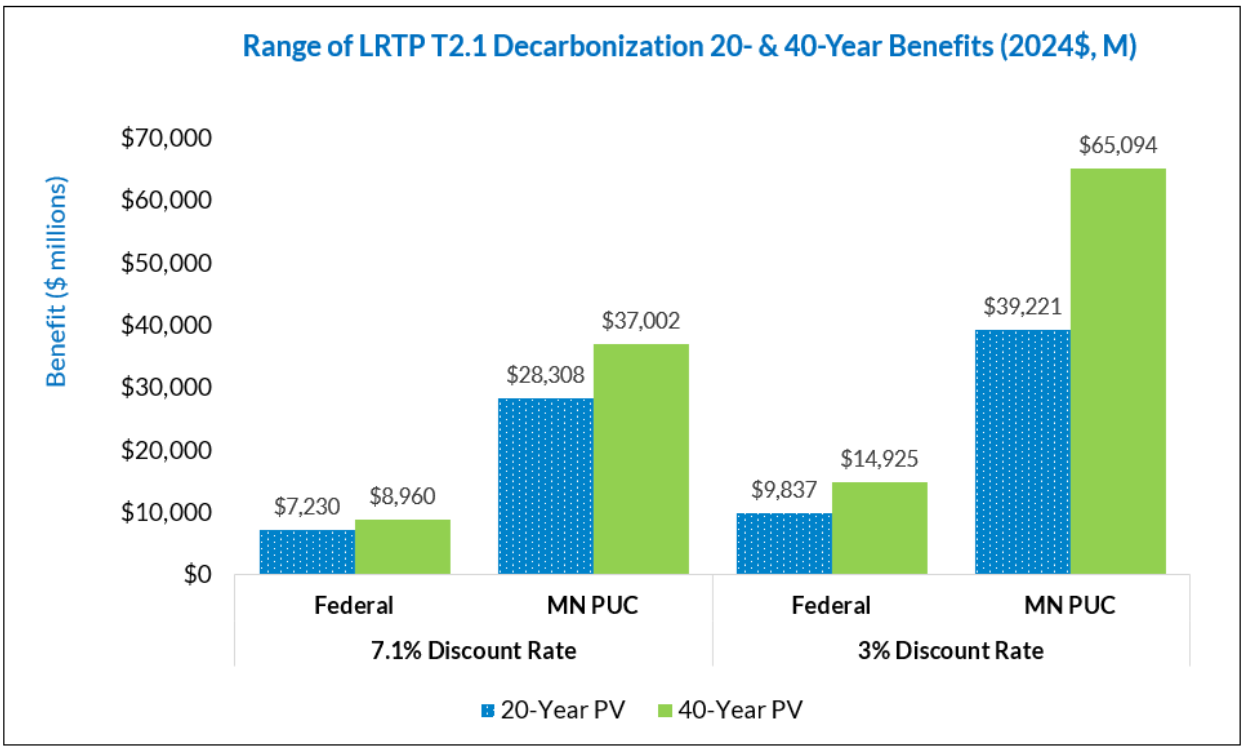


Figure 2.154: Decarbonization Benefit Value.

Future 1A Benefit Metric Analysis

The benefits metrics for the LRTP Tranche 2.1 portfolio were evaluated with Future 1A assumptions to assess value in a lower-bookend scenario applying the same methodologies used for Future F2A. The analysis demonstrates that under the Future 1A scenario, the LRTP Tranche 2.1 portfolio delivers benefits in excess of costs, totaling $34.2B - $61.9B over a 20-year period with an overall benefit-to-cost ratio ranging from 1.2 to 2.2.

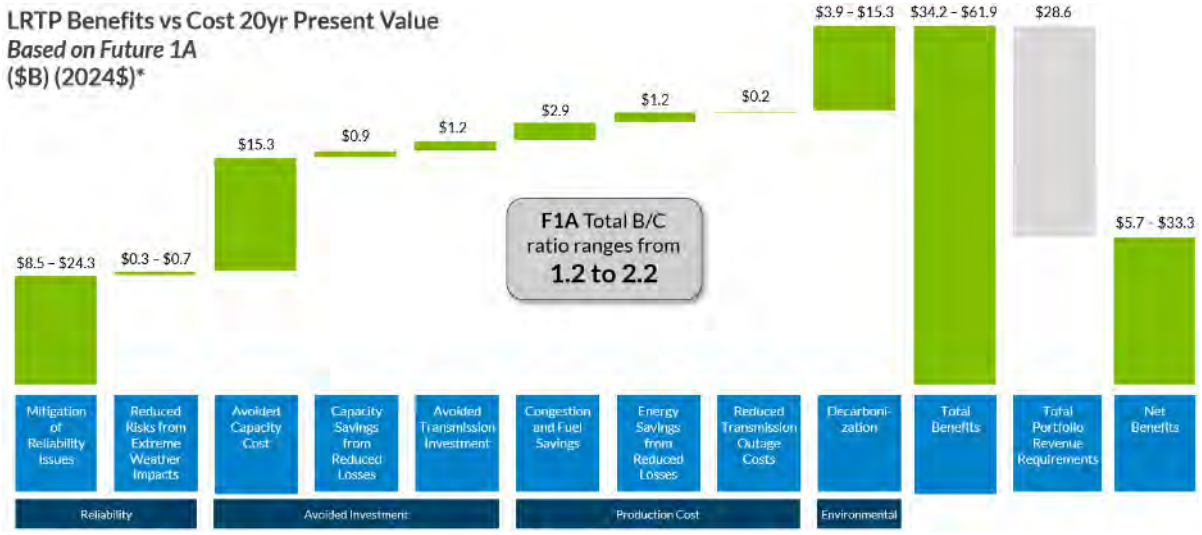


Figure 2.155: Tranche 2.1 Benefits based on Future 1A.

Step 6: Recommend Preferred Solutions

Tranche 2.1 portfolio includes 24 projects and 323 facilities across the MISO Midwest subregion estimated at $21.8 billion and targeted to go in service from 2032 to 2034.

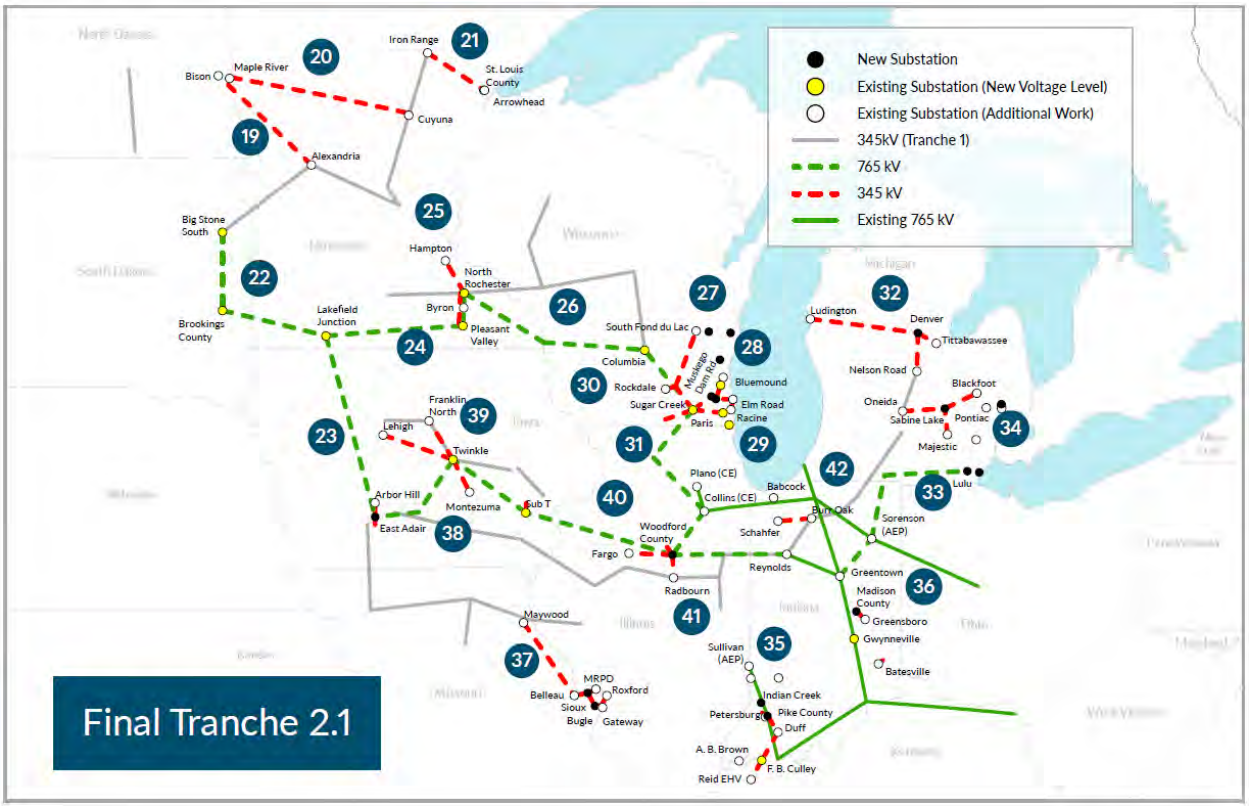


Figure 2.156: Tranche 2.1 Portfolio Map

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
25	Pleasant Valley- North Rochester - Hampton Corner	345	2032	$222
26	North Rochester - Columbia	765	2034	$1,924
27	Rocky Run - Werner - North Appleton	345	2032	$212
28	South Fond du Lac- Rockdale- Big Bend- Sugar Creek - Kitty Hawk	345	2033	$1,102
29	Bluemond - Arcadian - Waukesha- Muskego- Elm Road - Racine	345	2032	$731
30	Columbia- Sugar Creek	765	2034	$743
31	Sugar Creek- Collins	765	2034	$733
32	Ludington- Denver - Tittabawassee & Nelson Road	345	2032	$1,553
33	Greentown - Sorenson - Lulu	765	2033	$1,310
34	Oneida- Sabine Lake- Blackfoot & Majestic	345	2032	$600
35	Southwest Indiana-Kentucky	345	2032	$743
36	Southeast Indiana	345	2032	$578
37	Maywood - Belleau- MRPD - Sioux - Bugle	345	2032	$881
38	East Adair - Marshalltown- Sub T	765	2034	$1,583
39	Lehigh- Marshalltown- Franklin North & Montezuma	345	2032	$588
40	Sub T - Woodford County - Collins & Reynolds	765	2034	$2,298
41	Woodford County - Fargo & Radbourn	345	2032	$422
42	Burr Oak - Schahfer	345	2032	$68
	Total Portfolio Cost		Total	**$21,868**

Table 2.35: Tranche 2.1 Portfolio Projects

Step 7: Apply Appropriate Cost Allocation

Distribution of Benefits and Portfolio Costs

Benefits are spread across the Midwest subregion. The LRTP Tranche 2.1 Portfolio of projects was developed for the MISO Midwest subregion to ensure transmission is reliable, economic, and compliant in the future, given state and utility policy and goals, projected conditions and industry trends. Analysis of the nine benefit metrics included identifying the distribution of each benefit across the Cost Allocation Zones in the Midwest subregion. The distribution of benefits of the LRTP Tranche 2.1 Portfolio is shown to provide benefits in excess of costs for each Cost Allocation Zone (CAZ) under Future 1A and 2A.

Benefit Metric	CAZ Allocation Method
Mitigation of Reliability Issues	Based on location of reliability issues
Reduced Risks from Extreme Weather Impacts	Based on load ratio share
Avoided Capacity Costs	Based on load ratio share
Capacity Savings from Reduced Losses	Based on load ratio share
Avoided Transmission Investment	Based on the zonal location of upgrade
Congestion and Fuel Savings	Derived directly from PROMOD results
Energy Savings from Reduced Losses	Derived directly from PROMOD results
Reduced Transmission Outage Costs	Derived directly from PROMOD results
Decarbonization	Based on load ratio share

Table 2.36: Benefit Metric Method to Distribute Benefits to Cost Allocation Zones

Future 2A

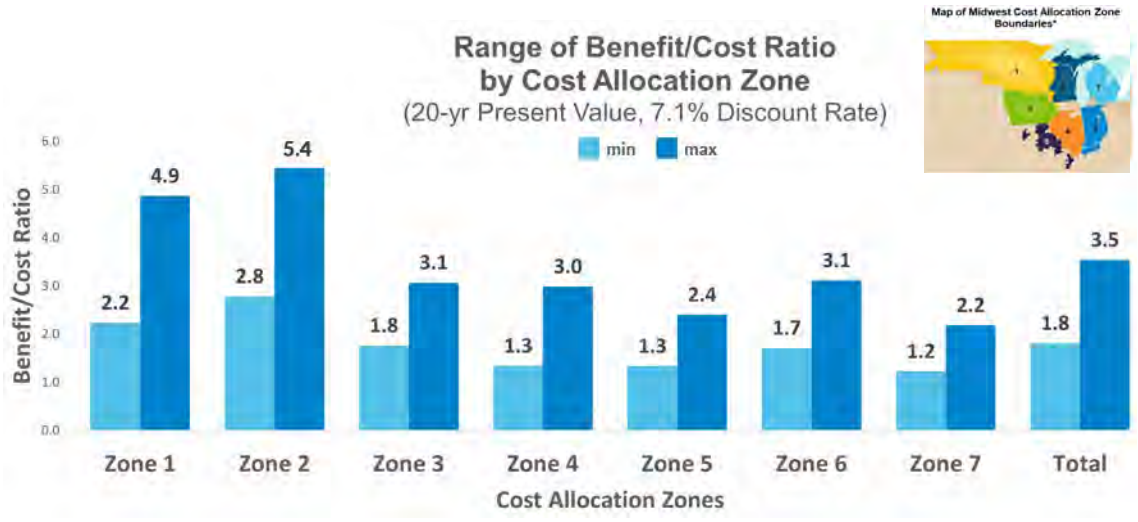


Figure 2.157: Tranche 2.1 Distribution of Benefits – Future 2A

Future 1A

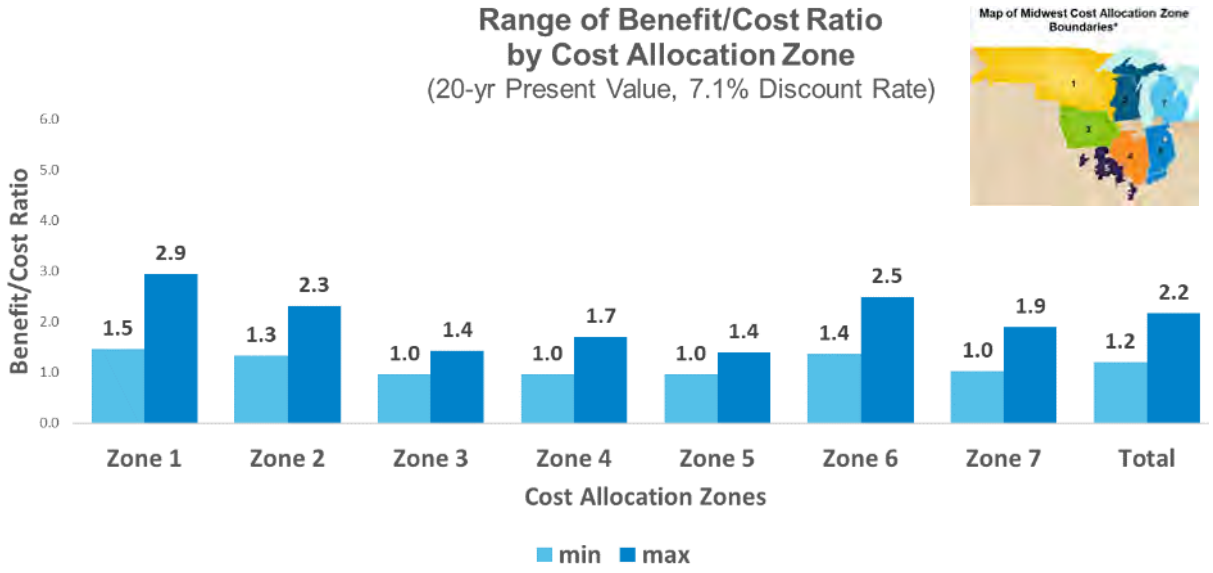


Figure 2.158: Tranche 2.1 Distribution of Benefits - Future 1A[4]

Estimates of MVP Usage Rates for Tranche 2.1 Portfolio

As Multi-Value-Projects, the costs of the LRTP Tranche 2.1 Portfolio will be recovered from MISO load and exports associated with the MISO Midwest subregion through the energy-based MVP Usage Rate ($/MWh). Additionally, indicative annual MVP usage rates for the LRTP Tranche 2.1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. The MVP Usage Rate for Tranche 2.1 is estimated to peak at $6.44 per MWh of energy usage and average $4.76 per MWh over a 40-year period. While the Tranche 2.1 portfolio is estimated to cost MISO members about $5 per 1 MWh or 1,000 kWh of energy used, that investment will provide $10 to $18 of value over that same amount of usage, based on Future 2A analysis.

[4] Min and Max range reflect changes in the assumptions for the value of lost load (Mitigation of Reliability Issues/Reduced Risks from Extreme Weather Impacts) and avoided CO_2 emissions values (Decarbonization).

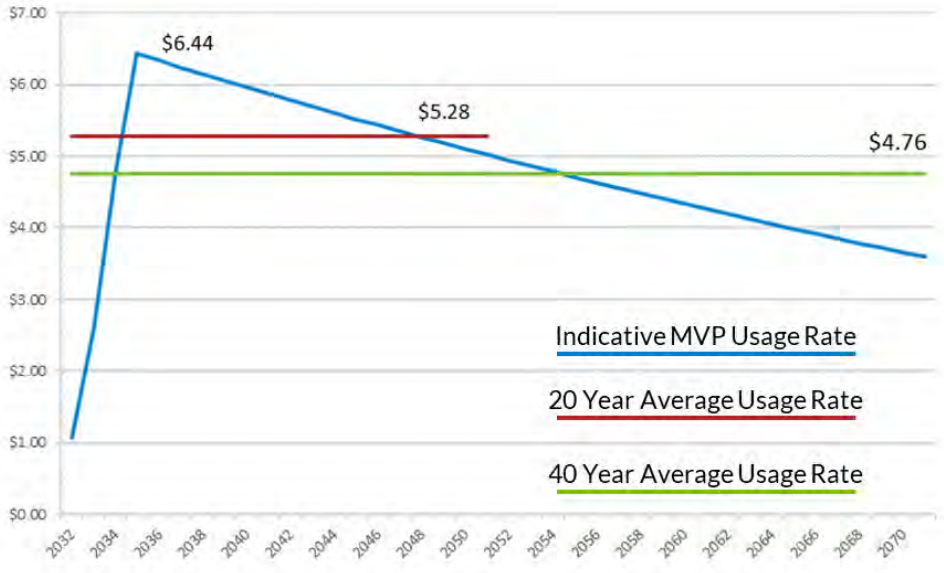


Figure 2.159: Tranche 2.1 Estimated MVP Usage Rate ($/MWh)[5]

Other Benefits

Natural Gas Price Sensitivity

MISO Futures used for the LRTP T2.1 study utilized a new natural gas price forecast methodology. Previous MISO methodologies had used a blend of fixed forecasts, anchored to Henry Hub (HH) price. In the new methodology Gas Pipeline Competition Model (GPCM) was used to develop forecasts that incorporate gas usage from the production cost model runs, to iteratively match both gas usage and price. In this way, gas prices can be calibrated to different Futures assumptions. Gas price base forecasts, used in the EGEAS Futures expansion, were fed into PROMOD, and the gas usage observed in those models was fed into GPCM to create updated price forecasts. This was repeated iteratively until prices between the two models converged, and those converged prices were used in the base PROMOD models. To gain further insight into the impact of gas prices on benefits, an analysis was performed where Future 2A natural gas prices were increased by 20 – 60% above those in the base model, testing both the LRTP reference and change case models. This range corresponds to a range of historical prices seen between 2012 and 2022.

[5] MISO's Schedule 26-A indicative MVP Usage Rate is reflective of rates applied to wholesale electricity transactions and not intended to be used for impacts to retail electricity rates.

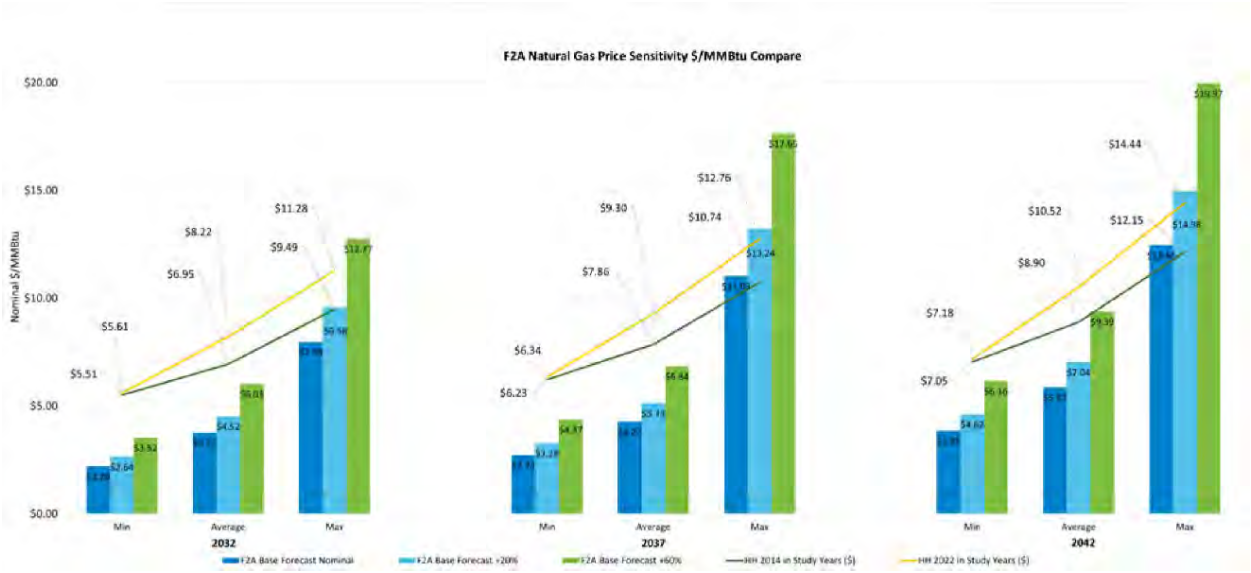


Figure 2.160: Future 2A Natural Gas Price Sensitivity Results

The 20% gas price increase generates a $9.1B congestion and fuel savings, approximately $1B increase in savings, while a 60% gas price increase generates a $10.8B congestion and fuel savings increase, approximately $2.6B increase in savings.

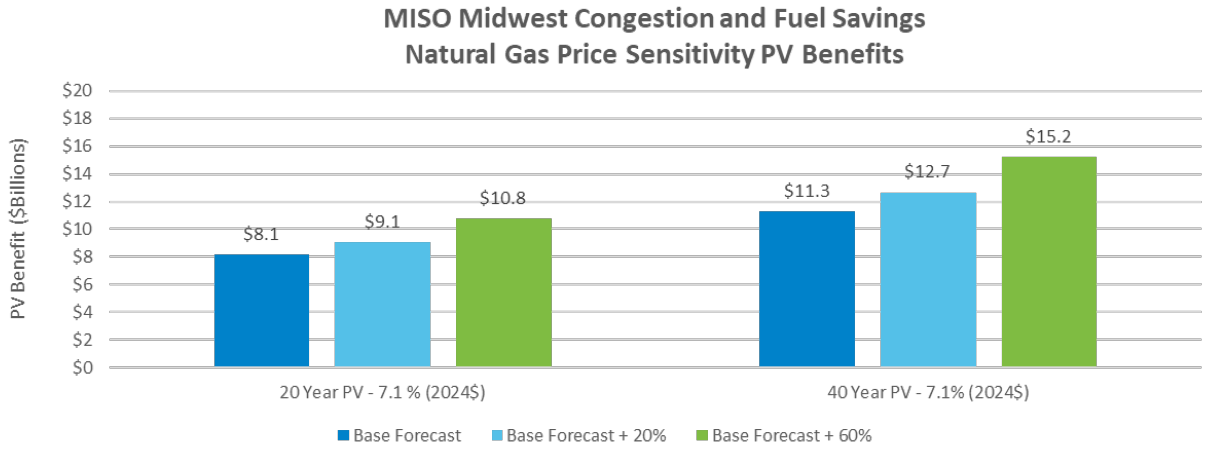


Figure 2.161: Natural Gas Price Sensitivity Congestion and Fuel Savings

Economic Development Benefits

In addition to the direct benefits calculated in the Business Case, Tranche 2.1 transmission investments will also deliver significant economic development benefits to local economies in the MISO region.

Some of these economic development benefits, such as the impact on long-run economic growth, are difficult to quantify. However, as electricity serves as a key input into business production processes, the access to lower and more efficient energy prices provided by transmission investments will support higher

productivity and long-run economic growth. Further, transmission has the potential to attract new businesses and support connections to burgeoning high-growth industries, such as data centers.

Other economic development benefits, such as the short-run impacts on employment and economic output in local economies can be quantified.

Local Investment and Job Creation

Economists typically place the impacts of investments on jobs and economic output into three groupings: direct, indirect, and induced economic activity.

Direct economic impacts refer to impacts in industries directly benefiting from transmission investment, such as construction companies and manufacturers of transmission materials. Indirect economic impacts refer to changes in industries further down the supply chain, such as the suppliers to transmission material manufacturers. Induced impacts refer to changes in the local economy from increased spending on housing, food, and other services by those directly or indirectly employed by the transmission investments.

To arrive at estimates for the potential economic development impacts of Tranche 2.1 investments, MISO surveyed the literature on the impacts of transmission investment on direct jobs, total jobs, and total economic output. MISOs literature survey found that $1 million in transmission investments powers between 1 and 3 direct local jobs, between 2 and 6 total local jobs (including direct, indirect, and induced effects), and between $0.2 and $1.1 million in total local economic output. Ranges were chosen to cover roughly 90% of study estimates found in the MISO literature review.

Using these multipliers, Tranche 2.1 investments are estimated to power roughly 22,000 to 65,000 direct jobs in the MISO region. Direct jobs stemming from Tranche 2.1 investments are also high-quality jobs, with wages estimated to be about 30% higher than a typical worker's wages. Adding in the effects of supply chains and further induced demand and Tranche 2.1 investments are estimated to power between 44,000 and 131,000 total jobs in the MISO region and between $4 and $24 billion in total economic output.

	Tranche 2.1 Investment ($Mns)	Direct Local Jobs		Total Local Jobs		Local Investment/Total Economic Output ($Mns)	
Central		*Low Estimate*	*High Estimate*	*Low Estimate*	*High Estimate*	*Low Estimate*	*High Estimate*
MO	$872	872	2,616	1,744	5,231	$ 174	$ 959
IL	$2,886	2,886	8,659	5,772	17,317	$ 577	$ 3,175
IN	$2,378	2,378	7,135	4,757	14,270	$ 476	$ 2,616
KY	$77	77	230	153	459	$ 15	$ 84
East							
MI	$2,672	2,672	8,015	5,344	16,031	$ 534	$ 2,939
West							
IA	$3,606	3,606	10,817	7,212	21,635	$ 721	$ 3,966
MN	$4,342	4,342	13,026	8,684	26,051	$ 868	$ 4,776
ND	$188	188	564	376	1,129	$ 38	$ 207
SD	$724	724	2,171	1,447	4,341	$ 145	$ 796
WI	$4,086	4,086	12,257	8,171	24,514	$ 817	$ 4,494
Total	$21,830	21,830	65,489	43,659	130,978	$ 4,366	$ 24,013

Table 2.37: Tranche 2.1 Investment by State and Jobs and Economic Impact.

2.3 Near Term Congestion Study Update

Introduction and Background

The first Near-Term Congestion Study was completed in 2023 in response to PAC-2021-1: Address Congestion at Existing Resources. The 2023 study focused on recreating and assessing historically congested flowgates in a near-term PROMOD model. In 2024 this issue was delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Information on stakeholder discussions and presentations on this issue can be found on the MISO website at *PAC-2021-1 Address Congestion At Existing Resources*.

The 2024 Near-Term Congestion Study provided stakeholders the opportunity to submit feedback on various near-term study approaches. The study options presented to stakeholders included:

- Year 5 Economic Model Refinement and Study
- LRTP Tranche 1 Construction Outages Assessment
- Year 2 Economic Model Development and Study

Based on stakeholder feedback and internal MISO interest, MISO moved forward with an LRTP Tranche 1 Construction Outages Assessment for the 2024 Near-Term Congestion Study. This study utilized the Year 5 PROMOD model from the 2023 Near-Term Congestion Study to test and analyze LRTP Tranche 1 construction outages. By partnering with Operations Planning and Competitive Transmission teams internally, and working with our Transmission Owners, outage sequence issues were identified, GETs solutions were requested, and general outage sequence recommendations were developed.

Study Objectives and Scope

The primary objective of this study was to provide insight into the impact of the LRTP Tranche 1 construction outages. Given the magnitude and siting of the LRTP Tranche 1 projects we anticipate temporary increases in congestion and the need for additional coordination with Transmission Owners to identify conflicting outages that could result in reliability issues. By collecting data on these construction outages early and studying them in PROMOD we can provide recommendations on outage sequences.

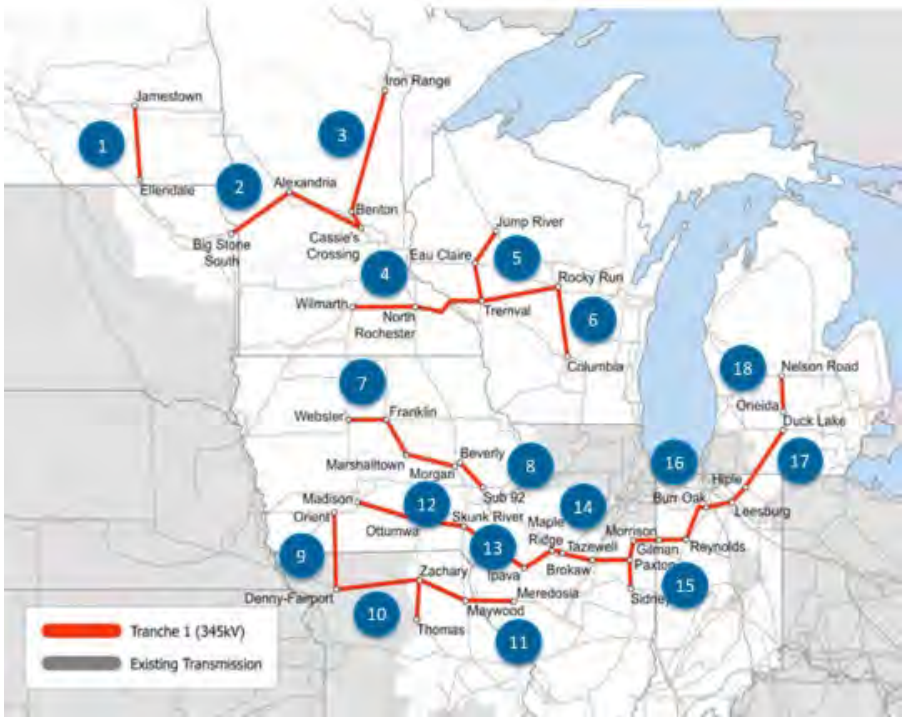


Figure 2.162: LRTP Tranche 1 Portfolio

The 2023 Near-Term Congestion Study model was utilized for this study with adjustments made to reflect random planned and forced, and construction outages.

Model assumptions include:

- Hitachi PROMOD[6] releases
    - Fall 2021 gen updates and economic data
    - Spring 2022 coal prices
    - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
    - Hartburg – Sabine was removed
    - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Operations Planning and Competitive Transmission teams supported the collection of outage information from Transmission Owners required for the study. Outage data was submitted directly to MISO teams through the MTEP Quarterly Update report and CROW. Operations Planning teams provided general guidelines and helped review potential reliability issues in outage information submitted.

General guidelines that have been used to develop and assess outage sequences include:

- Evaluate outages to minimize concurrent outages likely to strand or limit generation outlets.

[6] PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.

- Evaluate outages to ensure that multiple outages do not impact the same interface and interchange as it would create a significant challenge to the system's reliability.
- Review and compare against historical outages that have been challenging for our system.

PROMOD studies are typically conducted with transmission system intact assumptions, excluding the contingencies included in the event file. The Near-Term Congestion Study used a similar methodology to the LRTP Tranche 2.1 Transmission Outages business case metric to create a base random planned and forced outages scenario. This allows us to compare the impact of LRTP Tranche 1 construction outages against more simulated "real-world" conditions. Approximately 2,450 random planned and forced outages were included in all runs with about 250 planned and 2,200 forced outages.

The construction outage scenarios studied include LRTP Tranche 1 construction outage sequences combined with random planned and forced outages. The scenarios studied range from currently planned sequences to worst case scenarios that would present more severe impacts on the system.

Outage sequences from Transmission Owners were incorporated in the testing and study work as they were received. For LRTP Tranche 1 projects where outages were not submitted, Economic Planning estimated outages by utilizing powerflow models and input from Operations Planning and Competitive Transmission teams. Approximately 220 Tranche 1 construction outages were submitted and estimated based on in-service date expectations with about half of those outages occurring in 2027. Figure 2.163 outlines how outages were incorporated to build the scenarios studied.

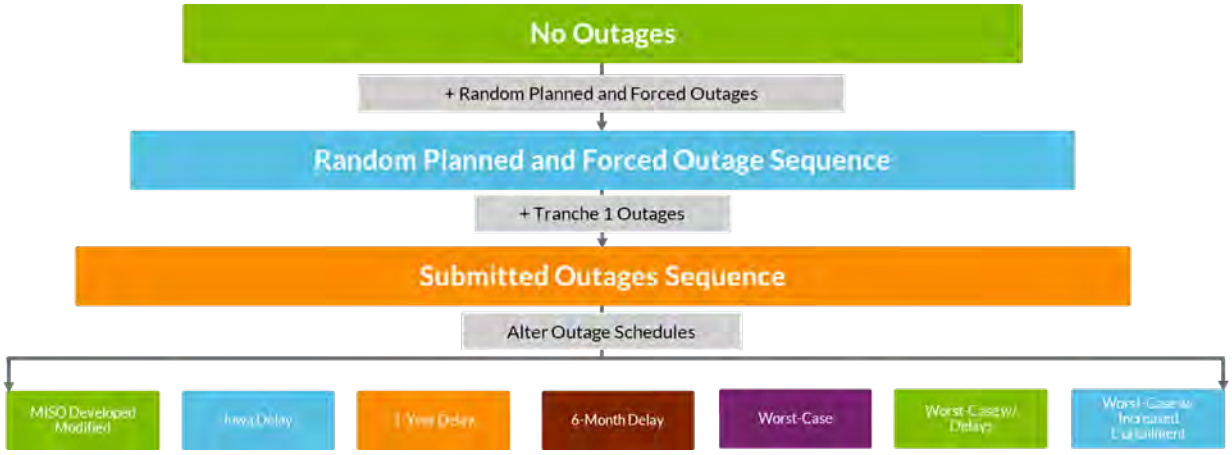


Figure 2.163: Process for Adding Outages and Building Scenarios

Study

Initial Testing

Testing for this study followed a path of simple to complex when it came to identifying outages and how they are included in the model. Initially, specific outages were entered into PROMOD. This worked for small amounts of outages but was not ideal for larger sequences of outages. By utilizing the PDTR (Power Dated Transmission Record) Tool in PAT (PROMOD Analysis Tool) and incorporating the LRTP Tranche 2.1 Transmission Outage business case outage methodology, we were able to come up with a more efficient process for incorporating outages.

Additional testing included comparing runs by Local Resource Zone (LRZ) versus region, and the impact of a larger number of outages within a year timeframe. Much of this testing was done to assess any impacts on runtime. Because PROMOD can only study one year at a time, we started by putting all outages in 2027 to test its capabilities. We then sequenced them between 2025-2030, with consistent lengths, followed by the same test with more realistic lengths. We also split the MISO footprint into multiple areas for these runs to analyze outages at a more localized level. Since we did not encounter any hurdles related to PROMOD run-times or processing, our study remained focused on the full MISO footprint.

Scenarios Studied

All sequences studied included random planned and forced outages and started with the Submitted Outages sequence. Adjustments or alterations were made to specific information in the Submitted Outages sequence relative to that scenario. Scenario descriptions and assumptions are listed below:

Submitted Outages (Base Outages)
Description

- Around 77% of all construction outage data was submitted by Transmission Owners and included in the sequence. The remaining 23% was estimated by the MISO Economic Planning Team with assistance from MISO Operations Planning and Competitive Transmission teams.
- All Iowa outages are estimated due to continued discussions around project ownership.

Assumptions

- Outages not submitted by Transmission Owners were estimated based off Tranche 1 line connection points. Start and end dates for outages were estimated by using in service dates and working with Competitive Transmission group to estimate outage durations.

6-Month Delay
Description

- Construction outages in the Submitted Outages sequence were pushed out by 6 months.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

1-Year Delay
Description

- Construction outages in the Submitted Outages sequence were pushed out by 1 year.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

MISO Developed Modified
Description

- All submitted outage information and estimated outages that were not related to Iowa projects.
- Outages for estimated construction outages were adjusted due to various combinations of outages possible using engineering judgement.

Assumptions

- Adjustments were developed by taking the initial outage schedule and flipping it. The right pieces would still connect by making sure that certain outages followed one another while still ensuring that dates would be changed. Projects remained the same length of time.
    - For example: Outage A to B is from January to June and Outage C to D is from July to December. After making the adjustments, Project A to B is now from July to December and Project C to D is now from January to June. This ensures that outages are left in the same time frame but mixes up concurrent outages.

Iowa Delay

Description

- Outages related to Iowa projects were pushed out beyond the 2027 study year.

Assumptions

- Construction was assumed to be delayed due to ongoing discussions around Iowa project ownership. Outages were pushed out to 2028 and beyond.

Worst-Case

Description

- Outages are sourced from the Submitted Outages scenario but adjusted to all occur in 2027.

Assumptions

- Outages originally scheduled for 2027: These dates remain unchanged.
- Multi-year outages (e.g., Nov 2025–Feb 2026): These start on a comparable Monday in 2027 and conclude on the last Sunday of 2027.
- Outages originally scheduled outside of 2027: For outages scheduled in other years, we identified the same calendar date in 2027 and determined the corresponding day of the week. Based on this, we adjusted the start or end dates using the guidelines below:
    - Start date adjustments:
        - Outages that originally began on a Tuesday through Thursday were moved to the preceding Monday.
        - Outages that originally began on a Friday through Sunday were moved to the following Monday.
            - If the Monday is a national holiday, the outage is scheduled for the following Monday.
    - End date adjustments:
        - Outages that originally ended on a Monday through Wednesday are moved to the preceding Sunday.
        - Outages that originally ended on a Thursday through Saturday are moved to the following Sunday.
            - If the Sunday is a national holiday, the outage is scheduled for the following Sunday.

Worst-Case w/ Delays

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.

Assumptions

- Similar to the original Worst Case sequence, we assumed that all outages will occur in the year 2027, but with an additional 1 to 2 month delay to the original end dates. To complete this delayed scenario, the end dates for the outages were adjusted as follows:
    - Outages set to end between January and October: A 2-month delay was added to the original end date.

- Outages set to end in November: A 1-month delay was applied.
- Outages set to end in December: These were extended to the last Sunday of 2027.

- For the new end dates, we located the same day of the month in the adjusted period. If the corresponding day fell on a Monday through Wednesday, the outage was set to end on the preceding Sunday. If it fell on a Thursday through Saturday, the outage was set to end on the following Sunday.

Worst-Case w/ Increased Curtailment

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.
- Additional outages are added intended to stress the system and increase curtailment.

Assumptions

- Utilizes assumptions from the Worst Case scenario.
- Additional outages added include:
  - MN & ND:
    - Loss of HVDC lines between Square Butte - Arrowhead
    - Loss of HVDC lines between Coal Creek - Dickinson
    - Loss of MWEX Lines (King - Eau Claire 345 kV, Arrowhead - Stone Lake 345 kV are main two)
    - Loss of lines parallel to MWEX (North Rochester - Briggs Road 345 kV or Hazelton - Hickory Creek 345 kV)
  - AMEREN:
    - Sibley - Overton 345 kV, Zachary - Hughes 345 kV
    - Lutesville - Essex 345 kV
    - Sidney - Rising 345 kV
    - Sub T - Maywood 345 kV
    - McCredie - Burns 345 kV
  - NIPS:
    - Wilton Center – Dumont 765 kV
    - Reynolds – Olive 345 kV
    - Reynolds – Meadow Lake 345 kV ckt 1
- Reynolds – Meadow Lake 345 kV ckt 2

2024 Near-Term Congestion Study Report

All information included in the Near-Term Congestion Study section of this chapter along with final study results and takeaways can be found in the 2024 Near-Term Congestion Study Report on the MISO MTEP website under the Related Documents section.

APPENDIX J

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

2001 EQB ORDER AND RELATED MATERIALS

STATE OF MINNESOTA
ENVIRONMENTAL QUALITY BOARD

In the Matter of the Exemption Application by Minnesota Power for a 345/230 kV High Voltage Transmission Line Known as the Arrowhead Project	**MINNESOTA ENVIRONMENTAL QUALITY BOARD'S FINDINGS OF FACT, CONCLUSIONS, AND ORDER GRANTING EXEMPTION** **MEQB DOCKET NO. MP-HVTL-EA-1-99**

The above-entitled matter came before the Minnesota Environmental Quality Board at a regular meeting on March 15, 2001, pursuant to an application by Minnesota Power for an Exemption from the Power Plant Siting Act for a High Voltage Transmission Line known as the Arrowhead Project.

STATEMENT OF ISSUE

Should Minnesota Power be granted an Exemption from the Power Plant Siting Act for a 345/230 kV High Voltage Transmission Line to be constructed in St. Louis County, Minnesota

Based upon all of the proceedings herein, the Minnesota Environmental Quality Board makes the following:

FINDINGS OF FACT

1. The Findings of Fact of the Administrative Law Judge in his report dated January 29, 2001, are adopted with the following amendments.

2. The second bullet of Finding No. 11 is amended to read and a new footnote 18A is added to read:

   Adding four single-phase 345/230 kilovolt transformers to interface with the 345 kV line. These transformers step up the voltage from 230 kV to 345 kV. The approximate rating of these transformers is 800 MVA. [18A]

   18A. Transcript at 1874.

3. The first sentence of Finding No. 15 is amended as follows, footnote 26 is amended as follows, and the remaining language is unchanged:

15. In all the segments, the 345 kV circuit will consist of two-wire bundled 1272 kcmil ACSR conductor for each of the three phases ~~segments~~ for a total of six. ~~twelve.~~

[26] MEQB EX. 1, at 10. ~~2.~~

4. Finding No. 37 is amended to read:

37. MP will notify the DM&IR railroad when ~~installation~~ construction of the 345 kV HVTL and 115 kV power line will be affecting the railroad's trackage. Similar notification to the Minnesota Department of Transportation will occur when the construction crosses Interstate 35. MP will schedule its construction activities to minimize the ~~affect~~ effect on vehicular traffic.[88] There are no impacts on public services arising out of the Arrowhead Project.

5. Finding No. 38 and footnotes 91 and 92 are amended to read:

38. Electric and magnetic fields (EMF) arise from the flow of electricity and the voltage of a line. The intensity of the electric field is related to the voltage of the line and the intensity of the magnetic field is related to the current flow through the conductors.[89] There are no state or federal standards for transmission line electric fields or magnetic fields.

38A. Electric fields are measured in units called kilovolts per meter (kV/meter). The MEQB has included permit conditions for other transmission lines specifying that maximum electric fields must not exceed 8 kV/meter.[90] The maximum anticipated electric field exposure for the MP transmission line, measured directly under the HVTL, is approximately 6.1 ~~6.5~~ kV/meter.[91] ~~Within~~ At a distance of 100 feet of the centerline of the HVTL, the electric field strength nears zero. [92]

[91] MEQB Exhibit 17 at 4.; ~~DLV-1, Sheets 1-6.~~

[92] Id. at DLV –1, Sheets 1-6.

6. Finding No. 39 and footnote 94 are amended to read:

39. ~~EMF is also~~ Magnetic fields are measured in milligauss (mG). Common electrical appliances produce ~~EMF~~ magnetic fields while in operation, as do HVTLs. The Arrowhead Project will increase ~~EMF~~ exposures to magnetic fields for persons living along the right of way above current ~~EMF~~ levels.[93] The amount of the increase ~~is small,~~

~~ranging~~ ranges from approximately 50 mG at the edge of the right of way to approximately 10 mG at the distance of the nearest home to the Arrowhead HVTL, which is approximately 160 feet.[94] These increased levels occur at the periods of peak flow and are present approximately 5% of the time.[95]

[94] By way of comparison, an electric stove emits ~~an EMF~~ a magnetic field of 21.6 mG at a distance of one foot. A person making a photocopy is exposed to ~~an EMF~~ a magnetic field of 31 mG. MP-17; DLV-6. The 160 feet figure for the distance to the nearest home is found at Tr. at 314.

7. Finding 48 is amended to change the last sentence to read:

The expansion of the existing right of way for that segment has no significant human or environmental impact.

8. Finding No. 49 is amended to read:

49. The other alteration to the right of way for the Arrowhead Project moves the 0.8 miles of the existing route to the eastern side of the DM&IR rail yard. The change is proposed at the request of the landowners along the existing route. ~~, the DM&IR railroad.~~ The movement of the 0.8 mile length of right of way does not result in significant human or environmental impact. Removing the existing 0.8 mile segment of 115 kV power line from its existing location is a benefit to persons living in the eastern portion of Gary. The Arrowhead Project uses existing rights-of-way to minimize the impact of upgrading the existing 115 kV power line to a 345 kV HVTL.

9. Finding 54 is amended to read:

54. The Arrowhead Project will not result in a significant impact on human health or the environment in Minnesota from the construction and operation of the proposed transmission line. ~~impose demands on air or water resources~~

Based on the foregoing Findings of Fact, the Minnesota Environmental Quality Board makes the following:

CONCLUSIONS

1. Any of the foregoing Findings more properly designated as Conclusions are hereby adopted as such.

2. The Minnesota Environmental Quality Board has jurisdiction over the subject matter of the hearing pursuant to Minn. Stat. § 116C.57.

3. All relevant substantive and procedural requirements of law and rule have been fulfilled in order to grant an application for exemption from the Power Plant Siting Act.

4. The proposed project, when constructed in accordance with the attached conditions, "will not create significant human or environmental impact" in any of the categories of impact examined under the terms of Minn. Rule 4400.1310.

5. The Applicant has demonstrated that the Arrowhead Project meets the standards for exemption from the Minnesota Power Plant Siting Act process in Minn. Stat. § 116C.57, subd. 5.

Based upon the foregoing Conclusions, the Minnesota Environmental Quality Board makes the following:

ORDER

The Minnesota Environmental Quality Board hereby grants an Exemption to Minnesota Power Company from the requirements of the Minnesota Power Plant Siting Act (Minn. Stat. Sections 116C.51 - .69) for the Arrowhead Project, consisting of construction of a 12 mile long 345 kV/115 kV and 345/230 kV High Voltage Transmission Line (for one segment operated at 115 kV) from the Arrowhead substation to the Wisconsin border, and a corresponding modification of the Arrowhead substation, subject to the following conditions:

1. Minnesota Power shall follow the existing right-of-way now occupied by Lines 22, 131, and 132, except for 0.8 miles of new right-of-way along the DM&IR rail yard and except for additional right-of-way width as described in the application.

2. Minnesota Power shall install the low-noise transformers identified in the application at the Arrowhead substation.

3. Minnesota Power shall limit clearing along the right-of-way to vegetation actually affecting the safe operation of the transmission line. The only new right-of-way clearing shall be the 0.8 mile segment along the rail yard and a 3.2 mile segment along

the Midway segment. No herbicides shall be used for clearance if the landowner objects to use of such methods.

4. Minnesota Power shall remove all construction debris from the right-of-way as soon as construction is completed. Minnesota Power shall implement reasonable measures to provide revegetation of low-growing plants along construction areas.

5. Minnesota Power shall implement measures to minimize erosion and to prevent silt from entering surface waters during construction by installing barriers and using set back zones as necessary. The company shall maintain existing trees along streams to be crossed by the line to prevent changes in water temperature.

6. Minnesota Power shall perform no instream work in the four trout streams to be crossed by the line during the time September 15 to April 30.

7. Minnesota Power shall avoid impacts to any wetlands to be crossed by the line by constructing structures in such areas during the winter months when the wetland areas are frozen. If construction or maintenance must be performed in such areas when the wetland is not frozen, Minnesota Power shall use mats to prevent damage.

8. Minnesota Power shall consult with landowners whose property is to be crossed by the line regarding placement of structures to minimize interference with agricultural operations.

9. Minnesota Power shall obtain all necessary permits from federal and state and local units of government before proceeding with construction.

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.

STATE OF MINNESOTA
ENVIRONMENTAL QUALITY BOARD

Dated: 3/15/01

Gene Hugoson, Chair

active/arrowhead/march 15/fof

OAH Docket No. 10-2901-12620-2
MEQB Docket No. MP-HVTL-EA-1-99

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA ENVIRONMENTAL QUALITY BOARD

In the Matter of the Exemption Application by Minnesota Power for a 345/230 kV High Voltage Transmission Line Known as the Arrowhead Project	**FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION**

This matter was heard by Administrative Law Judge Kenneth A. Nickolai beginning at 9:00 a.m. on August 28, 2000, continuing for technical hearings on August 29 through September 1, and September 5-9, 2000. Public hearings were held on August 28 and August 29, 2000, from 7:00 p.m. to approximately 10:30 p.m. Hearings were held at the Black Woods Conference Center 195 Highway 2, Proctor, Minnesota. [1] Following the close of the hearing, with agreement of all parties, the Administrative Law Judge toured the proposed route with guidance of EQB staff member, Bob Cupit. The record remained open for the submission of public comments until September 13, 2000. Initial briefs were filed on November 15, 2000 and reply briefs on December 5, 2000. The record in this matter closed for all purposes on December 5, 2000.

Appearances: Michael C. Krikava, Briggs & Morgan, 2400 IDS Center, 80 South 8th Street, Minneapolis, MN 55402, and Deborah Amberg, Senior Attorney for Minnesota Power, 30 West Superior Street, Duluth, MN 55802-2093 appeared on behalf of Minnesota Power (“Applicant”, “Company” or “MP”). Dwight Wagenius, Assistant Attorney General, 900 NCL Tower, 445 Minnesota Street, St. Paul, MN 55101-2127, appeared on behalf of the Minnesota Environmental Quality Board (“MEQB”). Bob Cupit, MEQB Staff Project Manager, 300 Centennial Building, 658 Cedar Street, St. Paul, Minnesota 55155, represented the MEQB staff. Suzanne Steinhauer, Public Advisor, 300 Centennial Building, 658 Cedar Street, St. Paul, Minnesota 55155, appeared to assist members of the public participating in this proceeding. Ginny Zeller, Assistant Attorney General, 525 Park Street, Suite 200, St. Paul, MN 55103-2106, appeared on behalf of the Minnesota Department of Commerce ("Commerce"). George Crocker, PO Box 174, Lake Elmo, MN 55042, appeared on behalf of the North American Water Office ("NAWO"). Pam McGillivray, Garvey & Stoddard, 634 West Main Street, Suite 201, Madison, WI 53703, appeared on behalf of Save Our Unique Lands ("SOUL"). Carol A. Overland, Attorney at Law, 402 Washington Street So., Northfield, MN 55057, appeared on behalf of World Organization for Landowner Freedom ("WOLF").

Notice is hereby given that pursuant to Minnesota Statutes § 14.61 and Minn. Rule 4405.0900, exceptions to this report, if any, by any party adversely affected must be filed within fourteen (14) days of the mailing date of this document. Exceptions must be filed with the Director of the Minnesota Environmental Quality Board, 658 Cedar Street, St. Paul, Minnesota 55155. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties.

The MEQB will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above or after oral argument if such is requested and granted in this matter.

Further notice is hereby given that the MEQB may accept or reject the Administrative Law Judge's Recommendation.

STATEMENT OF ISSUE

May the Minnesota Environmental Quality Board exempt the proposed Arrowhead Project from the requirements of the Minnesota Power Plant Siting Act (Minn. Stat. §§ 116C.51-.69) and, if so, should the requested exemption be granted?

Based upon all the proceedings herein, the Administrative Law Judge makes the following:

FINDINGS OF FACT

A. Procedural History

1. The Applicant, MP, is an investor-owned corporation engaged in the production, distribution, and sale of electricity. MP seeks an exemption from the requirements of the Power Plant Siting Act (Minn. Stat. Chap. 116C or PPSA) allowing it to upgrade an existing power line from the Arrowhead substation connecting to a facility at Oliver, Wisconsin. The line upgrade will only be completed if the State of Wisconsin approves construction of a 345 kV HVTL from Oliver, Wisconsin to the Weston substation.[2] Before filing this request for exemption, MP held public information meetings in Midway Township, Minnesota on May 26 and 27, 1999 on their proposal to upgrade the power line. These meetings were held at 2:00 p.m. and 7:00 p.m. in the Midway Town Hall. Notices of the meetings were published in local newspapers and mailed to landowners within 1,000 feet of the proposed right-of-way; local, state, and federal agencies; and elected governmental representatives.[3]

2. On September 16, 1999, MP submitted an application for exemption from the PPSA to the MEQB for the proposed 345/115-kV Transmission Line addition and rebuild.[4]

3. Notice of the exemption application was published in the Duluth *News-Tribune* newspaper on September 19, 1999, the Duluth *Budgeteer* on September 26, 1999, and the Proctor *Journal* on September 23, 1999. (MEQB Exhibit 2.) The notice

described the proposed project and provided that interested persons had the opportunity to comment and to request a public hearing. Similar information was included in the letters mailed to affected landowners and government officials. (MEQB Exhibit 2.) Those letters were mailed on September 21, 1999. *Id*.

4. The MEQB received nine objections to the application for exemption. On November 18, 1999, the MEQB met and ordered that a public hearing be held on the application. (MEQB Exhibit 4.) The MEQB also received over one thousand public comments responding to the public notice of MP's application.[5]

5. Notice of the public hearing in this matter scheduled for January 31, 2000 was given by publication in the Duluth *News-Tribune* on December 17, 1999 and January 23, 2000. (MEQB Exhibits 5a and 5b.) Because a motion to clarify the scope of this proceeding was certified by the Administrative Law Judge to the MEQB, that scheduled public hearing was postponed. (MEQB Exhibit 5c.)

6. The MEQB issued an Order Clarifying Scope of Hearing Record on May 3, 2000 "that the hearing be limited to impacts from the construction or operation of the project facility on human health and the environment experienced in Minnesota." (MEQB Exhibit 7, at 8.) The matter was then remanded to the Administrative Law Judge for hearing.

7. The Notice of Public Hearing was published in the Duluth *News-Tribune* on August 11, 2000. (MEQB Exhibit 5e.) The hearing schedule was also published in the *EQB Monitor* on August 21, 2000. (MEQB Exhibit 5g.) Both of these notices indicated that updated information about the hearing process would be posted on the Internet at the site maintained for this proceeding, located on the OAH website at http://www.oah.state.mn.us/cases/arrowhead/arrowhead.html. The Notice of Public Hearing was mailed to each of the persons on the MEQB's list of persons who had requested notice and to three officials of affected units of local government. (MEQB Exhibit 6b.)

B. Existing Facilities and Route

8. MP owns and operates an electric power substation, known as the Arrowhead substation, covering 22 acres[6] in Hermantown, MN.[7] The substation was first developed in 1962, was expanded in 1971 and 1977, and is now MP's second largest substation.[8]The substation has twelve power lines running from it connecting to other facilities.[9] One of those power lines is a 115 kV line, which leaves the substation in a southerly direction crossing the St. Louis River at Gary-New Duluth, Minnesota and Oliver, Wisconsin and connecting to another utility's facility in Oliver, Wisconsin.[10]

9. Three of the five 115 kV power lines exiting the substation to the south run in a common right of way corridor for 3.2 miles. These three lines are known as Lines 22, 70 and 131. Line 22 is the line located farthest west of the three lines in the 3.2 mile corridor.[11] Only Line 131continues south and east for six miles to the substation at Gary, Minnesota. Line 131 currently travels along the western edge of the

DM&IR railroad tracks, adjacent to homes in Gary[12]. From the Gary substation, a line designated as Line 132 provides the existing 115 kV connection to facilities at Oliver, Wisconsin. The route now occupied by Lines 22, 131 and 132 (except for 0.8 miles along the DM&IR rail yard) is the route proposed for the line rebuild and addition.

C. The Proposed Power Line and Route

10. MP proposes a 345/115 kV double circuit HVTL running from the Arrowhead substation for a distance of approximately 12.5 miles to the Wisconsin border at Oliver, Wisconsin.[13] The proposed transmission line (hereinafter "the Arrowhead Project") will follow existing power line right-of-way, except for eight-tenths of a mile. The width of the right-of-way will be increased by twenty feet along approximately 3.2 miles of the route. MP proposes to use double circuit, single pole structures set upon concrete foundations to support the lines. A 48-strand fiber-optic cable is proposed along the top of the new structure. The fiber-optic cable would be used for communications, including information transfer needed in transmitting electricity.[14] The initial 3.2 miles of 115 kV power line will be constructed for operation as a 230 kV HVTL (but only operated at 115 kV).[15] Six additional facility changes would need to be undertaken prior to operating that line at 230 kV.[16]

11. The Arrowhead Project, including the 345 kV HVTL connection from the Arrowhead substation to a line at Oliver, Wisconsin, includes the major following facility changes to the Arrowhead substation:

- Increase the area covered by substation equipment by 10 acres, increasing it from 22 to 32 acres. [17]
- Adding four single-phase 345/230 kilovolt transformers to interface with the 345 kV line. These transformers step up the voltage from 230 kV to 345kV. [18]
- Adding one 230 kV to 230 kV phase-shifting transformer to adjust the phase angle of electricity being transmitted on the 345 kV HVTL.[19]
- Adding control equipment, switched capacitors, 230 kV circuit breakers, and 345 kV circuit breakers.[20]

Major changes to the transmission line facilities and route from the proposed project will be described by line segment:

12. The first segment ("Midway segment") is the 3.2 mile corridor from the Arrowhead substation to Midway Township.[21] The geography of segment 1 is flat, with areas of wetlands and woods. The existing right of way currently holds three 115 kV lines. The changes proposed for this segment include:

- Dismantling the existing 115 kV line[22] on the western side of the corridor, and the H frame structures supporting it.

- Replacing that line with a double circuit, single pole, steel structure designed for 345/230 kV operation for the first 3.2 miles. The single pole, steel structures would be placed in a concrete foundation.

- Placing a 345 kV high voltage transmission line on those structures, extending from the Arrowhead substation to Oliver, Wisconsin, as part of a circuit intended to terminate at the Weston substation near Wausau, Wisconsin.

- Also placing on those structures, for 3.2 miles, a 230 kV circuit. This 230 circuit would initially be operated at 115 kV replacing the 115 kV line currently connecting to Hibbard in this segment of the corridor.

- Reconfigure the power line arrangement in the initial 3.2 mile corridor to substitute the new 230 kV circuit for the existing 115 kV line now running to Hibbard. The existing 115kV line now serving Hibbard would be used to provide service from the Arrowhead substation to the Cloquet substation.

- Widening the initial 3.2 miles of right of way by 20 feet on the westerly side of the corridor.[23]

13. Segment 2 ("Beck's Road segment") runs six miles through Midway Township, along the west end of the City of Duluth, and terminating at the City of Gary.[24] This segment begins with geography similar to the Midway segment until the right of way crosses Interstate Highway 35. At that point, the Beck's Road segment crosses a ridge and follows the base of that elevation, closely paralleling railroad tracks traveling to the southeast. The area around the right of way is wooded. Several gravel pits and a bituminous asphalt plant are located near the right of way. Major facility changes in this segment include:

- Dismantling the present Arrowhead-Gary 115 kV line identified as Line 131 and the H frame structures supporting the line.

- Replacing the structures with single pole structures with two circuits: a 345 kV line as described in segment one and a 115kV line.

- No changes are anticipated to the right of way in this six-mile segment.

14. Segment 3 ("Gary segment") travels east, beginning near Commonwealth Avenue in Gary, Minnesota, then turns south at the DM&IR Railroad tracks and follows those tracks south to the Wisconsin border. This existing line is identified as Line 132. The transmission line parallels the existing crossing of the St. Louis River into Wisconsin (the Highway 39 railroad/vehicle bridge).[25] The area along the right of way

has some residences, but is predominantly occupied by industrial uses. The Gary segment is 2.8 miles long. Major changes in this portion of the corridor include:

- Dismantling the existing 115kV identified as Line 132.
- Abandoning 0.8 mile of existing right of way.
- Establishing a new right of way for that piece of the route approximately 900 feet east of 96th Avenue West in Gary. This new portion of the right of way will be a 100-foot-wide right of way east of the DM&IR railroad tracks.
- Replacing the dismantled structures and establishing two circuits, a 345 kV circuit as described above and a 115kV circuit replacing the existing Line 132.

15. In all the segments, the 345 kV circuit will consist of two-wire bundled 1272 kcmil ACSR conductor for each of the three segments for a total of twelve. The 115 kV circuit will consist of a single 954 kcmil ACSR conductor.[26] The 230 kV segment will use a single 954 kcmil ACSR conductor, the same as that used on the 115 kV portion of the line.[27] Shield wire and optical ground wire will be utilized for lighting protection and communication.[28] The 345 kV HVTL will include new steel structures, hardware, insulators and wire. The proposed 345 kV HVTL will have a minimum clearance of 30 feet from the conductor to ground.[29] The line has a maximum achievable operating temperature of 100 degrees Centigrade (212 degrees Fahrenheit).[30]

16. The transmission lines will be supported by double-circuit single pole structures for straight, inline, and slightly-angled locations. Single poles will be composed of self-weathering steel. MP originally proposed that lines could be supported by steel lattice structures at medium-angled, heavy-angled, and dead-end locations. Lattice structures will be composed of hot-dipped galvanized steel. Both lattice and pole structures will be supported by concrete structures extending approximately twenty feet below grade. The maximum below grade depth of the footing will be forty feet, in situations where the ground provides little shear strength and fifty feet for heavily-angled structures.[31] The average height of the structure is 135 feet.[32] The tallest structure could extend to approximately 185 feet above grade.[33] Connection of the conductors to the supporting structures will be accomplished using dampers to control vibration.[34]

17. Power for the lines will be drawn from existing power flowing into the Arrowhead substation from generating facilities in North Dakota and Manitoba, Canada.[35] The existing flows enter at 230 kV, 115 kV, and 250 kV (from a DC line originating at the Square Butte substation in North Dakota).[36] These flows will be stepped up to 345 kV for transmission on the 345 kV line.

D. Exemption Standards

18. MP has applied for an exemption from the siting process under Minn. Stat. § 116C.57, subd. 5. In determining whether to grant the exemption, the MEQB must apply the following standard:

> If the board determines that the proposed high voltage transmission line will not create significant human or environmental impact, it may exempt the proposed transmission line with any appropriate conditions, but the utility shall comply with any applicable state rule and any applicable zoning, building and land use rules, regulations and ordinances of any regional, county, local and special purpose government in which the route is proposed.[37]

19. The MEQB Rule 4400.3900 governs the exemption application process. Minn. Rule 4400.3900, subp.1a requires the applicant to provide a "description of the potential human and natural environmental effects…" as identified in Minn. Rule 4400.1310.[38] The following findings address the categories of impacts listed in Minn. Rule 4400.1310, subp. 1.

E. Assessment of Impacts

Effects on Human Settlement

Displacement

20. No residential dwellings would be displaced by the proposal and there are no homes or garages located within the proposed right-of-way. The existing transmission line route has been used for approximately 20 years. In the Midway and Beck's Road segments, the route passes through sparsely populated areas. A railroad yard separates the proposed route from the residential development in Gary-New Duluth.[39] MP identified nine homes located within three hundred feet of the centerline of the right-of-way.[40] The nearest distance between a home and the centerline of the HVTL is between 160 to 180 feet.[41] The distance between several homes and the western edge of the right of way will be reduced by twenty feet in the segment running south from the Arrowhead substation for 3.2 miles (Midway segment).[42] The distance between the edge of the right of way and homes on the east side will not change. No specific distance is recommended as needed between HVTL and homes.[43] The relocation of the right of way in segment 3 will result in the power line being removed from a residential area.[44] This will result in a number of homes being farther from the line than previously.

Noise

21. Two sources of additional noise from the proposed project were identified. These sources are noise from changes to the Arrowhead substation and noise from the additional 345 kV line. MP measured existing noise levels from operation of the Arrowhead substation at several locations. Those measurements show

that noise levels at the substation property lines are currently within the MPCA noise standards.[45] Short term measurements taken show constant sound levels (L90) ranging from 35 dba to 43 dba[46] The middle level of sounds (L50) experienced at those locations ranged from 37 dba to 45 dba.[47] The high-end sounds (L10) experienced at those locations ranged from 40 dba to 48 dba.[48] The MPCA noise standards for residences are 60 dba (L50) and 65 dba (L10) in the daytime, and 50 dba (L50) and 55 dba (L10) at night.[49]

22. The phase shifting transformer to be added at the substation will emit 89 dba[50] measured at a distance of one meter. Each of the other three transformers will emit 84 dba at that distance.[51] After these additions, the calculated noise levels are 47 dba at 2000 feet from the substation and 50 dba at 1,400 feet.[52] Due to the nature of the noise generated, these noise levels are expected to be constant, that is, the noise levels will be the same at all hours of the day and night.[53] There are at least two residences within 1,200 feet of the substation.[54] The increase in noise levels is likely to exceed 10 dba at the location of the residences.[55] Unless noise is reduced by some other mechanism, the noise levels at the nearest residences are likely to exceed 50 dba at night.[56]

23. An increase of 10 db in a sound level is perceived by the human ear as being twice as loud.[57]

24. The increased levels of sound produced by the addition of the transformers for the Arrowhead project can be reduced to below 50 dba at the nearest residences through noise mitigation. Effective noise mitigation can be achieved through the use of lower noise level transformers, the installation of sound barriers, or the use of a combination of both methods.[58] Using noise mitigation technology will prevent nearby residents from perceiving a significant increase in the noise emitted from the Arrowhead substation.

25. The second source of noise is from operation of the lines. Directly under the line in periods of high humidity when the 345 kV HVTL is operated in corona, the noise level will be approximately 50-55 dba.[59] That sound becomes attenuated within approximately 100 feet and is no longer audible at that distance.[60]

Cultural Values

26. The Minnesota Historical Society State Historic Preservation Office identified no properties listed on the National or State Registers of Historical Places, nor any known or suspected archaeological properties.[61] No properties were identified as eligible for inclusion on those Registers. There are no significant cultural resources associated with the proposed route.

Aesthetics

27. The existing transmission line is supported by H frame poles[62] of approximately 65 to 75 feet in height, with an above ground height of 56.5 to 66.5 feet.[63]. For this project, MP intends to replace those poles with approximately 104

self-weathering steel structures.[64] The tallest structure would be not higher than 185 feet with a predominate structure height approximately 130 feet above ground.[65] Taller structures are required because of the proposed design of three conductors for each circuit stacked vertically.[66] The total number of poles will be reduced by replacing an H frame structure with a single pole structure.[67] At some angle locations, up to three poles may be replaced with a single, taller pole. The footprint of the single-pole structure is smaller than the footprint of the combined perimeter of the two or three-pole structures.[68]

Recreation

28. Two of the three segments of the route, the Beck's Road segment and the Gary segment, contain recreational areas near the right of way. Magney Park, Short Line Park, Merritt Park, and portions of the Willard Munger Trail are within relatively short distances of the Beck's Road segment and portions of the Gary segment. The Buffalo House Campground is within a half-mile south of the Beck's Road segment. Fond du Lac State Park is located within one mile of the Beck's Road segment at the nearest point to the park boundary.[69] Both the Willard Munger Trail and the Western Waterfront Trail intersect the existing power line right of way.[70] The proposed HVTL runs along the existing power line right of way.

29. Short Line Park lies between two sets of railroad tracks along a sloping elevation below Elys Peak.[71] There is no direct road access, provision for automobile parking, or facilities in Short Line Park for recreation.[72] Short Line Park is occasionally used by rock climbers.[73] The existing 115 kV power line abuts the western end of Short Line Park.

30. Merritt Park lies directly south of Short Line Park, south of Beck's Road and the existing 115 kV power line right of way.[74] At its nearest point, the power line right of way is within 1,000 feet of Merritt Park.[75] There is road access to Merritt Park, from Beck's Road, but no facilities are located there for recreation activities. A demolition landfill is located adjacent to Merritt Park.[76]

31. Magney Park is located atop the ridge overlooking the Gary segment and much of the Beck's Road segment.[77] A portion of the Willard Munger Trail runs through Magney Park. Direct road access is provided to Magney Park by Skyline Parkway. There are no facilities in Magney Park for recreation.[78]

32. The Willard Munger Trail and Western Waterfront Trail are recreational trails. The Willard Munger Trail is constructed along an abandoned railroad right of way.[79] It runs parallel to the power line right of way for approximately 1,000 feet with a distance of 300 to 400 feet separating the two.[80] The two intersect at one point. The Willard Munger Trail is a popular recreational resource. The 345 kV HVTL will not be significantly more visible to users of the Willard Munger Trail than the existing 115 kV power line that currently occupies the right of way.

33. The Western Waterfront Trail runs along a railroad right of way located along the St. Louis River.[81] The City of Gary, radio towers, extensive railroad facilities, and a steel casting plant are all visible to the landward side of the Western Waterfront Trail.[82] The existing 115 kV power line is visible from all points of the Western Waterfront Trail.[83]

34. The Buffalo House Campground is south of the Beck's Road segment of the proposed right of way. The Campground is located within a half-mile of the right of way, where the right of way crosses Interstate 35.[84] A restaurant is located at the entrance to the Campground.

35. The Fond du Lac State Park is located approximately one mile south of the 115 kV power line right of way at its nearest point.[85] The topography between the right of way and the State Park precludes park visitors from seeing the Arrowhead HVTL.[86]

36. There are no long-term impacts on public recreation arising out of the Arrowhead Project. There may be temporary interruptions to some recreational uses during the construction period.[87]

Public Services

37. MP will notify the DM&IR railroad when installation of the 345 kV HVTL and 115 kV power line will be affecting the railroad's trackage. Similar notification to the Minnesota Department of Transportation will occur when the construction crosses Interstate 35. MP will schedule its construction activities to minimize the affect on vehicular traffic.[88] There are no impacts on public services arising out of the Arrowhead Project.

Public Health and Safety

38. Electric and magnetic fields (EMF) arise from the flow of electricity and the voltage of a line. The intensity of the electric field is related to the voltage of the line and the intensity of the magnetic field is related to the current flow through the conductors.[89] There are no state or federal standards for transmission line electric fields. The MEQB has included permit conditions for other transmission lines specifying that maximum electric fields must not exceed 8 kV/meter.[90] The maximum anticipated electric field exposure, measured directly under the HVTL is approximately 6.5 kV/meter.[91] Within 100 feet of the centerline of the HVTL, the electric field strength nears zero. [92]

39. EMF is also measured in milligauss (mG). Common electrical appliances produce EMF fields while in operation, as do HVTLs. The Arrowhead Project will increase EMF exposures for persons living along the right of way above current EMF levels.[93] The amount of the increase is small, ranging from approximately 50 mG at the edge of the right of way to approximately 10 mG at the distance of the nearest home to the Arrowhead HVTL.[94] These increased levels occur at the periods of peak flow and are present approximately 5% of the time.[95]

40. The record of this matter contains an evaluation of research and investigations conducted into the effects of HVTL, including "electric fields resulting from such facilities on public health and welfare, vegetation, animals, materials and aesthetic values."[96] Research into human health impacts from electric fields, issued by the National Institute of Environmental Health Sciences shows "weak scientific evidence that exposure may cause a leukemia hazard. In our opinion, this finding is insufficient to warrant aggressive regulatory concern."[97]

41. The "Henshaw Hypothesis" asserts that aerosols are affected by the electromagnetic fields surrounding HVTL, resulting in the deposition of particulate matter under and around power lines, resulting in adverse health effects.[98] The research conducted into the Henshaw Hypothesis does not support a conclusion that adverse environmental effects or health effects arise from the presence of aerosols or deposition of particulate matter in the area of HVTLs.[99]

42. Electric currents in the earth can be caused by transmission of electricity where grounding is used to complete the electric circuit.[100] In one of the two design options under consideration, the Arrowhead HVTL will use grounding only in one location for every distinct segment of HVTL (approximately one to two miles apart).[101] The other design option uses grounding at only one end of the line. Both arrangements prevent completion of an electric circuit in the earth between the segments.[102] There is no evidence of adverse health effects arising from such currents.[103]

Land-Based Economies

43. An aggregate quarry (gravel pit) operates adjacent to the Beck's Road segment. There is no indication that current or future operations of the quarry will be affected by the Arrowhead HVTL. Since the Arrowhead HVTL will be using existing right of way currently occupied by a 115 kV power line, the impact on land values from the proposed 345 kV HVTL will not be significant. With the increase of the width of the Midway segment of the right of way some additional agricultural land will be affected, but the effect is not significant. No significant effects on land-based economies have been identified arising out of the Arrowhead Project.

Archaeological and Historic Resources

44. No archaeological or historic resources have been identified along the route of the Arrowhead Project HVTL. No significant effects on archaeological or historic resources have been identified arising out of the Arrowhead Project.

Natural Environment

45. Ten acres of cleared, undeveloped ground will be occupied by equipment when the Arrowhead project is constructed. A twenty-foot-wide area. 3.2 miles in length will be cleared in order to widen the existing right of way. No environmental resources have been identified that would be affected by this clearing. Use of the existing right of way reduces the potential long-term impact to a minimum. MP has indicated that, where the line crosses wetlands, construction will occur in winter, when the ground is

frozen. Where wetlands are not sufficiently frozen, mats will be used to minimize damage to plant life present.[104] No significant adverse effects on the natural environment have been identified from the operation of the Arrowhead HVTL.

Rare and Unique Natural Resources

46. The Natural Heritage and Non-game Research Program of the Minnesota Department of Natural Resources (DNR-NHNRP) conducted a review of its records to assess the potential impact of the Arrowhead Project on rare or unique plant or animal species. DNR-NHNRP indicated that seven known instances of such plants and animals exist in the area, but not within 1,000 feet of the HVTL right of way.[105] These instances are four observations of lake sturgeon, two observations of moschatel (a flowering plant) and one observation of Carolina spring-beauty (a flowering plant).[106] The distance between the instances of these species and the HVTL right of way is sufficient to prevent adverse impact on those species. The Arrowhead Project is not expected to adversely impact any rare or unique plant or animal species.

Application of Design Options

47. MP has opted for single-pole construction for the Arrowhead HVTL to minimize the right of way required. A portion of the existing Arrowhead-Cloquet 115 kV power line (Line 22) will be reconstructed to enable it to carry a 230 kV load. This reconstruction precludes the need to undertake an additional approval proceeding in the event that this load is needed to meet anticipated future demand for electricity. MP has examined design options to optimize the efficiency and minimize the impact of the Arrowhead HVTL.

Existing Rights-of-way

48. The siting considerations for transmission lines favor the use of existing rights-of-way to minimize the impact of those lines on the areas they traverse. The Arrowhead Project uses the existing corridor for right of way. In the Midway segment, that right of way must be widened by twenty feet over a 3.2 mile distance. The land affected is primarily agricultural. The expansion of the existing right of way for that segment has no significant impact.

49. The other alteration to the right of way for the Arrowhead Project moves the 0.8 miles of the existing route to the eastern side of the DM&IR rail yard. The change is proposed at the request of the landowner, the DM&IR railroad. The movement of the 0.8 mile length of right of way does not result in significant human or environmental impact. Removing the existing 0.8 mile segment of 115 kV power line from its existing location is a benefit to persons living in the eastern portion of Gary. The Arrowhead Project uses existing rights-of-way to minimize the impact of upgrading the existing 115 kV power line to a 345 kV HVTL.

Electrical System Reliability

50. The Arrowhead Project will improve the electrical system reliability for consumers in both Minnesota and Wisconsin. The existing system of distribution has only one major source of electricity for western Wisconsin from Minnesota, the 345 kV King-Eau Claire-Arpin HVTL (K-EC-A HVTL). The K-EC-A HVTL experienced a significant failure on June 25, 1998 that adversely affected electricity consumers in both Wisconsin and Minnesota. Other situations have arisen over past few years that could have resulted in failures similar to that on June 25, 1998. Adding a second 345 kV connection to the Wisconsin transmission and distribution systems will reduce the likelihood of such failures and improve the reliability of the electrical system for both Minnesota and Wisconsin consumers.

Design and Route Dependent HTVL Costs

51. There have been no costs identified for constructing, operating, and maintaining the Arrowhead Project HVTL which are dependent on design and route.

Unavoidable Adverse Human and Natural Environmental Effects

52. There have been no significant adverse human, natural and environmental effects from the Arrowhead Project identified either at the Arrowhead substation or along the HVTL route that are unavoidable consequences of the construction of the Arrowhead project or operation of the 345 kV HVTL that will be installed.

Mitigation of Adverse Environmental Effects

53. The proposed construction of the Arrowhead HVTL incorporates several features to minimize potential adverse environmental effects[107] associated with the construction and operation of the Project.

- Right of way clearing will be limited to vegetation actually affecting the safe operation of the HVTL. MEQB Ex. 1, at 11. The only new right of way clearing would occur along the 3.2 mile length of the Midway segment and the 0.8 mile length of the Gary segment with relocated right of way.

- All construction debris will be removed from the right of way. Grass and low-growing vegetation will be "encouraged" to provide revegetation of construction areas. MEQB Ex. 1, at 11. Silt will be prevented from entering surface waters by installation of barriers and use of set back zones, where appropriate.

- Special consideration will be given where the right of way crosses stream banks to ensure that erosion will be minimized and existing shade retained to prevent changes in water temperature. MEQB Ex. 1, at 17. No in-stream work will be performed between September 15

and April 30 to protect the four designated trout streams being crossed by the right of way. *Id*.

- The potential for damaging vegetation during installation will be minimized by constructing the structures for carrying the HVTL during the winter months, when the wetlands areas are frozen. When weather conditions have resulted in insufficiently frozen ground, mats will be used to prevent damage.

- Structures crossing open fields will be placed so as to minimize maneuvering for farmers during haying.[108]

Cumulative Present and Future Demands of the Project on Air and Water Resources

54. The Arrowhead Project will not impose demands on air or water resources.

Based on the foregoing Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. Any of the foregoing Findings more properly designated as Conclusions are hereby adopted as such.

2. The Administrative Law Judge and the Minnesota Environmental Quality Board have jurisdiction over the subject matter of the hearing pursuant to Minn. Stat. §§ 14.50 and 116C.06.

3. All relevant substantive and procedural requirements of law and rule have been fulfilled prerequisite to an application for exemption from the Power Plant Siting Act.

4. The proposed project "will not create significant human or environmental impact" in any of the categories of impact examined under the terms of Minn. Rule 4400.3310, except the noise impact noted at Finding 22. This impact can be eliminated by utilizing the mitigation methods noted at Finding 24.

5. The Applicant has demonstrated that the Arrowhead Project meets the standards for exemption from the Minnesota Power Plant Siting Act process in Minn. Stat. § 116.57, subd. 5.

Based upon the foregoing Conclusions, of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

That the MEQB grant the Applicant's Application for exemption from the requirements of the Minnesota Power Plant Siting Act (Minn. Stat. §§ 116C.51-.69) for

the construction of the 345 kV/115 kV and 345/230 kV High Voltage Transmission Line (for one segment operated at 115 kV), and modifications to the Arrowhead substation, known as the Arrowhead Project, subject to the condition that noise impacts be reduced at the Arrowhead substation, and necessary permits be obtained from the federal and state agencies and local units of government with appropriate jurisdiction.

Dated this _29th_ day of January, 2001

/s/ Kenneth A. Nickolai_____
KENNETH A. NICKOLAI
Administrative Law Judge

Reported: Karen J. Macaulay, Citran, Duluth, Minnesota
Transcript prepared, Twelve Volumes.

NOTICE

Under Minn. Stat. § 14.62, subd. 1, the agency is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.

MEMORANDUM

Burden of Proof

The parties dispute the burden of proof. By applying for an application for exemption from the PPSA, MP has the burden to demonstrate that the exemption should be granted. MP's burden is to present credible evidence that the proposal will not "have a significant impact……" MP argues that the burden is on the opponents to the application to demonstrate that a significant impact exists. In advancing this argument, MP relies on decisions made in cases arising under the Minnesota Environmental Rights Act[109]. In ***PEER*** the Supreme Court explained that under *that* act, "in order to make "a prima facie showing" the plaintiff must prove the existence of a "(1) protectible natural resource, and (2) pollution, impairment or destruction of that resource."[110] However, this case is not a citizen-initiated action under MERA, but a utility initiated request that a project be exempted from the Power Plant Siting Act.

The Administrative Law Judge concludes that MP met its burden of presenting credible evidence that the proposal would not have a "significant human or environmental impact…." The ALJ also concludes that the opponents did not counter MP's evidence and establish the likelihood of significant human or environmental impact. As will be discussed later in this memo, there is evidence that this project will or may have an impact on humans or the environment. However, the ALJ was not convinced that the potential impacts met the legal test for significance.

NAWO maintains that the applicant for an exemption must prove there are no significant impacts "beyond a reasonable doubt." NAWO Brief, at 2. The law does not impose that high an evidentiary standard to this administrative proceeding.[111] Minn. Rules 1405.1700, Subp. 7 provides, "Any route or site proposer must prove the facts at issue by a preponderance of the evidence…".

Regardless of the burden of proof, NAWO correctly points out that Minn. Stat. § 116C.57, subd. 5, states that the MEQB "may" exempt a proposed transmission line from the certificate of need process. The statute then gives the MEQB discretion to grant or deny an exemption. The final agency decision will be made by the MEQB using the following standard:

> If the board determines that the proposed HVTL will not have a significant human or environmental impact, the board may exempt from the act with any appropriate conditions the construction of the proposed facility within the proposed route.[112]

Significant Human or Environmental Impact

Almost every action has some impact on humans or on the environment. The issue in this case is whether the identified impacts rise to the level of being "significant" under the law. NAWO, WOLF, and SOUL assert that MP failed to demonstrate that no significant human or environmental impact will occur based on the application of the "precautionary principle." SOUL described the precautionary principle as follows:

> 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.[113]

MP objected to using the precautionary principle as requiring proof of "negative facts."[114] To use the precautionary principle would, in MP's opinion, replace the existing standard with "unsubstantiated or speculative impacts."[115]

Minnesota law does not recognize the precautionary principle as the standard for determining a “significant impact.”[116] The term "significant" is an important limitation in law. The ALJ concludes that it requires a showing that a potential impact is serious and material. It further is not merely incidental and cannot be readily mitigated.[117] In this case, which is to determine whether or not the MEQB should allow the exemption sought by MP, the determination of significance must be made by looking to the difference between the operation of the existing power line and the upgraded line proposed.[118]

Health Effects

WOLF, SOUL, and NAWO assert that MP failed to demonstrate that the Arrowhead Project will not create significant human or environmental impact because MP has not proven that 345 kV HVTL has no effect on human health. WOLF noted the conclusion of NIEHS that:

> The NIEHS concludes that ELF-EMF exposure cannot be recognized as entirely safe because of weak scientific evidence that exposure may cause a leukemia hazard. [119]

WOLF also relied upon the NIEHS conclusion that "[ELF-EMF is a] possible human carcinogen."[120]

WOLF asserts that MP has failed to account for the higher exposure to magnetic fields that persons living along the Arrowhead Project route will experience due to the increase in voltage from the existing 115 kV power line to the 345 kV HVTL. Based on measurements made at a 345 kV HVTL between northern Wisconsin and Michigan's Upper Peninsula,[121] the ambient EMF levels are 30 mG within one hundred feet of the right of way centerline to one side and 80 mG within one hundred feet of the centerline on the other side.[122] The difference is due to the 345 kV HVTL being located off-center in the right of way. There are higher estimates of increased EMF levels of 60 mG and 100 mG at 100 feet from each side of the right of way centerline when the 345 kV HVTL is operated at peak capacity.

In the case of the Arrowhead HVTL, the nearest homes are within 300 feet of the route.[123] But the intensity of a magnetic field drops exponentially with distance.[124] MP calculates that, during peak periods, the maximum exposure of persons in the closest residence is 10 mG.[125] WOLF, SOUL, and NAWO have not shown that persons in the homes nearest to the Arrowhead HVTL will be experiencing EMF levels in excess the average exposure that is normally experienced by any user of electricity and common household appliances. From the distances between the nearest homes and the Arrowhead HVTL, those residents will not experience significantly higher (and perhaps not even measurably higher) EMF levels. The average daily exposures of persons studied in EMF-RAPID ranged from 28% of persons exceeding 10 mG (milligauss), 11% exceeding 20 mG, and 2% exceeding 50 mG.[126] The in-home averages were 8 mG while awake and 5 mG while sleeping.[127]

The EMF-RAPID study arrived at a conclusion regarding the risks posed by EMF and what precautionary action should be taken. That conclusion states:

> The NIEHS concludes that ELF-EMF exposure cannot be recognized as entirely safe because of weak scientific evidence that exposure may pose a leukemia hazard. In our opinion, this finding is insufficient to warrant aggressive regulatory concern. However, because virtually everyone in the United States uses electricity and therefore is routinely exposed to ELF-EMF, passive regulatory action is warranted such as a continued emphasis on educating both the public and the regulated community on means aimed at reducing exposures. The NIEHS does not believe that other cancers or non-cancer health outcomes provide sufficient evidence of a risk to currently warrant concern.[128]

The EMF-RAPID description of ELF-EMF as a "possible human carcinogen" does not demonstrate that HVTL constitutes a substantial human impact.[129]

NAWO, SOUL, and WOLF also asserted that MP failed to account for the impact of ground current on human health. The transmission of electricity along HVTLs can

create a return current through the ground. This phenomenon, known as ground current, passes electricity back along the ground under the line to complete the electric circuit.[130] MP responded that there has never been any showing of adverse health impacts from ground currents arising from HVTLs and that no studies have been performed to show any such impact.[131]

Evidence of the impact caused by "stray voltage" on humans and livestock was introduced to support a claim of substantial impact caused by the Arrowhead Project.[132] Stray voltage is caused by the grounding of the distribution system to individual consumers. The Arrowhead substation and Arrowhead HVTL are designed without the sort of grounding that can result in stray voltage.

There is no evidence in the record from which to draw a conclusion that ground currents have general impacts on human health or the environment. Stray voltage will not be caused by the Arrowhead Project. There has been no showing in this matter of an adverse human health impact that would trigger a full-scale routing review under the PPSA.

Noise

MP asserted that no significant increase in noise will arise from the proposed line or modifications to the Arrowhead substation. The mitigation originally proposed in MP's application for exemption was withdrawn, due to the asserted lack of additional noise. MP cites the measurements conducted of the noise levels around the Arrowhead Substation and conclusions drawn from a study conducted to support this assertion and modification of the application.[133]

The study relied upon by MP was designed and assessed by Dr. Hooshang Khosrovani of Veneklasen Associates. An employee of MP performed the measurements using equipment calibrated and provided by Veneklasen Associates. Dr. Khosrovani “performed noise calculations and analysis for estimating the expected noise levels around the Arrowhead substation due to the operation of transformers and impact of proposed additions.”[134] MP asserts that "the results of the noise tests showed that in all instances, applicable Minnesota noise standards will not be exceeded."[135] MP maintains that any increase in noise caused by the upgrade will be "below the human ear’s ability to perceive any meaningful difference."[136] MP also relies upon the presence of roadways and truck traffic near the substation in concluding there will be no substantial impact on nearby residents due to noise.[137] MP also cites the MPCA noise standards as support for its proposal to modify the Arrowhead substation without conducting any mitigation.

The MPCA has set out "rules of thumb" to assess the impact of sound.[138] An increase of 3 dB reaches the level of human perception.[139] An increase of 5 dB is described as "quite noticeable."[140] When sound increases by 10 dB, the sound is perceived as "twice as loud."[141] The Veneklasen study assessed sound levels as perceived by persons at existing homes near the Arrowhead substation operating with existing equipment. The study used instruments to quantitatively measure the sounds near the Arrowhead substation. In addition to the quantitative measurements, subjective assessment of impact by ear of existing facilities was noted by the person conducting the testing and shows audible noise as "slightly, "noticeable," "somewhat

loud," "very noticeable," and "loud, but not obvious."[142] The measurements for some of the noise impacts at adjacent homes were conducted when the DC converter station was out of service.[143]

MP is adding four transformers, using one as a back-up to the three that will be in operation. The calculated noise level that would occur with the addition of the transformers was based upon the measurement of existing equipment. The single transformers would emit 84 dBA at a distance of one meter. The phase shifting transformer emits 89 dBA at that distance.[144] The EEI Electric Power Plant Environmental Noise Guide methodology was used to determine the potential impact of the new equipment on adjacent residents. Using the EEI methodology, the conclusion derived in MP's study stated:

> The results of these calculations indicate a noise level of approximately 47 dBA, due only to transformer contributions, may be expected at a distance of 2000 feet away. Any location at a distance of less than 2000 feet will have a higher level of transformer noise impact.[145]

Due to the anticipated contribution to the noise impact by the new equipment, the report commissioned by MP recommended that noise reduction be accomplished by requiring that the three 300 MVA transformers being added as a result of the Arrowhead Project be specified at "noise levels of 12 dBA below NEMA ratings for these transformers (NEMA-12) in the procurement specifications."[146]

The evidence is that noise from this equipment will be both perceptible and annoying.[147] MP pointed out that the existing noise was within the MPCA standards for residential areas. MP asserted that the resulting noise from the Arrowhead Project upgrade would fall within that limit and therefore no mitigation of noise impacts is required. MP claimed that there would be no perceptible increase in sound at the property line of the Arrowhead substation caused by the new equipment.[148] That assertion is contradicted by the report and is not supported by facts in the record. The author of the study was unaware of the distance between the Arrowhead substation and the location of either the monitoring equipment or the adjacent homes.[149] The nearest houses to the Arrowhead substation are well within 2000 feet.[150] MP cannot rely upon a calculation of a noise impact on a location beyond the actual person hearing the sound to establish that there will be no substantial impact on that person.

MP also relies upon the MPCA standards as establishing the standard to be met in obtaining the exemption in this proceeding without conducting mitigation. The appropriate test for obtaining an exemption is not whether the MPCA noise limit is met. Rather, the test is whether a substantial impact will be caused by the new equipment. MP has failed to meet its burden to demonstrate that there will be no substantial impact on nearby residents without the inclusion of some noise mitigation at the Arrowhead substation. This noise mitigation can be accomplished by purchasing transformers that emit less noise. Noise mitigation may be accomplished by installing sound barriers that will reduce the overall noise impact of the Arrowhead substation. The reduction methods will reduce the noise created by the project to eliminate any substantial impact.

Land Valuation

WOLF asserts that MP's failure to prepare appraisals results in a failure of proof that the Arrowhead Project will not have significant impact on land values. WOLF, however, relies on the eminent domain provision of the PPSA as the basis for this claim. This proceeding is to determine if the Arrowhead Project is to be exempted from the requirements of the PPSA. The standards to be met in applying for an exemption are clearly set out. Impact on land valuation is not, by itself, a consideration in determining whether an exemption is appropriate. Land valuation can be included to the extent that it affects other listed considerations. In this matter, there is no evidence that market values will be measurably affected by replacing a 115 kV power line with a 345 kV HVTL. The homes that were part of the market survey conducted by MP were on the market for an average of 110 days, which is above the market average. There is no evidence that size of the power line will further increase that average. There is no evidence that market values for land, even if altered, will affect human settlement or land economies.

Mining Operations

An aggregate quarry and an asphalt facility are located on the Beck's Road segment.[151] MP maintains that the Arrowhead HVTL will not impair the functioning of either operation.[152] WOLF maintains that MP used the wrong standard in assessing the impact on mining operations. According to WOLF, the potential impact of particulate matter interacting with the corona of the HVTL is key. That potential impact was addressed as a consideration regarding health affects and it was determined to not have the potential for significant impact.[153] There is no evidence of substantial impact on land-based economies arising from the location of the Arrowhead HVTL.

Eminent Domain

MP intends to seek additional easements to widen the right of way in the initial 3.2 miles of the corridor. MP has indicated that it will seek to negotiate with landowners for easements. But MP will use eminent domain to obtain those easements if mutually agreeable terms cannot be reached. WOLF asserts that only if the full routing provisions of the PPSA are applied will landowners have their property interests protected. Further, WOLF asserts that eminent domain is only available to MP if the Arrowhead Project has been subjected to the Certificate of Need process and the demonstration of need made. In this matter, only the impacts on human settlement that result in significant human impact are to be considered. There has been no showing that the potential application of eminent domain will result in such impact. WOLF's assertion that eminent domain is not available without a finding of need cannot be addressed in this proceeding. That dispute is properly brought before the District Court in the event that such a proceeding arises.

Historic Resources

A bridge (Historic Bridge No. L-6007, hereinafter "Stewart Creek Bridge") on Skyline Parkway is identified by WOLF as a historic resource affected by the Arrowhead HVTL.[154] The Oliver Bridge over the St. Louis River is also identified as a "unique bridge." These resources are cited as being substantially affected by the Arrowhead HVTL. The automobile traffic over the Oliver Bridge passes on the deck beneath railroad tracks. Visibility is significantly impaired from the automobile level of the Oliver

Bridge.[155] The current power line at the Oliver Bridge crossing is visible from the approaches. REL-8. No one has described any meaningful aesthetic difference affecting these resources between seeing the proposed single pole structures and seeing the existing H-pole structures.

WOLF maintains that the Arrowhead HVTL affects the Stewart Creek Bridge on Skyline Parkway. There is no testimony in the record of where that bridge is in relation to the proposed Arrowhead HVTL. There is no testimony to support a finding that the proposed HVTL will be visible from that bridge. Based on a topological map of the area, the Stewart Creek Bridge is located approximately 1.5 miles from the nearest point along the Arrowhead HVTL route.[156] The topography surrounding that location strongly suggests that the Arrowhead HVTL will not be visible from the Stewart Creek Bridge.[157] The record is insufficient to demonstrate that the Arrowhead Project will have a significant impact on historic resources.

Recreational Resources

The impact on recreational resources caused by the Arrowhead HVTL is limited to the change in visibility of the power line. In some areas, the switch to a single pole design will reduce the intrusiveness of the power line because of its smaller footprint. The much taller poles will, however, be more visible from viewpoints at several recreational areas. The parties differed on how much impact this additional visibility would have on people using the recreational resources in the vicinity of the Arrowhead HVTL.

One example of an affected viewshed is the overlook portion of Skyline Drive. From this vantage point, one can observe much of the Beck's Road segment and the entirety of the Gary segment.[158] The Skyline Drive area overlooking the Arrowhead route is both passable by automobile and frequently used.[159] The views from Short Line Park and the western end of Magney Park are substantially similar to that of the Skyline Drive overlook. The viewshed of the easternmost end of Magney Park contains all of the Gary segment and St. Louis River running north to the waterfront area of the City of Duluth.

WOLF demonstrated that the Arrowhead HVTL will be visible from the road access point to the Willard Munger Trail.[160] No evidence was introduced to support a finding of substantial impact from the Willard Munger Trail itself since the difference is the height and footprint of the pole, not its existence. Similar problems exist with the claims of substantial impact from the scenic views overlooking the Beck's Road and Gary segments. The views afforded to individuals from these points are not just of a power line, but also of an area dedicated to industrial uses. Railway lines, rail yards, a 115 kV power line, an electrical substation, quarries, factories, and docks are all visible from the vantage points above the proposed Arrowhead HVTL. The ALJ concludes that the overall visual impact of the proposed Arrowhead HVTL will be indistinguishable from the existing uses along the route.

Electrical System Reliability

Reliability is defined by NERC as adequacy and security.[161] Adequacy is the ability of the electrical system to supply the demands of customers, including during

periods of outages. Security refers to the ability of the system to withstand disturbances through short circuits (tripping) or unanticipated loss of generation or transmission capacity. There is no meaningful difference between system loading that occurs due to consumer demand and system loading occurring due to environmental disruption. A failure on one portion of the electrical transmission grid can cause power disruptions in other areas. A primary reason cited by MP for upgrading the existing 115 kV power line to a 345 kV HVTL is to improve the reliability of the existing electrical transmission system. The Department of Commerce indicated that the existing connection between the Mid-Continent Area Power Pool (MAPP) and the Mid-American Interconnected Network (MAIN) is supported only by the K-EC-A 345 kV HVTL and this sole connection has resulted in reliability problems.

A disturbance in the regular transmission of electricity between MAPP and MAIN occurred on June 10-11, 1997 (hereinafter "the 1997 disturbance").[162] On June 10, 1997 the K-EC-A line was operating at 945 MW (which would ordinarily result in action being taken), but the load dropped to 850 MW, so no relief was requested. Shortly thereafter, the southern interconnection (known as "SPP") with MAIN showed signs of overloading. Shortly after midnight, the K-EC-A line tripped and the resulting power flows were far over the SPP's operating limits for its lines. The overload condition existed until approximately 1:30 a.m. on June 11, 1997.[163] The conclusion reached after the 1997 disturbance was that a significant risk of a regional blackout existed and such a blackout had been narrowly averted.[164]

The K-EC-A HVTL failed on June 25, 1998 (”1998 service interruption"). The 1998 service interruption occurred during a thunderstorm that tripped both the Prairie Island-Byron 345 kV HVTL and the K-EC-A HVTL. "Cascade tripping" then ensued, causing more than 60 transmission lines (ranging from 345 kV to 69 kV) to fail. The resulting disruption of power delivery adversely affected electricity consumers in both Wisconsin and Minnesota. A significant risk of electrical blackout throughout Minnesota was avoided only when some of the lower voltage lines automatically reclosed and held.

Another disturbance in the regular transmission of electricity between MAPP and MAIN occurred on June 10, 1999 (hereinafter "the 1999 disturbance").[165] The 1999 disturbance was the result of system loading on the K-EC-A line. The system was considered to be "insecure" for several hours. An additional element of risk to the delivery of electricity was posed at that time due to the presence of thunderstorms in the area.

The 1998 service interruption and the system disturbances in 1997 and 1999 were cited by both MP and Commerce as demonstrating the need for an additional 345 kV connection between MAPP and MAIN. MP maintains that the proposed Arrowhead project will improve the performance of the electrical grid between Minnesota and Wisconsin. On the other hand, WOLF asserted that:

> The transmission crisis is a crisis of the utilities' making through their "increased market transactions" in their desire to move all the power they can sell, overloading lines for bulk transfer and putting local loads and the grid in jeopardy.[166]

With these arguments, NAWO, SOUL, and WOLF argue that the purchase and sale of bulk power should be examined separately from the existing transmission system. Under this approach, increases in market demand would not be included in the assessment of system security. Thus, a project proposed to meet market demands on a system would not qualify as being needed to improve system security. The ALJ concludes this is not the correct standard since either demand or an incident can affect system reliability and security.

NAWO also asserts that the Arrowhead project is dependent upon all of the associated projects being completed [167] and it is no longer necessary. NAWO quotes the WRAO[168] Executive Summary:

> In order to achieve the benefits which construction of plan 3j would provide, it must be constructed in its entirety. For all the plans presented, several significant additions of 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.[169]

NAWO urges that "administrative notice" be taken that Brief the Chisago-Apple River 230 kV project has been withdrawn.[170] The activity listed as "associated projects and upgrades" in the WIRES[171] Phase II Report for Plan 3j does not include the Chisago-Apple River 230 kV project.[172] The language cited by NAWO from the Executive Summary describes the withdrawn Chisago-Apple River project as "an integral system reinforcement and is also critical for local load serving." This language, without more, does not support a conclusion that the absence of the Chisago-Apple River 230 kV project will eliminate the benefits of the Arrowhead project.

MP has demonstrated that the Arrowhead project will result in improvements in adequacy and security and benefit electric consumers in both MAPP (including Minnesota) and MAIN.

Relationship to Other Projects

NAWO, SOUL, and WOLF maintain that MP cannot obtain an exemption in this matter because the Arrowhead Project is part of a connected action or phased upgrade of other facilities to provide the electricity that will be transmitted to Wisconsin, and that, when taken together, these actions will require a Certificate of Need from the Minnesota Public Utilities Commission.

Minn. Rule 4410.0200, subd. 9b defines "connected actions" and subd. 60 defines "phased action." Both of these rules set out the standards for determining if different projects must be combined to determine the appropriate scope of review. NAWO, SOUL, and WOLF asserted that an exemption to the PPSA process cannot be granted since the Arrowhead Project cannot be completed without also completing

associated projects that would trigger the Certificate of Need review process.[173] These associated projects are asserted to be the Hilltop upgrade, modifications to the Forbes HVTL, and the Blackberry HVTL. There is no evidence indicating that any upgrades to the Forbes HVTL or the Blackberry HVTL are being undertaken by MP.

A portion of the Arrowhead Project upgrades a 3.2 mile portion of the existing 115 kV power line (Line 22) to the capacity for operation at 230 kV. MP intends to continue operating Line 22, now running from the Arrowhead substation to the Cloquet substation, at 115 kV. Additional upgrades are required before MP will be able to operate Line 22 at 230 kV and reconfigure the connection to transmit electricity to the Hilltop substation.[174].

No time frame has been established for performing the additional upgrades to Line 22 and the eastern portion of Line 70 to operate that line at 230 kV.

NAWO, SOUL, and WOLF maintain that the upgrade of Line 22 demonstrates that the Arrowhead Project is a phased upgrade, and thus the distance between the Arrowhead and Hilltop substations must be added to the length of the HVTL. Minn. Rule 4400.1310, subp. 1.G., requires that utilities include planning for additional upgrades along existing rights of way whenever a project is planned. Excluding projects for complying with the rule for prior planning is not consistent with the statutorily-authorized exemption process. There is no evidence to establish that a timetable exists to complete a 230 kV HVTL between the Arrowhead and Hilltop substations.

In the course of planning the Arrowhead Project, the potential for finishing a 230 kV HVTL between the Arrowhead and Hilltop substations became apparent.[175] The need for a 230 kV HVTL is not anticipated in the Hilltop substation service area before 2005 to 2010.[176] This does not constitute either a phased action or connected action.

The Arrowhead Project is essentially identified in the WIRES Study as the Minnesota portion of Plan 3j. Plan 3j has a number of "associated projects and upgrades" identified as needed to complete Plan 3j. The activity listed as "associated projects and upgrades" in the WIRES Phase II Report all occurs in Wisconsin.[177] These "associated projects and upgrades" are not part of the Arrowhead Project and do not constitute phased or connected actions.

The only changes required to substations other than Arrowhead and Gary are upgrading software to accommodate the relaying needs of the altered system.[178] These changes do not preclude MP from obtaining an exemption from the PPSA on that basis.

Environmental Effects from Coal-fired Generation

NAWO and the National Wildlife Federation (NWF) introduced substantial evidence that coal-fired electricity generation (such as that conducted in North Dakota) causes pollutants, including mercury, to be emitted into the atmosphere.[179] Once in the atmosphere, mercury is deposited into bodies of water, where it collects.[180] Once in these bodies of water, mercury is absorbed by fish and from there to aquatic animals and humans.[181] Mercury contamination poses both an adverse environmental effect and an adverse public health impact.[182]

MP maintained that the Arrowhead Project would result in the reduction of mercury emissions from existing coal-fired generating plants.[183] This estimate was based on computer-modeling performed by a consultant indicating that completion of the Arrowhead project would reduce line losses.[184] SOUL introduced an assessment of the computer-modeling performed that identified limitations of with this analysis.[185] A number of the concerns were conceptual in nature, addressing the potential for long-term changes in the electricity generation mix that might result from the Arrowhead Project.[186]

One specific concern raised by SOUL was the critical dependence on the data used to generate its model.[187] Under cross-examination, MP's witness on the computer model was unable to respond to questions regarding the specific data relied upon for the computer model.[188] Some of the data initially provided by MP had been incorrectly used.[189] Some of the data used in the modeling appears to have been of the "best guess" variety.[190] The data run of the information was not retained or produced to support the conclusions reached.[191] If the data input into the model cannot be verified, the model's conclusions cannot be relied upon.[192]

The reduction in mercury asserted by MP is predicated on the need to burn less coal since less electricity is lost in transmission. MP does not appear to have considered the possibility that reducing line losses will result in the current production of electricity being maintained and more of the electricity produced reaching consumers.[193] The record in this proceeding indicates that demand for electricity is increasing.[194] MP relies upon an assertion, unsupported by the record, that the increased generating needs will be met with natural gas-fired generation.[195] The evidence indicates that a reduction of line losses accomplished by the Arrowhead Project will most likely result in more electricity being purchased, not less coal burned to produce electricity. Such an outcome would not reduce mercury emissions. MP's evidence does not support a finding that mercury emissions will be reduced as a result of the Arrowhead Project.

While the evidence is insufficient to show mercury reduction, MP is not required to demonstrate that mercury emissions will be reduced. There is no evidence in this record that mercury deposition will increase in Minnesota from construction of the proposed project. Absent an increase in mercury deposition, the Arrowhead Project does not result in significant impact on the environment through deposition of that pollutant.

Potential for Inducing New Generation Sources

MP asserted that no additional lignite coal-fired electricity generation from North Dakota is likely to be caused by the Arrowhead Project.[196] This assertion is based upon the fact that current coal-fired generators are operating at near full capacity.[197] NAWO, SOUL, and WOLF dispute claims regarding that capacity.

The existing coal-fired generators are operating at between 76% and 82% of their rated capacities.[198] The trend over the last ten years is for those generators to operate at slightly higher percentages of their rated capacity.[199] The increase is attributable to efficiencies developed over time to enable these generators to operate with less "down-time" for maintenance and repairs.[200] These plants are among the

lowest cost producers of electricity available to utilities such as MP.[201] For this reason, there has always been an incentive for these producers to operate at the maximum possible capacity. This incentive exists whether or not the Arrowhead Project is built. The current operating percentages are unlikely to be changed due to the Arrowhead Project.

While marginal efficiencies in electric transmission are likely to result from the additional transmission capacity afforded by the Arrowhead Project, the potential for the construction of new baseline generation always exists.[202] There is no evidence in the record to indicate that new coal-fired generation has been proposed or is sufficiently far into the approval process to conclude that the Arrowhead Project is connected to, or a phase of, some additional project that would include new electricity generation.

Conclusion

MP has demonstrated by a preponderance of the evidence that, with one exception, the Arrowhead Project will not create significant human or environmental impact, as set out in Minn. Stat. § 116C.57, subd. 5. The sole exception is the impact caused by noise generated at the Arrowhead substation by the new transformers to be installed. The impact of that noise can be mitigated by the use of sound barriers, the installation of quieter transformers, or the use of both. With noise mitigation, the Arrowhead Project will have no significant impact and the MEQB may grant the requested exemption from the Minnesota Power Plant Siting Act.

K.A.N.

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[1] Because of a scheduling conflict, the final day of hearing was held in the basement of the Forbes First Methodist Church, Proctor, Minnesota
[2] Tr. at 1688.
[3] MEQB Exhibit 1, at 19
[4] MEQB Exhibit 1.
[5] MEQB Exhibit 8.
[6] Tr. at 1619.
[7] The substation location is further identified as T50N, R15N, Section 31. MEQB Exhibit 1 at 1.
[8] Tr. at 1615.
[9] Tr. at 1616. The twelve lines are as follows: to the south, one 230kV and five 115 kV circuits; to the north, three 115kV circuits and two 230 kV circuits; and to the west, one 250 kV DC line.
[10] MEQB Exhibit 1.
[11] Line 22 turns and heads west to connect with MP's Cloquet substation. Line 70 turns east and connects to MP's Hibbard substation. A portion of Line 70 was rebuilt to 230 kV standards in 1992. MEQB Exhibit 11.
[12] The proposed right of way travels south on the eastern side of the DM&IR railroad tracks and connects to MP's Gary substation.
[13] The proposed line would be 345/230kV for the initial 3.2 miles. The remainder would be 345/115kV.
[14] MEQB Exhibit 1; at 1 and 10; Tr. at 1527-9.
[15] MEQB Exhibit 11, Attachment 28.
[16] *Id*.

[17] Tr. at 1619.
[18] Tr. at 1623.
[19] MEQB Exhibit 1, at 1.
[20] MEQB Exhibit 1, at 1.
[21] *See* REL-17 and REL-18
[22] That power line is designated as Line 22, which is the line currently running from the Arrowhead substation to the Cloquet substation.
[23] MEQB Exhibit 1, at 1.
[24] *See* REL-18 and REL-19; MEQB Exhibit 1, at 2.
[25] REL-19
[26] MEQB Ex. 1, at 2.
[27] Tr. at 1450.
[28] MEQB Exhibit 1, at 10, Public Hearing Transcript, at 165.
[29] Tr. at 1452-3.
[30] MEQB Ex. 14
[31] Tr. at 1542 and 1553
[32] MEQB Exhibit 1, Appendix E.
[33] Tr. at 1567.
[34] Tr. at 1556
[35] MEQB Exhibit 1, at 18.
[36] Id.
[37] Minn. Stat. § 116C.57, subd. 5. Should the MEQB exercise its discretion and deny the exemption, Minn. Rules 4400.3900, provide: "If the board denies an HVTL exemption, it shall indicate the reason and indicate the project changes necessary for approval."
[38] Those impacts are:

A. effects on human settlement, including but not limited to, displacement, noise, aesthetics, cultural values, recreation, and public services;
B. effects on public health and safety;
C. effects on land-based economies, including but not limited to, agriculture, forestry, tourism, and mining;
D. archaeological and historic resources;
E. effects on the natural environment;
F. rare and unique natural resources;
G. application of design options which maximize energy efficiencies, mitigate adverse environmental effects, and could accommodate expansion of transmission capacity;
H. use or paralleling of existing rights-of-way, survey lines, natural division lines, and agricultural field boundaries;
I. electrical system reliability;
J. costs of constructing, operating, and maintaining the HVTL which are dependent on design and route; and
K. adverse human and natural environmental effects which cannot be avoided.

[39] MEQB Exhibit 1 at 12.
[40] Tr. at 312. In its application, MP identified 11 residences as being within 300 feet of the centerline of the route. MEQB Exhibit 1, at 12. MP reduced that number at the time of hearing.
[41] Tr. at 313-4. A homeowner indicated that "From the edge of the existing power line to the middle of our home is 117 feet. Our garage/workshop is 50 feet from the line." Peters Comment, at 2. These distances appear to be from the edge of the existing right of way. This residence appears to be located south of the Midway segment and the right of way is not proposed for widening at the homeowner's location. REL-2.
[42] REL-2.
[43] WOLF Exhibit 1, at 37-8. However, NIEHS has suggested "that the power industry continue its current practice of siting power lines to reduce exposures and continue to explore ways to reduce the creation of magnetic fields around transmission and distribution lines without creating new hazards." *Id*. at 38.
[44] MEQB Exhibit 11, Attachment 16.

[45] In its application, MP concluded that that noise impact would not be increased provided low noise transformers or other sound reduction methods were used. During the hearing, MP indicated it had concluded that noise reduction was not necessary. Tr. at 1234.
[46] MP Exhibit 17, DLV-13. The number indicates the percentage of time the measured noise exceeds the indicated level. Thus, L(90) means the indicated noise level is exceeded ninety percent of the time.
[47] *Id*.
[48] *Id*.
[49] MP Exhibit 18, at 20; Minn. Rule 7030.0040, subp. 2.
[50] MP Exhibit 2, at 8.
[51] MP Exhibit 2, at 8.
[52] MP Exhibit 2, at 7.
[53] MP Exhibit 2, at 7.
[54] MP Exhibit 17, DLV-11.
[55] WOLF Exhibit 3, Appendix, Results of Long Term Measurements.
[56] WOLF Exhibit 3, at 4.2 ("Any location at a distance of less than 2000 feet will have a higher level of transformer noise impact."); MP Exhibit 18, at 6.
[57] MP Exhibit 18, at 9.
[58] WOLF Exhibit 3, at 6.0-7.0.
[59] Tr. at 138.
[60] Tr. at 137.
[61] MEQB Exhibit 1; Appendix F, Bloomberg Letter dated June 10, 1999.
[62] [62] There are also single pole wood supports on the existing line. MEQB Exhibit 1 at 12.
[63] Tr. at 1569.
[64] Tr. at 1565-66. The record is not clear, however, on what approach will be taken at angled locations. Testimony at the hearing indicted that single-pole structures would be used. Tr. at 1552 and 1572. MP has earlier indicated that alternatives such as lattice structures, self-supporting monopoles, and self-supporting twin monopoles (each supporting a separate circuit) could be used at such locations. MEQB Exhibit 11, at 4.
[65] Tr. at 1569.
[66] MEQB Exhibit 1 at 12.
[67] Tr. at 1571.
[68] Tr. at 1572.
[69] REL-18.
[70] REL-2; REL-3.
[71] MEQB Exhibit 1, Figure 5.
[72] Tr. at 882.
[73] Tr. at 323.
[74] MEQB Exhibit 1, Figure 5.
[75] *Id*.
[76] Tr. at 882.
[77] MEQB Exhibit 1, Figures 5 and 6.
[78] Tr. at 896-97.
[79] Tr. at 259.
[80] Tr. at 257 and 291.
[81] REL-3.
[82] REL-3.
[83] REL-3.
[84] REL-2.
[85] REL-2.
[86] REL-2.
[87] MEQB Exhibit 1, at 14.
[88] MEQB Exhibit 1, at 14.
[89] MEQB Exhibit 1 at 14.
[90] MEQB Exhibit 1 at 15.
[91] MP Exhibit 17; DLV-1, Sheets 1-6.

[92] *Id*.
[93] MP Exhibit -17; DLV-4, Sheets 1-6.
[94] By way of comparison, an electric stove emits an EMF field of 21.6 mG at distance of one foot. A person making a photocopy is exposed to an EMF field of 31 mG. MP-17; DLV-6.
[95] MP Exhibit 17, at 6.
[96] Minn. Stat. § 116C.57, subd. 4(1).
[97] WOLF Exhibit 1, EMF-RAPID, at 10. MP Ex. 1 at 8.
[98] NAWO Exhibit 1.
[99] Tr. at 77-78.
[100] Ringstad Comment, *Electrical and Biological Effects of Transmission Lines: A Review* , at 1-19 (Public Comments).
[101] Tr. at 2291.
[102] Tr. at 2292.
[103] MP Exhibit 6, at 38; Tr. at 491.
[104] Tr. 283-84, and 1631.
[105] MEQB Exhibit 1; Appendix D, DNR-NHNRP Letter dated June 21, 1999.
[106] *Id*.
[107] MP withdrew its original proposal to lower noise levels by specifying quieter transformers. Tr. at 1417.
[108] Tr., at 889.
[109] Minn. Stat. § 116B.03
[110] ***People for Environmental Enlightenment & Responsibility (PEER), Inc. v. Minnesota Environmental Quality Council***, 266 N.W.2d 858, at 867 (Minn. 1978).
[111] ***In the Matter of the Quantification of Environmental Costs***, 578 N.W.2d 794, 801 (Minn. App. 1998), *rev. denied* (Minn. Aug. 18, 1998)("…the commission's determination that parties must present a preponderance on the evidence is consistent with established contested case procedure.").
[112] Minn. Rule 4400.3900, subp. 7.
[113] SOUL Ex. 2, at 25.
[114] MP Brief, at 17.
[115] MP Brief, at 17.
[116] ***State by Schaller v. County of Blue Earth***, 563 N.W. 2d 260, 265 (1997)
[117] ***Iron Rangers for Responsible Ridge Action v. Iron Range Resources***, 531 N.W.2d 874, 881 (Minn.App. 1995)(citing ***Audubon Soc'y v. Dailey***, 977 F.2d 428, 435-36 (8th Cir.1992) for the proposition that "agency may base determination of no significant impact on fact that mitigation measures keep the impacts below significant level.").
[118] The issue of whether power lines themselves create a significant human or environmental impact is not properly before the ALJ. There is a power line currently operating in the corridor. The only question is whether the proposal so changes conditions as to create a significant human or environmental impact that does not now exist.
[119] WOLF Exhibit 1, EMF-RAPID, at iii.
[120] WOLF Exhibit 1, EMF-RAPID, at 35. NIEHS suggests that the electric industry maintain its current practice of siting power lines to reduce exposures. At 38.
[121] Tr. at 1455.
[122] MP Exhibit 17, DLV-4.
[123] SOUL Brief, at 3; Tr. at 255.
[124] MP-17, at 5.
[125] MP Brief, at 20.
[126] WOLF Brief, at 24.
[127] WOLF Brief, at 24.
[128] WOLF Exhibit 1, at iii.
[129] Under the classification scheme used by the NIEHS group in the EMF-RAPID study, there are only two categories for substances studied for carcinogenic effects. A substance is a known carcinogen when the causal link between the substance and a health effect is demonstrated. *All* other substances are "possible carcinogens."

[130] Tr. at 456-57.
[131] MP Brief, at 22.

[132] SOUL Exhibits 1 and 2.
[133] MP Brief, at 35.
[134] MP Exhibit 2, at 3.
[135] MP Brief at 35.
[136] MP Reply Brief at 19.
[137] Tr. at 132.
[138] MP-18, at 17.
[139] *Id.*
[140] *Id.*
[141] *Id.*
[142] WOLF-3, Attachment on Meter Locations.
[143] *Id*.
[144] Khosrovani Direct, at 3.
[145] WOLF-3, at 4.2.
[146] WOLF-3, at 7.0.
[147] Tr. at 131.
[148] Tr. at 144.
[149] Tr. 1, at 128.
[150] DLV-11; Tr. at 1404-5.
[151] REL-13, REL-18.
[152] MP Reply Brief, at 22.
[153] *See* Finding 41.
[154] WOLF Exhibit 8.
[155] WOLF Exhibits 5 and 6.
[156] REL-19.
[157] REL-19.
[158] NAWO Exhibit 4.
[159] NAWO Exhibit 4; MP-14.
[160] WOLF Exhibit 4.
[161] DOC Exhibit 4, at 9.
[162] MP Exhibit 27.
[163] *Id.*
[164] MP Exhibit 27, at 2.
[165] MP Exhibit 1, at 6.
[166] WOLF Brief, at 46.
[167] The Arrowhead Project is essentially identified in the WIRES Study as Plan 3j. Plan 3j has a number of "associated projects and upgrades" identified as needed to complete Plan 3j.
[168] WRAO is the Wisconsin Reliability Assessment Organization, a group formed of the MAPP and MAIN reliability councils, utilities in those regions, and interested regulatory agencies acting as *ex officio* members. DOC Exhibit 3, at 1.
[169] MEQB Exhibit 1, Appendix F, Executive Summary of the WRAO Report.
[170] NAWO Brief, at 25.
[171] WIRES is the Wisconsin Interface Reliability Enhancement Study, a report to the WRAO.
[172] DOC-3, WIRES Phase II Report, Appendix C1-3.
[173] A certificate of need is required if the project is a "large energy facility." Minn. Stat. § 216B.243, subd. 2. "Large energy facility" for power lines is defined as:

> (2) any high voltage transmission line with a capacity of 200 kilovolts or more and with more than 50 miles of its length in Minnesota; or, any high voltage transmission line with a capacity of 300 kilovolts or more with more than 25 miles of its length in Minnesota . . . Minn. Stat. § 216B.2421, subd. 2(2).

[174] MEQB Ex. 11, Attachment 28.
[175] MEQB Exhibit 11, Attachment 28.
[176] *Id*.

[177] DOC Exhibit 3, WIRES Phase II Report, Appendix C1-3.
[178] Tr. at 1622.
[179] NAWO Exhibit 26; NWF Public Exhibit, Attachment 10.
[180] NAWO Exhibits 13-16, 18 and 19; NWF Public Exhibit, Attachment 3.
[181] NWF Public Exhibit, Attachments 1 and 2.
[182] NAWO Exhibits 13-16, 18 and 19; NWF Public Exhibit, Attachments 1, 4 and 12.
[183] MP Brief, at 29.
[184] MP Exhibit 3.
[185] SOUL Exhibit 3.
[186] SOUL Exhibit 3, at 7.
[187] SOUL Exhibit 3, at 8.
[188] Tr. at 164.
[189] Tr. at 1837.
[190] Tr. at 1988-89, 1992-93.
[191] Tr. at 192.
[192] Tr. at 1943-45.
[193] Tr. at 2085.
[194] MP Exhibit 3, at 6 (estimating the increase in demand in MAPP over the next 10 years at 8,000 megawatts).
[195] MP Exhibit 3, at 7.
[196] MP Exhibit 30; MP Brief, at 27.
[197] MP Brief, at 27.
[198] Tr. at 161.
[199] MP Exhibit 30.
[200] Tr. at 210-12.
[201] Tr. at 189-90.
[202] The Pimickikamak Cree Nation raised objections to the Arrowhead project, asserting that improving the capacity of electricity transmission into northern Wisconsin would cause Manitoba Hydro to increase its hydroelectric generation capacity. To do so, Manitoba Hydro would need to inundate more of the Nelson River Watershed. Public Hearing Tr., at 17. The Tataskweyak Cree Nation indicated that any increase in the generating capacity from the Nelson River Watershed would be controlled by the Northern Flood Agreement. Public Hearing Tr., at 20. Environmental review would be conducted as part of that process. *Id*. at 21. The MEQB has expressly addressed the limits to the issues that are to be considered in this proceeding. In its Scope Order, the MEQB stated:

> IT IS HEREBY ORDERED, ... that the hearing be limited to impacts from construction or operation of the project facility on human health and the environment experienced in Minnesota. MEQB Ex. 7, at 8.

The environmental and human impacts of expanded hydroelectric generation would not be experienced in Minnesota. Under the Scope Order, evidence of those impacts must not be considered in determining whether the Arrowhead project qualifies for an exemption from the routing process in the PPSA.

ENVIRONMENTAL QUALITY BOARD

ARROWHEAD PROJECT

ORIGINAL

MARCH 15, 2001

TAPE TRANSCRIBED BY: Janet Shaddix Elling, RPR

ISA Combined Application
Docket Nos. E015/CN-25-111 and E015/TL-25-112
Appendix J
Page 39 of 130

(Side A of Tape.)

CHAIR HUGOSON: We'll call the EQB Board back to order, and we're going to be taking up the Arrowwood -- Arrowhead transmission line issue. What -- just so everyone knows how we're going to proceed, we'll have EQB staff do the presentation to the -- to the Board. There is a sample resolution that is in your packet here that we'll be looking at, in fact I'd ask somebody to move that to get it on the floor after Mr. Mitchell's presentation.

UNIDENTIFIED: I don't have a copy of the resolution.

CHAIR HUGOSON: Okay. We'll see that you get one.

UNIDENTIFIED: (Inaudible).

CHAIR HUGOSON: In that book right there.

And then there has been a memo that's gone out to the attached -- to a list of the people that have been parties to this issue, stating that we'll take no more than ten minutes of testimony from each of those groups. I know we have a number of cards from people in addition to that. I'm going to ask that what everyone that is

planning on testifying do is that they would address their remarks only to the resolution that is before the Board, because that's the issue that the EQB Board here is addressing themselves to, and the additional testimony that we'll take beyond the intervenors list would be somewhat based on time, and certainly, and I would expect that people would not repeat things that have already been placed before the Board.

Mr. Bernstein?

MR. BERNSTEIN: Mr. Chairman, I would like to, on the advice of counsel, I'm going to recuse myself from any voting or any discussion. And I am privy to information about this particular matter, which other Board Members are not, and material that's not on the record. However, I planned on leaving, but at this point we don't have a quorum if I don't -- if I don't stay. So if I promise not to make faces or gestures, could I at least stay here to maintain a -- maintain the quorum?

CHAIR HUGOSON: I think that would be a good idea, Mr. Bernstein. I appreciate that.

UNIDENTIFIED: Put a shield around you.

UNIDENTIFIED: Might not be a bad idea.

UNIDENTIFIED: And then if you misbehave we'll turn your chair around.

MR. BERNSTEIN: Thank you.

CHAIR HUGOSON: The -- just so everyone is aware, we have three members that will be returning here shortly, and so we will be having a quorum.

I would also ask that we do not have demonstrations in this room, so we'd ask those folks in the back, please, to lower the signs and what you're doing back there.

UNIDENTIFIED: (Inaudible) Manitoba power, this is Manitoba Hydro (inaudible).

(Inaudible conversation.)

CHAIR HUGOSON: This isn't a place where we're looking at doing it, we want things that are going to be on the record here for testimony and so forth. So I would ask, respectfully ask you to not do that. Thank you.

We will proceed, then, with Mr. Mitchell.

MR. MITCHELL: Thank you, Mr. Chair, Members of the Board. I'm Alan Mitchell, I'm the manager of the power plant siting program for the EQB. In the audience today are Bob Cupit and John

Heinz from the power plant siting staff as well.

Minnesota Power is proposing to build a high voltage transmission line from the Arrowhead substation at Hermantown, north and west of Duluth, about 250 miles down to a substation near Wausau, Wisconsin. About 12 miles of the line will be in Minnesota.

Under the Power Plant Siting Act a permit from the Environmental Quality Board is required to construct a high voltage transmission line, and a high voltage transmission line is a line capable of carrying more than 200,000 volts, 200 kilovolts of electricity. This line is proposed to be built at 345 kilovolts. So the Power Plant Siting Act is applicable here, and a permit is required to construct a high voltage transmission line. But the Act provides that a person proposing to build such a line may apply for an exemption from the requirements to get a permit from the Environmental Quality Board.

If the Board grants an exemption for a high voltage transmission line, what it means is that a permit from the Board is not required, but the applicant will be required to go back to the local authorities through which the line passes,

the counties, the townships, the cities, and obtain the local approvals, zoning approvals, conditional use permits, whatever it might be from the local people. So if the Board grants an exemption for this line, then Minnesota Power has to go to the local authorities for approval.

The standard for granting an exemption under the Power Plant Siting Act is a determination whether the project will create significant impacts on human health or the environment. That's -- that's the standard that the Board needs to apply to determine whether to grant the exemption.

At the request of Minnesota landowners along this line, a hearing was held in Duluth back in August and September, around Labor Day, to gather evidence regarding this project and whether the exemption should be granted.

Chief Administrative Law Judge Kenneth Nickolai presided at the hearing, considered all the evidence, and issued his report on January 29th and found that the project would not create significant impacts on human health or the environment and recommended approval of the exemption.

The staff has reviewed the record and the Administrative Law Judge's report, and we have come to the same conclusion, that there will not be significant impacts, and we have recommended that the Board grant the exemption.

The line is about 250 miles long from Duluth to Wausau, essentially, and it's a controversial line, as you know from the parties that have participated, and many of whom are here today. It's only 12 miles long in Minnesota, along primarily existing right-of-way, but this much longer stretch in Wisconsin makes it a very controversial project, and there is a proceeding before the Wisconsin officials that is underway as well.

The public participants in the hearing have raised a number of issues regarding this line, and we've addressed them as we've seen them in a memorandum that's in your packet. And I'd just like to quickly take you through a couple of those, and then I know the parties are anxious to have their time to address those as well.

One issue relates to the air pollution that's going to result from the generation of the power that may find its way onto the Arrowhead

transmission line, power, or electricity that's going to be transmitted down this line. You had before you, when you came in this morning, and we have provided to the parties, a copy of a memorandum from Commissioner Studders who raises this issue in her memorandum.

The parties did address this matter during the hearing, particularly the issue of whether more mercury is going to be emitted in Minnesota. But I'm sure you're aware, this is quite an elusive issue, to determine what are going to be the air pollution impacts from generation of electricity in the future. There are going to be plenty of opportunities in other forums to address this very issue. Energy planning efforts by more than just Minnesota. Air pollution permitting processes, if somebody proposes a new power plant or to expand operation of an existing plant beyond present permit limits. And you'll have the specific characteristics to plug into the models and into the mathematical equations to calculate the more precise environmental impacts on air pollution from generating the electricity.

At this time we think Commissioner

Studders has made a good suggestion in her memorandum, to condition the granting of any exemptions so that Minnesota Power cannot expand the sub -- the substation at Arrow -- at Arrowhead beyond what this exemption would allow and what they've proposed at this time.

Angela, if you could pass out that one-page document. We've -- the staff has drafted an amendment to one of the findings to recognize the precise capability, the technical capability of the transformers that will be installed at the substation. And a new condition that emphasizes that any expansion, any proposed expansion by Minnesota Power, beyond the present capabilities of the substation, would require them to come back to the Environmental Quality Board for approval. We have provided this document to the parties and, you know, they'll have an opportunity to comment upon that when their time comes here to speak.

Another issue relates to the reliability of this line. Is it going to enhance the service of electricity to Minnesota and Wisconsin customers. Some of the parties challenge whether this line is really going to enhance electrical service for the customers, and they argue there

are better things that could be done than to build a 250 mile long high voltage transmission line. Additional generation, distributed generation, maybe another transmission line. The Wisconsin officials are addressing this to some degree, but there's nothing in the record that suggests that the performance of this 12-mile segment of the line or the line entirely is going to create significant impacts on Minnesota's environment or on human health in Minnesota.

The Administrative Law Judge found that the line would -- would indeed enhance reliability, there's no quantification of that, but it will enhance reliability. The staff agrees with that. We're not making any judgments on what else Minnesota Power or any other utility or any other person might do, but we have concluded that this line is not going to cause significant impacts.

The third issue relates to the environmental impacts from -- from construction of the line and mitigation measures that might be implemented. There was some focus at the hearing on how to protect wetlands in Minnesota that are along this line, and trout streams, and there was

an issue regarding the noise from the operation of the transformers at the substation.

The company has agreed to a number of mitigating measures that the public and the Administrative Law Judge both recommended. We, the staff, have put them in the proposed Findings of Fact, Conclusions and Order that you have before you, requiring the low noise transformers, the mitigation in wetlands, and other things like that. So there are a number of conditions that we would recommend you include with the granting of the exemption, if that's what happens, what you do.

There are a couple other issues, we've addressed them in our memorandum, electromagnetic fields, EMF, fiber-optic cables, cost comparisons, I'm not going to go into those, we can answer questions if you have some.

So I would remind you that the test for an exemption from the Power Plant Siting Act is whether the project will create significant impacts on human health or the environment, and if you grant the exemption, Minnesota Power has to go to the local authorities for appropriate permits from them.

The Administrative Law Judge said, no, it won't cause these significant impacts, the staff agrees with that. And we have provided a resolution in your packet, we've drafted a Proposed Findings of Fact, Order and Conclusions. We have suggested some amendments to some of the findings of the Administrative Law Judge, some corrections, we think, and expansions in some cases. You have the additional language that we just drafted yesterday in response to Commissioner Studders' memorandum, which we would recommend that you include. And with those conditions we recommend adoption of the -- or the granting of the exemption.

CHAIR HUGOSON: Ms. Enzler?

MS. ENZLER: I just have a basically background question. I was diligently reading all of this information, and I have a question about the definition of reliability. As I understand it, reliability pertains to system security, which I understand, but also pertains to adequacy of supply. And I am not precisely clear in my mind the distinction between adequacy of supply versus increased capacity. If you could explain that distinction so hopefully I understand.

MR. MITCHELL: Mr. Chair?

CHAIR HUGOSON: Mr. Mitchell.

MR. MITCHELL: And if I can't explain that distinction, what's the fall-back here? Can I defer to some of the parties that can address that? I know that WOLF and Ms. Overland raised that issue partly in their material.

CHAIR HUGOSON: Mr. Mitchell, why don't you give it your best shot and then we'll have -- we'll hear from other parties along the way.

MR. MITCHELL: Well, I think the reliability -- reliability issue goes mostly to contingencies that might happen. Storms knocking out transmission lines, storms knocking out substations, or mechanical problems knocking out substations, maybe problems at the generating plant. But what happens when you have these upset situations, how are we going to ensure that we don't have power outages. And this whole transmission line system is a big grid, they're all connected, power is flowing in all different directions, and how does this line help to ensure that if we have a storm that knocks out a King line, how is this going to ensure that Minnesota and Wisconsin customers continue to have power.

MS. ENZLER: The problem --

CHAIR HUGOSON: Ms. Enzler.

MS. ENZLER: As I read the Department of Commerce's brief, that whole issue, you know, knocking power lines down and that type of thing relates to the issue of the security of the system. And the Department also defines reliability as adequacy of supply. And I understand (inaudible). What I'm not clear on is what does it mean by adequacy of supply? Does that mean that you want a system that you can maintain current supply, or is it a system that is designed to, as demand increases, increase the amount of power that goes over it to meet those demands? I'm not clear about the distinction between adequacy of supply and increased capacity, which seems to be a very clear distinction that is made by the parties in this case. And so I'm wondering if you can just explain that part of the reliability issue for me.

CHAIR HUGOSON: Mr. Mitchell.

MR. MITCHELL: Mr. Chair, I don't -- I don't know if I can do that, and I'm probably not the best person to try to do that. So I -- I touched on the reliability issue for making sure

the power is there all the time. As far as ensuring in the future that we have an adequate supply, I think that's what the whole energy planning process is about. Both by government and by the utilities through the Mid Area Continent -- Mid Area Continent Power Pool and the other organizations that the utilities have formed to do that kind of planning. To make sure that given the fact that demand for power is increasing at certain percentages each year, on average, how are we going to ensure that there will be enough electricity in the future. And how are we going to ensure that we can get it from the point of generation to the point of demand.

CHAIR HUGOSON: Okay.

MR. MITCHELL: The other parties can also --

CHAIR HUGOSON: Mr. Maline and then Commissioner Garber.

MR. MALINE: I have a question that I believe relates to Commissioner Enzler's question. Many times before this Board there are questions of -- of need, and every time I look for justification for consideration of need I don't find it in our -- in our rules and statutes.

I see in the original application exemption a list of governmental permits that are required, but the Minnesota Public Utilities Commission is not among them. Is there -- is there no -- is there an evaluation of need that has gone into this, and if -- is there a body that is identified as responsible for that, and finally, if not, what -- what puts it below a need to present information to somebody to demonstrate need?

CHAIR HUGOSON: Mr. Mitchell.

MR. MITCHELL: Mr. Chair, Mr. Maline, the Public Utilities Commission is the body in this state which makes the need decision for large electric generating plants and high voltage transmission lines. But their jurisdiction has certain cutoffs. For high voltage transmission lines it has to be a certain number of miles. And I think for a 345 line it's 25 miles or longer. This line is shorter than the jurisdiction of the Public Utilities Commission, so there is no need -- no need analysis required in Minnesota. Wisconsin is going through its own process.

In addition, Mr. Sullivan advised you that there's a lot of activity in the legislature

this year with energy bills. And one of the proposals that your staff has suggested to them for changes in the Power Plant Siting Act is to require a certificate of need for any interstate line. Interstate, regardless of length. And of course that would go to the Public Utilities Commission under the existing statutory format. But right now there is no need analysis or need requirement.

MR. MALINE: Thank you.

CHAIR HUGOSON: Commissioner Garber.

MR. GARBER: Mr. Chair, I think it's important also to add to what Mr. Mitchell said, that notwithstanding whatever the EQB does, the DNR has responsibilities to issue crossing permits to safeguard trout streams, wetlands, existing trails, or any other natural resource consideration.

CHAIR HUGOSON: Okay. Thank you. Any other comments from, from -- or questions for Mr. Mitchell?

MS. THORVIG: Mr. Chair?

CHAIR HUGOSON: Yes, Ms. Thorvig.

MS. THORVIG: I just wanted to say that we have looked at the amendment that Mr. Mitchell

has proposed to you in response to Commissioner Studders' memo and we feel like that does satisfy her concern.

CHAIR HUGOSON: Okay. The Chair would entertain a motion to move the resolution incorporating the amendment that has just been passed out, or was passed out to you by Andrea a few minutes ago. Is there -- Commissioner Garber makes the motion. Is there a second? Seconded by Mr. Maline. The amended, or the -- the resolution with the incorporation is before the Board, and at this time we will begin to take testimony from the people that have been involved with -- with this issue. And I'm going to take them in this order.

UNIDENTIFIED: Mr. Chair? May I suggest that we recess until we have a quorum of decision-makers here so that our argument is heard (inaudible) Board, those (inaudible).

CHAIR HUGOSON: Yeah, my -- my thought was is that we were going to start with Minnesota Power making their presentation, and if they would prefer not to proceed until everyone is here, that's up to them. And then assuming some of the other folks would want to wait, I would -- I would postpone at that point. So the order I was going

to go in or would go in even when we do resume, would be Minnesota Power would be first, Save Our Unique Lands would be second, the World Organization for Landowner Freedom would be third, and the North American Water Office would be fourth.

And at this time I will ask Minnesota Power if you would like to proceed or would you prefer to wait?

MS. AMBERG: We're certainly prepared to proceed. (Inaudible).

CHAIR HUGOSON: Fine. Okay.

MS. AMBERG: (Inaudible).

CHAIR HUGOSON: Fine. Okay.

MS. ENZLER: I have one more question of staff on the proposed order now that it's been (inaudible).

CHAIR HUGOSON: Okay.

MS. ENZLER: I have a question on proposed revision on paragraph number 54.

CHAIR HUGOSON: Can you speak a little more into the microphone, please, too? I think it might be easier.

MS. ENZLER: Certainly. They proposed an amendment to paragraph 54 of the Administrative

Law Judge's order, and the amendment is, I think is designed to clarify the ALJ's order, but the amendment as drafted by staff reads that the Arrowhead project will not result in a significant impact on human health or the environment in Minnesota from the generation of electricity to be transmitted on the proposed transmission line. And having read major portions of the administrative record and the ALJ's determination last night, I guess my question to staff is whether they can come to the same conclusion I do, which is that there isn't extensive testimony on the record regarding the impacts of the generation of electricity, and so that, as I read it, it's not possible to reach a conclusion on the generation of electricity one way or the other regarding the health impacts in this record.

CHAIR HUGOSON: Mr. Mitchell.

MR. MITCHELL: Mr. Chair, Director Enzler, there was discussion of that issue, and the parties did not go into great detail and a great analysis in their briefs, and the Administrative Law Judge did not either. There's a lot more that could have been done from the evidence that was in the record. We think the

assumptions, that's all they are, they're assumptions. And we think regardless of the assumptions you make it leads to a conclusion that there's not going to be a significant impact from the generation of power, wherever it is, because of the construction of this line.

CHAIR HUGOSON: Ms. Enzler.

MS. ENZLER: I would propose that we amend number 54 since we have before us really the construction and operation of this line and not the generation of electricity. And I propose that we amend this finding to say that the Arrowhead project will not result in a significant impact on human health or the environment from the construction and operation of the proposed transmission line, and delete the generation of electricity to be transmitted.

UNIDENTIFIED: Construction and operation of generation?

MS. ENZLER: Yes.

MR. MITCHELL: Mr. Chair, that amendment is certainly fine.

(Inaudible discussion.)

CHAIR HUGOSON: Ms. Enzler, I would ask you to hold that motion for now, if you would,

please, because until we have the other members back --

MS. ENZLER: That's fine. Certainly, I certainly will do that.

CHAIR HUGOSON: Okay.

MR. SULLIVAN: Mr. Chairman?

CHAIR HUGOSON: Mr. Sullivan.

MR. SULLIVAN: Yeah, just to confirm Mr. Mitchell's comment, I think that that, certainly from the staff's perspective, it would be a change and there wouldn't be objection to it.

CHAIR HUGOSON: Okay. But I think just for proper procedure we should wait.

MS. ENZLER: Certainly.

CHAIR HUGOSON: If we could.

Ms. Amberg, if you would care to proceed, please, and if you'd identify yourself for the tape, please.

MS. AMBERG: Thank you, good morning. My name is Deb Amberg, I'm an attorney with Minnesota Power, and it's my pleasure to appear before you this morning and request your approval of Minnesota Power's application that we be exempt from the full requirements of the Power Plant

Siting Act.

Back in November of 1999 and again in May of 2000 --

CHAIR HUGOSON: Excuse me, Ms. Amberg, I'm sorry to interrupt and I apologize, but maybe at this time, Mr. Bernstein, we will officially acknowledge your recusal, and thank you for lending us your person. Such that it has been.

MR. BERNSTEIN: You're welcome.

CHAIR HUGOSON: So that we could continue.

MS. ENZLER: And for behaving himself.

UNIDENTIFIED: Exactly. For sitting in for a quorum.

(Inaudible conversation.)

UNIDENTIFIED: Well, thank you for your -- your public service.

MR. BERNSTEIN: You're welcome (inaudible).

CHAIR HUGOSON: And, Ms. Amberg, if you would not mind starting over, please, I don't mean to interrupt your testimony.

MS. AMBERG: Good morning. Welcome back. My name is Deb Amberg and I'm an attorney for Minnesota Power, and it's my pleasure to be

here this morning and to request your approval of our application to be exempt from the full requirements of the Power Plant Siting Act.

Back in November of 1999 and again in May of 2000 this Board ordered a full hearing to assemble a record as to whether the construction and the operation of the proposed line would create a significant human or environmental impact in Minnesota.

In late August and early September of this year Chief Administrative Law Judge Ken Nickolai did just that. He listened to two full weeks of testimony and cross-examination from the very parties who appear here today. The Judge listened to extensive testimony about the interconnected network of the electrical grid and how events in one place can have effects far away. He heard about the specific weaknesses of the electrical system in Minnesota and Wisconsin, and that a group of utility experts from Wisconsin and Minnesota gathered to consider the problem and unanimously recommended the Arrowhead-Weston line as the best solution to the most severe of the region's transmission deficiencies.

He also heard about the ways to think

about what this line is and what it is not. In response to Director Enzler's question earlier, this line is not about increasing the electrical supply to the region. The adequacy of supply, on my understanding of the NERC definition, is having sufficient energy generated to meet the needs, the load, the demand of the users. The security of the system is having the proper facilities in place that will move that energy from the generation to the end-user, to the demand, to the load.

CHAIR HUGOSON: Ms. Enzler.

MS. ENZLER: I might inquire on -- thank you for that clarification, and you said adequacy relates to sufficient energy to meet the needs. Is that the needs as they change over time, that is as demand increases the needs increase, or is that needs as of a date certain?

MS. AMBERG: Generally NERC would look at it and say that it's to meet the needs as they exist, with a certain reserve margin. And that reserve margin, then, would account for the various fluctuations from day to day. But they do forward planning in order to make sure that going forward enough generation exists to meet the needs

of the load. But generally speaking, adequacy of supply would just look at what are the needs today. So you would -- if you had a number of generators that were offline for whatever reason, due to maintenance or breakdown or whatever, then you might not have adequate supply for the needs at that particular point in time. So generally it refers to at the present. They do include planning processes to try to account for projected growth.

MS. ENZLER: Okay.

CHAIR HUGOSON: Okay, thank you. Please proceed.

MS. AMBERG: Thank you. This line is about increasing the security of the transmission that delivers the existing supply. The transmission system has reached a state in which requests for power transfers must be frequently denied because they cannot be reliably delivered to the end-users.

There was testimony from representatives of MAPP, the Mid-Continent Area Power Pool, that that is indeed the case and that those -- that is happening more and more frequently, that the requests to use the transmission system must be

denied. They only allow certain amounts of transfers to be made on this system without overloading the system, and once systems get overloaded then you have a jeopardy to the reliability of the system.

So what this line will do is it will contribute significantly to the reliability of the delivery of energy in Minnesota, as well as Wisconsin, as well as the region as a whole.

Judge Nickolai also had the benefit of the views of the Department of Commerce, the state's lead energy policy agency. In their brief the Department stated that they have an interest in ensuring that electricity is transmitted reliably, efficiently, and in harmony with sound energy policy. In their brief the Department of Commerce stated quite clearly that the Arrowhead project would contribute to system security by mitigating a number of factors, and also by specifically allowing the system to be recovered after an outage of a specific line, and much more quickly. It would also reduce the likelihood of there being a double outage through a common event. We've been referring to that as geographic diversity. But if you have your two major lines

sufficiently far apart then you're not going to have a single event, such as a weather event, take out both lines.

The Department of Commerce also stated in their brief that the Arrowhead project would not result in greater transfer from the existing North Dakota lignite plants or for Manitoba Hydro.

You asked Judge Nickolai for a record and he did that. He did it in a very thorough, detailed manner. He listened to all of the evidence that was offered, those which he considered to be relevant to the issue. He went out and he physically looked at the proposed route. He looked for those potential impacts. He found none. He heard the arguments and looked at each piece of evidence piece by piece. Frankly, I don't think you could look for a more detailed review of what was offered to him.

In SOUL's exceptions they come forward and they've asked for some new conditions, new items that were not part of the evidentiary record. We agree with the conditions which were recommended by the staff, and we don't agree that SOUL's requests are appropriate to be brought at

this point.

In NAWO's exceptions to the ALJ report, he criticizes the Judge, which I think is grossly unfair. The Judge was critical of all of the evidence. He didn't find in Minnesota Power's favor on every point. But he did find that there was no evidence that mercury emissions would be increased as a result of the construction of this project.

In WOLF's exceptions they simply argue that the Judge should have seen things their way. He simply didn't.

After considering all of the evidence offered to him, Judge Nickolai was crystal clear in his findings. Minnesota Power has demonstrated, by a preponderance of the evidence, with one exception, that the project will not create significant human or environmental impact. The sole exception is the impact of the noise created by the -- by the transformers, and Minnesota Power has agreed to install low noise transformers, which will mitigate the impact of that noise. The ALJ specifically found that with noise mitigation the Arrowhead project will have no significant impact and that the MEQB may grant

the requested exemption.

As was discussed earlier, granting our exemption is not the end of the regulatory process, it is only the beginning. Throughout the final planning, construction and operation phases various state and local agencies will continue to have jurisdiction over the line to ensure that the public is protected. The DNR and the Army Corps of Engineers will have jurisdiction over all of the wetlands and the rivers and the streams which will be crossed as a part of the project. Midway Township, the city of Hermantown and the city of Duluth must all issue individual permits that will allow each one of them to review the construction practices to ensure that their local interests are protected. The Department of Transportation will also be involved in any crossings of highways and roads, as will the St. Louis County Highway Department.

As far as the amendment to the findings as was offered today, this was the first that we had heard about it, and we've had a little bit of time to talk about it. It strikes us as something different from what we've seen in previous conditions. This is something that's looking

specifically at the operations within the substation, and looking at something which in and of itself doesn't have a direct impact, there's no air emission, there's no water discharge or anything like that. It is looking at, if this were to be changed and increased, and actually it engages in a bit of speculation, then, about what would be the impacts which could be allowed someplace outside of the state. It strikes us as a bit of a new direction for the MEQB, in setting this condition as far as the transformer limit, but we do agree that what we had proposed was an 800 MVA transfer, and that is what is in our application.

We are concerned with how to work with the condition if it is to be included going forward. For example, if there's a need to increase the transfer capacity of the transformers, what is the process to be used and what is the standard to be applied to that.

We agree with Mr. Mitchell's comments about the future opportunities to examine specific projects, and we're a bit concerned about setting a condition here which would act as a proxy for other projects which might be proposed outside of

the state.

But, in summary, we agree that the condition does accurately reflect what was in our application, the 800 MVA transfer. And we're available for any questions you might have.

CHAIR HUGOSON: Thank you. Ms. Enzler, do you wish to move that -- your motion or your amendment at this point?

MS. ENZLER: Yes, I will move our amendment, my amendment at this point, and that is that we amend finding 54 as amended by the staff.

CHAIR HUGOSON: Excuse me. Just so that the people that were not in the room before, so they understand what you're referring to, in the -- in the book or the material that you were given, it's under the last, item eight, under the Findings of Fact where it refers to finding 54. And Ms. Enzler is making reference to that, that piece.

MS. ENZLER: And staff has acknowledged, and in fact Ms. Amberg has just acknowledged that the Court found that it was the construction and operation of the line that will not result in a significant environmental effect, the proposed amendment reads the generation, so I propose and

would (inaudible) an amendment to finding 54 that would be the Arrowhead project will not result in a significant impact on human health or the environment in Minnesota from the construction and operation of the proposed transmission line.

MS. AMBERG: Chair Hugoson, for the record, we have no objection to the amendment.

CHAIR HUGOSON: Okay. Is there a second?

UNIDENTIFIED: Second.

CHAIR HUGOSON: A motion has been made and seconded. All those in favor say aye.

ALL COMMISSIONERS: Aye.

CHAIR HUGOSON: Opposed, no? Motion is carried.

Also, for those of you that joined us late, there -- when the issue -- the resolution that's before us incorporates the amended finding number 11, that is on a single sheet of paper there, so that's -- that's the resolution that's before us.

MR. TINKLENBERG: Mr. Chairman?

CHAIR HUGOSON: Commissioner Tinklenberg.

MR. TINKLENBERG: The amended number 11,

the finding, not condition 10?

CHAIR HUGOSON: Both of those are included, is my understanding, yes. And that's, that's the motion that's -- that we're addressing right now. It's been moved and seconded. Obviously we haven't done any voting on it. Any other questions for Minnesota Power? I'm sorry, Ms. Enzler.

MS. ENZLER: Just a real brief question. In reading all the documentation there was a great deal of reference about a fiber-optic line that will be constructed in this right-of-way at the same time. Can you tell me what that line will be used for?

MS. AMBERG: The fiber-optic line is an item that we are continuing to evaluate what actual construction we would use. We have the option of using power line carrier versus the fiber-optic. At this point we plan to use power line carrier and not actually construct the fiber-optic. The fiber-optic is far more expensive, and unless there were to be someone who wanted to subcontract or to use the excess capacity, there's no financial reason to build that.

CHAIR HUGOSON: Ms. Enzler.

UNIDENTIFIED: (Inaudible).

MS. ENZLER: I might have heard it wrong, 'cause I'm a little confused, is the construction of the fiber-optic line, assuming it's constructed, is it to be used for operation of the transmission line, or what's the purpose, what would be the purpose of constructing it? Why would you want it?

CHAIR HUGOSON: Ms. Amberg.

MS. AMBERG: Chair Hugoson, Director Enzler. The fiber-optic, or some amount of the fiber-optic is necessary, or some form of communication, which the fiber-optic could be, is necessary for communication on the line. So if the full fiber-optic capacity that we've requested permission to build were constructed, part of that would be used for communication purposes on the line itself. Communicating switches that might need to be closed or opened or actual operational aspects of the line.

We've actually asked for permission to build more than what would be necessary, and that is because economically you can put up the greater capacity for not a great deal more cost than what

is the minimal needed to operate the line. And then there would be the opportunity for other telecom needs in the region to be met by using that excess capacity. Any contract that would be entered into for the excess capacity would have to be approved by the Minnesota Public Utilities Commission, and they would have jurisdiction over the rate impacts which would result from that contract.

CHAIR HUGOSON: Okay. Any other questions for Ms. Amberg? Hearing none, thank you very much.

MS. AMBERG: Thank you.

CHAIR HUGOSON: At this time I would ask Ms. McGillivray, I believe it is, from the Save Our Unique Lands group.

Board Members, we're allocating ten minutes for, excuse me, each of the presenters. It might be helpful if we can hold any questions for them until after they've finished their presentation. It's a little easier for me to time it that way.

So, welcome, welcome to the Board, please share your testimony.

MS. McGILLIVRAY: Thank you.

CHAIR HUGOSON: And if you'd identify yourself on the tape, please.

MS. McGILLIVRAY: Sure. Thank you, Mr. Chair. Thank you, Board Members. My name is Pam McGillivray, I'm the attorney representing Save Our Unique Lands. And actually I just have a short statement today because I know there's so many other members of the public who would also like to address the Board, and as you know, there's been plenty of filing in this matter already.

Just to start with, I would like to agree with the points that Commissioner Studders made in her memorandum earlier this week, and agree with her that the record does indeed show that the line will allow for the increase of bulk electricity transfers from -- from the west. And our concern, of course, is from North Dakota, where lignite generation will be increased, leading to the release of mercury and other pollutants and transferring those into -- through the atmosphere to Minnesota and having those be deposited in lakes and rivers in Minnesota.

That information, as Commissioner Studders indicates, is part of the record, and it

is at this time that this Board has jurisdiction over preventing that environmental impact. Minnesota Power referred to other -- other permits that local governments will have, and the DNR. However, those will not stop the availability of using that bulk transfer from North Dakota. This is the opportunity, not a future opportunity, as Ms. Amberg stated, but this is the opportunity to decide that this warrants further study, that it should be through an environmental impact assessment by denying this application.

Mr. Mitchell pointed out that equations and calculations can be done to measure whether or not the amount -- what the amount of those increased depositions will be, but he alluded to later planning, after this is built and we can increase bulk transfers from the Dakotas, that will already be done and this line will already enable that process.

So what SOUL is urging this Board to do is to exercise their jurisdiction right now and to require that further study so we do have the true measurements, as Mr. Mitchell referred to, of this potential impact.

And then further I would just like to

address the fiber-optic issue that just came up. This is an item of great concern for members of the public both in Wisconsin and those along the right-of-way in Minnesota, in that it will enable Minnesota Power to provide telecommunications use of these fiber-optic lines, if they're used, on the backs, essentially, of those landowners, on their easements. So the reason that SOUL provided that condition in its -- in its exceptions was not to -- was -- first of all, the condition was provided without waiving anything, we still are urging the Board not to approve this line. But if the Board does, we hope that they would put a condition requiring that a third party lessee be found so that it does indeed, as Ms. Amberg says, go through the Public Utilities Commission, and make sure that that's the best decision for those landowners, and not allow them to reap the financial benefit from those fiber-optic lines.

And, in conclusion, you are the final decision-makers on this. Although the ALJ did provide his recommendations and found that there are no significant impacts, the record clearly shows that there is potential for significant impacts from this line. And, again, what we are

asking is that you deny this application so that we will both do the process of an environmental impact assessment from the Power Plant Siting Act from getting a full construction permit. And then if there are any questions I'm available to answer the questions.

CHAIR HUGOSON: Okay, thank you. Are there any questions for Ms. McGillivray? Seeing none, thank you so much for your testimony.

MS. McGILLIVRAY: Thank you.

CHAIR HUGOSON: Next I would ask Ms. Overland to come forward, please, and identify yourself for the tape, and you're representing the World Organization for Landowner Freedom. Welcome to the Board.

MS. OVERLAND: How would you like me to deal with handouts?

CHAIR HUGOSON: Angela will handle that, please.

(Inaudible conversation.)

CHAIR HUGOSON: Ms. Overland, is this material that's already in the record?

MS. OVERLAND: One thing that isn't is pictures of Linda's house. Is that -- and the other things are copies.

CHAIR HUGOSON: I'm sorry, that would not be appropriate, because it's not part of the -- there's a deadline for material having to be presented, and so that becomes an issue, it becomes a problem.

MS. OVERLAND: So we can't show pictures of Linda's house?

CHAIR HUGOSON: Right.

MS. OVERLAND: Okay. And that's the large one, and then the others are copies of statute and rules which I'm sure everyone here needs to know, and the other is a copy of one page of a case. It has been argued. It's a Minnesota case.

CHAIR HUGOSON: Let's present it to counsel here first. I apologize, but we obviously have to treat everybody equally.

MS. OVERLAND: Um-hum.

CHAIR HUGOSON: Again, if you'd state your name for the tape, please.

MS. OVERLAND: Yes. Good morning, or -- it's still morning. I'm Carol Overland, representing WOLF, which is World Organization for Landowner Freedom. This is Linda Hanson, one of the founders of WOLF. And we wanted to present

photos of her home because this affects Linda personally. She looks out her deck and sees a row of trees outside of her house, and that row of trees will be cut down and replaced with a 345 kV power line if this line is built. And that's why she started WOLF and that's why we're here today.

There's two rather simple and concrete issues to consider first before we get into a little more ethereal things.

First, the noise of this line, you were concerned about noise of substation. The noise of the line is increasing eightfold. That's a large issue. And it's going to be an important issue a along the entire line. Everyone who lives along that line will hear it.

Second, when we're looking at forced upgrade certificates of need, the (inaudible) Arrowhead and/or the black area Arrowhead lines are going to be upgraded to power this line. And they're about 50 miles long, both of them. And we should make sure that these lines are not permitted to be upgraded without separate proceedings before the EQB and the PUC.

Now, you need to look at reliability. What I've handed out, the first handout was a copy

of state statute, 116C.53, your citing authority. And if you look at subdivision one, you're to cite -- in accordance with the policy of the legislature you're supposed to choose locations that minimize adverse human and environmental impact while ensuring continuing electric power system reliability. Reliability, ensuring reliability, is a part of your job. And in routing considerations, this was 4400.1310, this was first raised by Mr. Wagenius up in Duluth on the record, and if you'll look at subpart 1 (i), you're to look at the electrical system reliability. This is an issue for consideration here. And so when you talk about reliability, what does that mean? Well, the memorandum from staff says it's WOLF that's defining reliability in this way, but it's not WOLF. It's the North American Reliability Council. On page 9, this is on the record, the reliability assessment from 1999, and it defines adequacy as the ability of the electric system to supply aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security, that's the ability of the electric system to withstand sudden disturbances, such as electric shortcircuits, or unanticipated loss of system elements. That is not, as Minnesota Power said, the ability to move the electricity around. There's a big difference there. Security is the line's crashing, and that is the basis for their claim for need of this line, and that's a false claim.

The big difference here, when you're looking at adequacy and whether or not this fills adequacy, you need to look at the shift now from just serving customer load to the desire of utilities to move bulk power around. That is why we're having increased demand. It isn't that demand is increasing so much as they want to move the cheap power from Minnesota -- from Manitoba Hydro from North Dakota through Minnesota, through Wisconsin, out to Illinois. And that's what this is about. And why do we care that there's two types of reliability? The blackouts and outages that are cited by proof, those are systematical issues. Let's be really clear. They're not system security issues that we're talking about. So we should be clear on that. The system

security issues are not a valid rationale to expand bulk power transmission.

If you're looking at reliability, if you want to look at systematic liciti (phonetic), how do you do that, you look at LOLE, which is loss of load expectation. Has Minnesota Power done an analysis? No. You look at relative risk studies and risk analysis. Have they done an analysis? No. You look at frequency and duration studies of power outages. Have they done that? No. You look at blackout risk mitigation. Have they done that? No. (Inaudible) analysis, there's not one in this proceeding.

So what are we basing this on? And all of this is in the record, and I can give you transcript cites, if you like. Hopefully you've reviewed the transcript. They have not done anything to demonstrate any rationale for a system adequacy basis for this line. They've only used system security.

The problem of the lines crashing, that's a whole other issue. And I urge you to read the reports on the record. Because those reports show that the lines are overloaded. Every system crash that they have brought forward as a

reason for this line, the lines are grossly overloaded. Transmission load and relief procedures are used more frequently. The lines are being operated regularly at or beyond capacity. Curtailment orders are being ignored or challenged, and overloads and operating delay and reductions make the system vulnerable.

Now, this is nothing to do with systematic liciti, this has to do with the utility's desire to move the cheap power to where they can sell it for more money. That is not systematic liciti. That is not serving customers. That is serving corporate desire for profit.

An example, and this isn't something that, you know, I am fabricating out of my mind, this is something that is on the record. The MAPP did a study of the June 25th, 1998 outage. Minnesota Power submitted on the record a Nebraska Public Power District, I believe, PPDD report about it, they are really concerned. The industry is concerned. They said that there are real limits to transfer capability out of MAPP region, and those limits are interdependent. This event is an alarming representation of how the MAPP

regional interconnected system's being operated at or even beyond its capabilities. They are running the system to the max.

So then you might think, well, then if we build another line that will relieve some of that. But it won't. Minnesota Power, Stan Carlson, agreed on the record that if they do build that, well, the economics will take control here and, yes, that line will be utilized. Economically it makes sense. You have the capacity, you utilize the capacity. And those lines are going to be as overloaded as the King-Arpin line is right now, it will happen very quickly.

So what's happening is the utilities are operating the system beyond its limits, they're endangering the grid and reliability. Reliability is your concern, you need to ensure reliability, not exacerbate the problem. And these practices, whether intentional or to negligence, has extreme potential for human impact, because it can crash the grid, and even the industry is worried about this.

And then the phase angle. It's hard for us, those of us that have been involved in this

for a long time to say that without laughing, but there is a phase angle problem. But the problem is that that's not a valid rationale for a new bulk power transfer line, because there are things they can do that are cheap to fix this. They could use single flow re-closing, they could use the phase angle transfer on the other end of the line. They could use uniform power for a controller. They're not doing any of that. Instead they want a power line.

Also, there's no benefits to Minnesota in this line. They've testified it's flowing to -- it's not flowing to Minnesota, it's flowing to Wisconsin. So what's the benefit for Minnesota here? Where are the benefits for Minnesota ratepayers? Are they here? Do you see them? Where's the justification for this line? And, remember, we're supposed to be looking at the effects to Minnesota here. Our scope is limited. There's no benefit here for Minnesota.

So if they haven't done the reliability studies, they haven't made those simple fixes for the phase angle problem, Minnesota is not receiving any benefits, where's the justification for this line?

And the justification is they want a stronger position in this wholesale market. They want to be able to push more power through and sell their services that way. And that is not reliability.

The memo from Commissioner Studders is a good concept, it's really important that you're paying attention to MVA, the capacity moving through that line.

Now, a comparison, though, most people aren't familiar with those figures, what they mean. The King-Arpin line, that's rated at 700, that's 100 less. The King-Arpin line is a bulk power transfer. 800 is clearly bulk power transfer. And that's 100 more MVA than the King-Arpin line.

Now, the King-Arpin line, though, typically right now, and it's in the record, is running at often 1,000 to 1,100. They're running that way over. So what security will we have that this won't be running even further beyond that bulk power transfer that they're trying to accomplish now?

Another thing to look at, if you do exempt this, is that eminent domain provisions of

the PPSA do not apply. The PPSA gives homeowners broader -- broader rights and compensation, and you need to look at that. There are not that many homeowners, but there are some up in the midway area who may be affected by this, and you'll restrict their rights under eminent domain.

So Minnesota's promotion of the Arrowhead project, this is not necessary. It's not a solution and (inaudible) to assure reliability. So we ask that you deny this exemption. And, remember, this is not a denial of the project, it just means it would have to go through the Power Plant Siting Act.

And as you make your decision, it's important to remember, you're the decision-makers, you individually have had to look at the record. And the pure decision -- is that Mr. McGovern? I don't remember what your name was, I'm sorry. Yes, that other, that second one, is that out already?

UNIDENTIFIED: Yes.

MS. OVERLAND: Okay. The pure decision, I put this before you, it talks about the importance of individual decision-makers to read the record. That includes the transcripts, that

includes the reports of the system outages. You need to read the record yourself. Here it says the agency must review the evidence and findings amassed by a hearing examiner and come to an independent decision. Thus the legislature clearly intended agency members to read the material presented to them prior to reaching their decisions. What they want is to make sure that the officials themselves made the decision and not just rubber stamping findings. So, who among you has read the whole record of this proceeding?

UNIDENTIFIED: (Inaudible).

CHAIR HUGOSON: Ms. Overland, are you through? Any questions for Ms. Overland?

MR. CROCKER: Will you answer her question?

UNIDENTIFIED: (Inaudible) people read that record. Does anybody read --

CHAIR HUGOSON: Please. Any questions for Ms. Overland? Hearing none, thank you very much, we appreciate your testimony.

(Clapping.)

CHAIR HUGOSON: Ms. Hanson, I'm sorry, could I just ask you, where do you live?

MS. HANSON: I live in (inaudible).

CHAIR HUGOSON: Okay. Thank you very much. The next one that's up for testimony is Mr. George Crocker, representing the North American Water Office. Mr. Crocker, welcome to the Board.

MR. CROCKER: Thank you, Mr. Chairman, Members of the Board. My name is George Crocker, I am representing here today the North American Water Office, as well as the Clean Water Action Alliance, which was a formal intervenor in this proceeding. We consolidated our cases and I represented Clean Water in that proceeding. They are not here today to speak independently, I am speaking for them, and I do have a prepared message for you, Mr. Chairman.

CHAIR HUGOSON: Thank you. Please proceed.

MR. CROCKER: I speak from knowledge and experience gained over 25 years of representing with some success public interests in the electric energy decision-making. My job is to help decision-makers and the public understand how, for better or worse, energy development is connected to social justice, economic development, and our environment.

This decision takes place within a broader context of energy management in Minnesota. The glaring irony is that even as the complexity of the electric system is increasing dramatically, due to technology innovations and regulatory reform to bring more competition to energy markets, even as we are increasing dramatically the complexity of the system, this, the largest energy facility proposed in the region during the past 18 years at least, wants your approval with the limited review, narrow scope and reduced scrutiny of an exemption proceeding.

(Clapping.)

MR. CROCKER: But the complexity creates great potential for unintended consequences of improvident actions to unwittingly damage the system.

(End of Side A of Tape.)

(Side B of Tape.)

MR. CROCKER: Evidently detailed scrutiny is more for policy walks. When the time comes to decide what facilities will actually come online, MEQB can let the power companies eyeball it, and if they say it looks good, just do it. The irony of reduced scrutiny and narrow scope in

this proceeding has a more sinister dimension to it. It cuts at the core of our social fabric. It cuts at the contract which binds us together. Even as operating the interconnected grid knits our interests and concerns closer together throughout the entire region. This proceeding specifically prevents you, the decision-makers, from understanding interconnected regional interests and concerns and precludes a decision that accounts for them. That's what an exemption does.

For several years now, many people have attempted to call MEQB's attention to major deficiencies in the Power Plant Siting Act. Now, even as the crisis mounts throughout the land over how society will deliver electric utility services, vested interests are taking advantage of those deficiencies in the Power Plant Siting Act. Vested interests have manipulated Minnesota's Power Plant Siting Act so that knowledge you need to determine what, in this situation, will help resolve the crisis, and what will make it worse, is beyond your scope. So, we proceed in ignorance.

A process that allows a major facility

such as this one to proceed at this point in time on this basis is fatally broken. Understand that pushing forward with a fatally broken process is virtually guaranteed to produce much unwelcome excitement.

(Clapping.)

In this setting, just because the proposed facility qualified to apply for an exemption, doesn't mean the exemption should be granted. Just because the applicants put evidence in the record that got misconstrued into findings for an exemption, doesn't mean that public interest, which you are bound to uphold, will be served by granting that exemption. Quite the contrary. There is ample evidence on the record to reject this application to exempt obsolete and dirty technologies from scrutiny.

Two facts stand out. Neither is disputed. Each is sufficient to warrant denial of the exemption because each points to significant adverse human and environmental impacts in Minnesota. In a rational world each would compel you to do so.

Fact one. There is no reliability analysis of the project as proposed. Fact two.

If constructed, Arrowhead-Weston will be operated to achieve economic disadvantages.

Regarding fact one, no reliability analysis. The only reliability analysis related to the project was done in conjunction with the Wisconsin Reliability Assessment Organization, the WRAO report of June 1999. According to applicant witness, Carlson, who sits behind me, the WRAO report forms the foundation for the proposal, and he could identify nothing else that is part of that foundation. But the analysis reported by the WRAO was for plan 3j, which includes not just Arrowhead-Weston, but some 26 additional associated projects and upgrades and substation improvements.

How the system will perform in a variety of contingency situations with the Arrowhead-Weston line in isolation, and without the supporting improvement and upgrades of plan 3j, is not known. What is known is that the interconnected grid is an extremely complicated machine in which alterations to one part will cause changes, often unexpected changes, to other parts. Without analysis of Arrowhead-Weston as proposed, which has not been done, you as

regulators have no way of knowing what the impacts to the interconnected grid of Arrowhead-Weston operations will be. And by approving this exemption you will be saying just let the applicants eyeball it and we will believe whatever they say.

In the concluding paragraph of its executive summary, the WRAO, a foundation document for the application, states, and I quote, "In order to achieve the benefits which construction of plan 3j would provide, it must be constructed in its entirety. For all the plans presented, several significant additions or upgrades to the underlying transmission system are required. Notably, the Chisago-Apple River 230 kilovolt project presently under regulatory review in Wisconsin and Minnesota is considered a critical requirement for all of the plans, except plan 5a, Chicago-Weston, 345. Two of them. 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, Appleton-Weston, 230 kilovolt, as an alternative."

In other words, the foundation document for the application does not support this project. And as you know, Chisago-Apple River 230 will never be built.

If Arrowhead-Weston is built more people will be more dependent on more generation that is further away. Does that sound like more reliability to you? Creating such dependence inherently reduces reliability throughout the region, including Minnesota. But if Arrowhead-Weston does not result in unanticipated system disruptions due to unexpected loop flows and the like, Arrowhead-Weston would still only shift the weak link in the MAPP main interface, not remove it.

The case for the exemption rests heavily on specific events of June of '97 and June of '98, when storms and operator error caused grid problems. But for every instance cited to justify Arrowhead-Weston, an equally probable instance could disrupt the MAPP main interface at the Arrowhead-Weston with more drastic consequences because more people would be more dependent on distant generation. A storm would just have to course a little further east, that's all it will

take. Instead of King-Arpin being the weak link, the weak link shifts to Rocky Run-North Appleton, which before and after Arrowhead-Weston remains the single 345 kilovolt connection from the MAPP main interface into the eastern Wisconsin grid.

When Rocky Run-North Appleton goes down after Arrowhead-Weston is online, operators will still be in an emergency mode just as they are now when King-Arpin trips. Operators will still have less than one-half hour to re-close the line or shed load, which is no different from the present King-Arpin situation, except that more people will be affected.

In a rational world it would be recognized that these reliability uncertainties and implications will result in significant human and environmental impacts adverse to Minnesota. This recognition would prevent authorization of this exemption.

Regarding fact two, economic dispatch. Economic dispatch occurs because some power plants are more expensive to operate than others. It allows cheaper to operate plants to come online earlier in the dispatch order than more expensive ones. And there is no dispute that

Arrowhead-Weston will accommodate power transfers for economic dispatch purposes.

Now, I might also add that in the Wisconsin proceeding they make no bones about it. The ancillary benefit for this project, it is economic dispatch. In Minnesota it was a little more difficult to come to that understanding, but it's on the record.

Arrowhead-Weston will frequently give consumers in eastern Wisconsin access to power plants that are cheaper to operate than locally available plants. In the MAPP main region dispatching cheaper power plants earlier to serve eastern Wisconsin necessarily means, and can only mean, one thing. It means more generation from power plants whose pollution affects Minnesota. Dispatching capacity economically over the Arrowhead-Weston line necessarily means more mercury deposition in Minnesota. It necessarily means more particulate deposition in Minnesota, and more acid deposition in Minnesota. It can mean no other thing.

Just as power flows from the northwest to the southeast through the MAPP main region, it is simply not possible to economically dispatch

power through a 345 kilovolt power line from northern Minnesota, southeast into Wisconsin, without producing more pollution that impacts Minnesota. The applicants cannot have it both ways.

If there will be economic transfers, which is not disputed, there will be more pollution impacting Minnesota originating from the economically dispatched capacity. The record is loaded with evidence about how this increased pollution in Minnesota will result in significant Minnesota human and environmental impacts, and this evidence cannot be properly, rationally, or arbitrarily dismissed by the MEQB, and the exemption must therefore be denied.

In addition to these significant social, societal impacts, there will be significant individual impacts to those living along the 12-mile segment. People along that route will not settle and will try to sell their homes to get away from the power line. But even if those people get fair market value for their property, the impact on them will be significant. Purporting that those impacts are not significant, that that is not a significant human impact, is

like claiming that a paralyzed victim of a shooting is not significantly impacted if the victim is given enough compensation.

There will be significant impacts of this power line. A construction permit proceeding is required to determine if any benefits of the proposal may -- the proposal may provide are sufficient to offset those impacts from a public interest perspective.

In conclusion, there is a reason why the decision in this matter rests with you, the MEQB, and nowhere else. It is your job to apply the law to the facts in a manner that best serves Minnesota human and environmental resources.

As the preponderance of evidence on the record shows, and as I have discussed, granting this exemption would serve private corporate interests at the expense, perhaps the extreme expense, of Minnesota human and environmental resources.

You are here not to be window dressing, but to prevent serious mistakes such as this from happening. Because when serious mistakes are made there are serious consequences.

Thank you.

(Clapping.)

CHAIR HUGOSON: Any -- any questions for Mr. Crocker? Any questions for Mr. Crocker? Seeing none, thank you so much for your testimony.

Members, I know schedules are an issue for all of us. The kind of thing, I guess what I would propose, and we'll see what we -- and obviously we have to be concerned about having a quorum. We have a number of other people that have requested time to speak, and what I would propose is that -- I know all the people that are requesting time here are from Wisconsin, and I know you've got Minnesota's best interest at heart, but the issue that is before us is what goes on in Minnesota. And so it's a situation of as it relates to the scoping decision before this Board has to do with the Minnesota situation, looking at it from the human and environmental impacts to the state.

So I guess what I would propose is that I would randomly pick at least a couple of members that are still here, or that are here that would like to testify, but would, again, would ask that the comments would have to be addressed to this

issue that's before this Board. And that is as it has to do with what goes on in Minnesota. Knowing that, full well, that there's a process that's going on in Wisconsin independently from what's happening here.

So members, with your -- with your indulgence, I guess I would propose that we would take a couple of testifiers here, and then proceed from there.

Any -- any questions or any comments from Board Members?

UNIDENTIFIED: May I address the Board? Thank you. Under Minnesota Rules 4405.0600, any person has a right to provide their statement to the Board on an issue such as this one, and understanding the scope (inaudible) Minnesota, but without knowing any more (inaudible) presented, I believe that everyone here who wishes to speak does have that right to speak today.

CHAIR HUGOSON: I understand what you're saying, but also realize that it has to be what's on the record already that the testimony is addressing as well.

Counsel, do you care to respond? Mr. Wagenius.

MR. WAGENIUS: Mr. Chair, Members of the Board, the -- this is an on-the-record proceeding, and the record was closed, I don't remember the exact date, but at least a couple of weeks ago. Ms. McGillivray has pointed out a matter that is in the rules, and it is also the case that the Chair has a lot of discretion. And I think that this is an appropriate exercise of his discretion to limit the numbers of people. What he -- what the Chair has suggested is, it seems to me, an appropriate curtailment of the number of people that are allowed to speak, and I don't -- I don't see a problem with what the Chair has proposed. I think that you, Mr. Chair, left it to the Board Members to agree. Now, I don't remember exactly what you said, but it seems to me that the Chair does have this discretion.

MS. McGILLIVRAY: (Inaudible) I understand the discretion, and that this is such an important issue that I do know that there are many members of the public who wish to speak. Rather than taking it -- if the Board so chooses to limit testimony rather than taking it randomly, maybe just ask for volunteers. Then let those (inaudible) within the scope, of course, of the

relevance, and not any new testimony to this record, but allow the members of the public (inaudible) to speak to make that (inaudible). So...

CHAIR HUGOSON: Would the parties be amenable to choosing among yourselves two people to testify?

(Inaudible conversation.)

UNIDENTIFIED: Quite a discretion there.

CHAIR HUGOSON: If there are -- I'm offering this as a way to proceed.

Ms. McGillivray.

MS. McGILLIVRAY: Could we instead set a time limit at when you'd like to adjourn, and then everyone would have to accommodate the others, so that everyone would have an opportunity who wishes to speak? I'm just trying to allow everyone to leave here without feeling --

CHAIR HUGOSON: Part of my concern, Ms. McGillivray, is that, you know, what we're interested in is hearing facts that have not perhaps been raised. Already in the testimony that has been presented, we've had -- we've had information that has been repeated. And that's,

you know, that's within your --

(Inaudible conversation.)

MS. McGILLIVRAY: (Inaudible) I don't know what everyone here is going to testify to, so I wouldn't be able to make that statement to you. (Inaudible) appear as individuals, I'm just trying to make sure that everyone has -- is allowed an opportunity to speak.

(Inaudible conversation.)

CHAIR HUGOSON: Okay. I'm sorry. The evaluation, for the record, that needs to be made here.

Members, what's our time frame here? Ms. Engebretson.

MS. ENGEBRETSON: Mr. Chair, thank you. I'm just really curious, a show of hands, if I may ask for that, of those who live along that 12-mile stretch.

CHAIR HUGOSON: The Minnesota portion you're referring to?

MS. ENGEBRETSON: Yes. I'm wondering how many people actually are from that 12-mile stretch. Please raise your hand.

UNIDENTIFIED: Mr. Chairman, and Madam, I'd like to address that, if I could. I don't

believe --

MS. ENGEBRETSON: Well, it's up to the Chair.

CHAIR HUGOSON: Please.

UNIDENTIFIED: I don't believe that there's anyone here in the room that is from that line. I will say that I have contacted some of the 12 families that are adjacent to the line that would be extremely affected by this, and to a person, the ones that I talked to, were of the opinion that there was nothing they could do, that the decision had already been made by the Board, so what was the use of coming. They feel beaten down before it even started. (Inaudible).

CHAIR HUGOSON: Okay. Sir, please.

UNIDENTIFIED: (Inaudible) by the Board here.

CHAIR HUGOSON: What I'm going to do is I will allow another ten minutes for testimony from people that wish to -- wish to speak. The power company had ten minutes that they presented, we've had three other groups that, you know, in opposition that have had their ten minutes, and at least one of them went over by some time, which is -- I did not question, and so if you want to

proceed with taking another ten minutes, we will do that.

UNIDENTIFIED: (Inaudible).

CHAIR HUGOSON: Please. Come forward and identify yourself for the tape, please.

MR. KREGER: My name is Tom Kreger (phonetic), and I'm from Mazomanie, Wisconsin, and thank you for your time today.

Just a couple of points that I think you people really need to think about here. From, again, the reliability aspect of it. The primary witness from the utilities was Dan Carlson, who tried to make the case for need for the line. This same gentleman, under oath, was unable to explain a loss of load expectation table from the WRAO report, which is the primary piece of documentation that they used to justify this line again.

The WRAO report, which is part of this particular case, which is the basis for it. If you look in the WRAO report, the primary purpose of that report was to find ways to import power into eastern Wisconsin. Importing power into eastern Wisconsin means it's coming out of Minnesota.

Minnesota seems to realize that they're going to have their own generation shortfall in the near-term future here. Do you really want to be sending electricity that's available for Minnesota's needs to Wisconsin, primarily to satisfy the whims of two utilities? You're supposed to be taking care of the priorities of Minnesota.

And ultimately they're asking Minnesota ratepayers to pay for something that's actually not going to be beneficial to them. Again, you're taking something that would be there for their use, a commodity such as electricity, and you're making that unavailable by selling it to the highest bidder, which is Wisconsin in this case.

Without an in-depth look of alternatives to the line, as Mr. Crocker said, you may be doing a lot more damage by granting this exemption permit than you may be doing good. Thank you.

CHAIR HUGOSON: Thank you very much. Any questions? Thank you very much, Mr. Kreger.

MS. SEALER: My name in Linda Sealer (phonetic). I just sat through the last two months of hearings in Wisconsin as a full party representing Gerald and Lynn Sealer, who are the

owners of Hillside Dairy located in (inaudible), Wisconsin. Just a couple points that I wanted to make.

One of them is in regards to Mrs. Studders' letter that she gave to the Board today. She talks about the potential for this line being a bulk transfer line. I think you all need to consider that plan 3j, if routed through the (inaudible) area in the state of Wisconsin will provide no local load serving. Looking at that regard, there is nothing it can be other than a bulk transmission line.

I did attend the prehearings in Minnesota in regards to this, was not a full party in Minnesota; however, a lot of what was stated at those prehearings, in regards to limiting the scope especially, would be that the environmental concerns would be looked at within the state of Wisconsin. There have been no briefs filed, I don't know if anybody has read the 10,000 pages of transcripts involved in that proceeding, I don't know if you're aware of the opposition in which 1200 landowners came out to speak against this line at the various hearings held out throughout the state. However, there is a lot of information

in there in regards to the environment.

Again, I would also listen to your stating of the laws, in which I believe that you stated if this line was over 25 miles you would be duty bound to consider going through the full Power Plant Siting Act. It is mentioned in the application, and it has been mentioned repeatedly in the testimony in Wisconsin, that Minnesota Power will provide the construction for 120 miles of the line within Wisconsin, roughly between Oliver and Ladysmith, Wisconsin. Fortunately for Minnesota Power, the state line stops so that they're only at 12 miles. I urge you to look into that consideration. Thank you very much.

CHAIR HUGOSON: Thank you, Ms. Sealer.

MR. EDDINGER: My name is Logan Eddinger (phonetic), I'm from Harmon, Wisconsin. Before you rule on this there's a couple things I want you all to consider. Please consider the people directly affected by this line. Some people have worked their entire lives and their careers for their house and their little plot of land. If you grant this application you will be allowing the already immensely rich private company to destroy their lives and destroy their dreams.

Speaking for myself, I will hold each and every one of you responsible for your decision.

Please consider the injustice of eminent domain. This project is not for the greater good of the people of Minnesota, this is purely a financial strategy project for an already rich company. They want to supply the electricity to the mining district of northern Wisconsin.

Think of the health issues involved with this. Energy providers have long since denied the existence of stray voltage. This is no longer the case. Xcel Energy has asked that a bill be inserted in the Wisconsin state budget bill to protect them from liability from stray voltage issues. We finally have a major electrical provider admitting that stray voltage exists.

I ask that the Board consider that, all these things.

CHAIR HUGOSON: Okay. Thank you, Mr. Eddinger. Sir? If you'd identify yourself for the tape, please.

MR. THOMAS: Thank you for the opportunity to appear. My name is David Thomas, I live in Poplar, Wisconsin, and though I'm not a

Minnesota resident, I'm just a few miles from the border and I do spend a good deal of time in the Duluth area, including the Minnesota side.

In the interest of time here, I wanted to address something that a staff member had said in encouraging you to support this exemption. And he said, of the health issues, all they are is assumptions.

On March 4th I was returning from a vacation in Europe. As I passed through Zurich, Switzerland I was handed a copy of the New York -- or the Sunday London Times by the flight attendant to read on the plane. The headline on that paper that day was Conclusive Evidence, Pylons, high voltage transmission lines is the British term for that, Pylons Cause Cancer. In the article they state, after extensive testing that they've found, the most distinguished engineers, electrical engineers in Britain have found that it increases cancer, childhood leukemia, by over 100 percent.

We're talking about significant human impact in Minnesota. I think that is enough, with 10 houses in 10 miles -- 10 houses that are within a few hundred feet of that line. That is something to consider.

The other comment I have is that -- that the two power companies requesting this, to build this line and requesting this exemption, have at their disposal billions of dollars, billions, tens of billions of dollars, in assets. We are holding raffles, bake sales, and every other thing to try and fight this for our lives and for our communities. And I want you to take that into consideration too. We're the small guy, we're trying to fight Goliath, and we believe we have a strong case.

Is this exemption equal to a loophole for them? I believe that they should have to follow, we're asking simply that they follow and complete the application with the environmental impact statement, so that you folks can make your decision based on that. We're asking them just to complete the permit. They have plenty of money at their disposal to do that. Thank you for your time.

CHAIR HUGOSON: Thank you, Mr. Thomas.

(Clapping.)

CHAIR HUGOSON: Take one more, please.

MR. STEFFEN: My name is Roger Steffen, I'm also a resident of northern Wisconsin, but

I've spent a tremendous amount of time in this state. I love this state, the northern part especially, and I love Wisconsin also. I don't see boundaries. I don't see a boundary between these states. The environment has no boundary.

Wisconsin just came out with mercury warnings, do not eat fish lists on all their waters. I think Minnesota will probably follow, unless they want to attract the fishing crowd from Wisconsin over here, but I hope not.

What we're doing is speeding down a road, a very dangerous road, at breakneck speed. When things are changing in the environment -- I guess I'll just throw something real quickly out here. I spent 30 years as an energy engineer, I spent a lot of time over here, with the utilities over here, I know a little bit about what I -- what I talk about. And you have a rare opportunity, a rare opportunity to change the direction of energy use. We're here today because Wisconsin has no energy policy, at least no succinct or distinct or even remote energy policy. You folks I think are going to be formulating one here. Be careful.

We're on collision courses with

population growth, with per capita energy use. That's a collision course. And it's a collision course with energy supplies. It's not a -- I mean, we've got a finite supply of energy. When you look at what's happening in terms of use in a finite supply, we're headed down a road that could lead us to disaster, as George Crocker said so eloquently.

So, I plead with the Board, consider changing the direction. We don't want to slay Goliath back here, we just want to change the way he thinks.

And thank you.

CHAIR HUGOSON: Okay. Thank you, Mr. Steffen. Any further questions?

(Clapping.)

UNIDENTIFIED: One more.

CHAIR HUGOSON: I'm sorry --

UNIDENTIFIED: One more.

CHAIR HUGOSON: I said for ten minutes --

UNIDENTIFIED: I have personal information from one of these people that you might want to hear that's on this line who couldn't come today because he is an emergency

nurse who works in a hospital --

CHAIR HUGOSON: I'm sorry, sir, but if I take you, then --

UNIDENTIFIED: Very significant human health issues that are not being addressed by your Board on this, and I think you could find those human health issues, just as you took yourself, if you put yourself under this line.

Mr. (inaudible), who loves northern Minnesota, we --

CHAIR HUGOSON: Sir.

UNIDENTIFIED: We love our area. Could you imagine if this was built over your dream house? Would it have significance --

CHAIR HUGOSON: Sir, would you please sit down?

UNIDENTIFIED: -- your lifetime.

UNIDENTIFIED: Let him talk.

UNIDENTIFIED: Let him talk.

CHAIR HUGOSON: He has talked. Thank you.

UNIDENTIFIED: Thank you. I also want to thank Minnesota for being so generous to send your electricity that you're going to be short to southern Wisconsin and the Chicago area.

UNIDENTIFIED: You bastards.

CHAIR HUGOSON: Board Members --

(Clapping.)

CHAIR HUGOSON: -- you have a resolution before you, any further discussion?

MR. TINKLENBERG: Mr. Chair.

CHAIR HUGOSON: Mr. Tinklenberg.

MR. TINKLENBERG: I just have a question about condition number 10. I understand the rationale behind it, the motivation behind it, I'm wondering what the basis for it is in rule and what the procedures are that will be followed in reviewing that, or what will be the consequence of that?

CHAIR HUGOSON: Okay. Mr. Sullivan.

MR. SULLIVAN: Let me take a shot at it, and if I don't do the job we'll let counsel deal with it.

Under a normal permit issued by the Board, you set the parameters of what the project is, how you operate it, what levels, what the equipment looks like, whether it's a substation transmission line or power plant. And in this particular case you have the authority to condition the granting of this exemption.

In this particular case, you know, this is suggested, because this issue of how much power can you move through this thing once it's built is out there, Commissioner Studders has raised this, it's been raised on the record, (inaudible). When a permit would be issued, if someone were going to change those parameters, they would have to come back to the Board and get what we call a minor alteration, approval of a minor alteration that they could apply for.

My understanding of this language is given the utility's representation that they will use this facility at a certain level, what this does in this case is that basically puts a condition in that says that if you're going to change those parameters of operation, I think the implication here, the concern is push more power through the facility than the transformers apparently are presently designed to handle, that they would have to come back and advise this Board of that and they would have to approve.

MR. TINKLENBERG: What would be -- what would be required in that? Is there a public hearing process? I mean, on what -- what would that entail in terms of that review? What would

go into that review of the impact of that? I'm trying to understand what would trigger that, an approval or denial of that?

UNIDENTIFIED: (Inaudible).

CHAIR HUGOSON: Mr. Mitchell, if you would, please.

MR. MITCHELL: Mr. Chair, Members of the Board, the Power Plant Siting Act sets forth the jurisdiction of the Board over high voltage transmission lines, over large energy generating plants. We think that even without this condition, if they want to change that, they'll fall within the jurisdiction of the EQB. Because this is a 345, and if they want to go larger they would have to come to the Minnesota Environmental Quality Board for approval for that.

The statutory language includes not only the line or the plant, but also associated facilities. That's how we bring the substation in with the line. We made a reference to 116C.57, which is the power plant siting route permit language. Right now there's two procedures. You get the full permit or you get the exemption. And that's what the issue is here today. Are we going the full route or are we going with the

exemption? If the law remains the same in the future, and Minnesota Power wants to expand, well, they would have the option of asking for another exemption or getting a site permit.

There are provisions in the bills floating around the legislature to eliminate the exemption provision. So if the law changed, well, then, that's what would apply in the future.

MR. TINKLENBERG: All right.

CHAIR HUGOSON: Okay. Any other discussion? Yes, Mr. Kaden.

MR. KADEN: I have a question for counsel. Ms. Overland stated earlier something about if the -- if the EIS process did in fact have to be followed, that the landowners could possibly get more compensation under eminent domain, is there anything to that?

CHAIR HUGOSON: Mr. Wagenius, do you feel -- do you feel that you can answer that, or is there someone else we need to --

MR. WAGENIUS: Sure.

UNIDENTIFIED: (Inaudible).

CHAIR HUGOSON: Please, please, please.

UNIDENTIFIED: He's referring to her statement. She can answer it.

CHAIR HUGOSON: We could terminate this real -- I'm sorry. Mr. Wagenius.

MR. WAGENIUS: Mr. Chair, Member Kaden, the -- the eminent domain authorities exist separate from this statute. That there's a reference in 116C.63, which -- subdivision one, which leads off with nothing in this section shall invalidate the right of eminent domain vested in utilities by statute or common law, except to the extent modified herein. And the modification is a procedural modification. So, this reference to eminent domain law is really outside the jurisdiction of the agency. I mean, eminent domain is this whole separate body of law. So the statement that Ms. Overland made about any change in compensation is something that's beyond what this Board deals with, it's also beyond my experience.

UNIDENTIFIED: May I approach the Board, please? (Inaudible) to take an entire fee interest, not just a small easement. Thank you.

CHAIR HUGOSON: Any other discussion? Hearing -- Ms. Engebretson.

MS. ENGEBRETSON: I'm just going to ask a question. To deny this would mean that they

would go for a full permit with an EIS?

CHAIR HUGOSON: The full routing process.

MR. SULLIVAN: Mr. Chairman.

CHAIR HUGOSON: Mr. Sullivan.

MR. SULLIVAN: Mr. Chairman, Members of the Board, if the exemption is not granted, if this project were to be built, the utility would have to come back to this Board and apply under the full power plant siting, routing, in this case, process.

CHAIR HUGOSON: Mr. Wagenius.

MR. WAGENIUS: Mr. Chair, Mr. Sullivan, Member Engebretson. The statute actually goes beyond that. It says that if you deny an exemption, you have to state the reasons why you're denying it, and the changed circumstances that would allow you to grant an exemption, and then the applicant has a choice -- well, actually, three choices. They can abandon it, or they can come back for a separate exemption based upon a revised case, taking into consideration what the Board has told them in their decision denying the exemption, or as a third option, they can come back under the full routing process.

CHAIR HUGOSON: Okay. Thank you. Does that -- any further discussion?

UNIDENTIFIED: Mr. Chairman.

CHAIR HUGOSON: Mr. Cole.

MR. COLE: My question falls along the statement that our counsel just gave us. Is there -- do we have anything of substance that we could put our hands on, figures, facts, that would provide substantially a denial?

(Inaudible conversation.)

CHAIR HUGOSON: Mr. Mitchell.

MR. MITCHELL: Mr. Chair, Members. Well, you'd have to make findings contrary to what the Administrative Law Judge found and what the staff is recommending, and you would have to find that this line does -- or this line may create significant impacts on human health or the environment.

UNIDENTIFIED: I read this document and I don't have enough facts to say that we could deny at this point in time. I've heard a lot of testimony, but to say that there's Findings of Fact, I know there's some conjecture on both sides, I'm sure of that too. I just wanted to ask that question, if anybody else had more than I

had.

CHAIR HUGOSON: Thank you. Any other discussion? Hearing none, I'd ask Mr. -- I'm sorry. Counsel.

(Inaudible conversation.)

CHAIR HUGOSON: Okay. Good point. Just to make sure that everyone is sure what we're voting on, we're voting on the resolution, as it's written, as amended, and with the incorporation that was included with the Studders' proposal as well.

Mr. Sullivan, take the roll, please.

MR. SULLIVAN: (Inaudible).

UNIDENTIFIED: Yes.

MR. SULLIVAN: Enzler.

UNIDENTIFIED: (Inaudible).

MR. SULLIVAN: Enzler.

MS. ENZLER: Yes.

MR. SULLIVAN: Kaden.

MR. KADEN: Yes.

MR. SULLIVAN: Maline.

MR. MALINE: Yes.

MR. SULLIVAN: Barkley.

MR. BARKLEY: Yes.

MR. SULLIVAN: Tinklenberg.

MR. TINKLENBERG: Yes.

MR. SULLIVAN: Fields.

MR. FIELDS: Yes.

MR. SULLIVAN: Engebretson.

MS. ENGEBRETSON: Yes.

MR. SULLIVAN: Chair.

CHAIR HUGOSON: Yes.

There being nine ayes, no nays, the resolution is adopted.

UNIDENTIFIED: The bomb could be instead in Minnesota.

CHAIR HUGOSON: Any further --

UNIDENTIFIED: The bomb could be instead in Minnesota.

CHAIR HUGOSON: -- business for the Board? The meeting is adjourned.

UNIDENTIFIED: We'll see you on the picket line.

(Tape concluded.)

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

REPORTER'S CERTIFICATE

I, Janet Shaddix Elling, do hereby certify that the above and foregoing transcript, consisting of the preceding 87 pages, is a full, true and complete transcription of the tape recording of the proceedings, to the best of my ability.

Dated April 18, 2001.

JANET SHADDIX ELLING
Registered Professional Reporter

SF-00006-05(4/86)

DEPARTMENT: POLLUTION CONTROL AGENCY

STATE OF MINNESOTA

Office Memorandum

DATE: March 13, 2001

TO: Commissioner Gene Hugoson
Chair, Environmental Quality Board

FROM: Commissioner Karen Studders
Pollution Control Agency

PHONE: (651) 296-7301

SUBJECT: Arrowhead – Exemption Application

I cannot attend the Environmental Quality Board (EQB) meeting on March 15, 2001, because I will be in Washington D.C. attending Great Lakes Day and meeting with congressional delegates. However, I have been following the Arrowhead exemption case quite closely and would like to express concerns that I have regarding this decision.

Attached to this memorandum is a letter written by Cynthia Kahrmann, of my staff, to Judge Nickolai during the public comment period. It expresses my staff's concerns regarding the potential use of this line for increasing bulk sales of electricity. In this letter, it states that if Minnesota Power cannot assure the EQB that this line will be used for reliability of the current supply of electricity only, then the project may not be suitable for exemption from the Power Plant Siting Act.

After reviewing the record for the exemption application, it is unclear to me whether this question was answered. It does appear that transformers that transform the power flow for the 230 kilovolt portion of the Arrowhead Substation into the Arrowhead 345 kilovolt transmission line would be designed to limit the line's capacity to 800 megawatts (see cross-examination of Dan Carlson by Michael Michaud, pp. 1873-1875, evidentiary hearing transcript). If this transformer indeed limits the capacity of the line to the current supply of electricity, I request that, if the exemption is granted, the following language be included as a condition of the exemption.

> Minnesota Power shall limit the 345 kilovolt transmission line's capacity to 800 megawatts. This shall be accomplished by installing a transformer that transforms the power flow from the 230 kilovolt portion of the Arrowhead Substation into the 345 kilovolt portion of the substation. Minnesota Power shall apply to the Environmental Quality Board for approval of any increase in capacity of the 345 kilovolt transmission line above 800 megawatts.

I understand that this may already be required under EQB rules; however, I think it is important to state it explicitly as a condition of the exemption.

This is an important condition because this was a major concern of Minnesota Pollution Control Agency staff and the intervening parties involved in this proceeding. Adding to the argument for this condition is my concern that Minnesota will not have input if power plants located outside Minnesota increase their generation. On page four of the Staff Memorandum included in our Board packets, EQB staff discuss the concerns brought up in the record regarding increased air pollution from electricity generation. In the second paragraph, it states that agencies with air permitting authority will address future increases in air pollution should an owner of an existing power plant seek to increase operation beyond current permitted levels or build a new power plant. This statement is true only if that plant is located in Minnesota. Minnesota permitting agencies have no authority in other states or countries, yet we are effected by the pollution these plants would create. For example, in the exception briefs, intervening parties mention the possibility of Great River Energy building a 500 MW plant in North Dakota. I have been asked by parties involved in this potential project to attend a meeting to discuss this future power generation and the potential impacts to Minnesota.

In summary, I send my regrets in not being able to attend this important meeting. If an exemption is granted, please consider my remarks in setting conditions.

KAS:mbo

Attachment

Exhibit, Comments, MPCA, September 15, 200

Minnesota Pollution Control Agency

September 13, 2000

Chief Judge Kenneth Nickolai
Office of Administrative Hearings
100 Washington Avenue South
Minneapolis, MN 55401

Re: Arrowhead – Weston High Voltage Transmission Line

Dear Judge Nickolai:

The Minnesota Pollution Control Agency (MPCA) respectfully submits the following comments regarding the Arrowhead – Weston High Voltage Transmission Line.

The MPCA staff has concerns regarding the role the proposed Arrowhead-Weston line could play in the possible future expansion of electrical generation capacity. We understand from the information in the record, prior to the evidentiary and public hearings, that there are no current plans to use this line to transmit future electrical generation to Wisconsin and beyond. However, MPCA staff is concerned that once the line is constructed, the line is available for anyone to use, and that shipping new bulk electricity will eventually occur. If an expansion of an existing power plant or the construction of a new power plant is permitted outside of Minnesota that will transmit electricity through this line, then the MPCA will not have authority to address environmental concerns for Minnesota, such as additional mercury deposition and the increase of greenhouse gases. The only opportunity the state may have to address these issues lies in the decision about future transmission capacity.

In its exemption application pursuant to the Power Plant Siting Act, Minnesota Power states that the purpose of the line is for reliability purposes only. To understand this concept, the MPCA requests that Minnesota Power state how it is technically feasible to distinguish between the use of this line for reliability versus the use of this line for increasing bulk sales of electricity. If Minnesota Power cannot assure the Environmental Quality Board that this line will be used for reliability of the current supply of electricity only, then the project may not be suitable for exemption from the Power Plant Siting Act.

Please call me at 651/297-8493 if you have any questions regarding these comments.

Sincerely,

Cynthia Kahrmann

Cynthia L. Kahrmann
Pollution Control Program Administrator Trainee
Policy and Planning Division

CLK:cmbg

Arrowhead HVTL
New Finding and New Condition
March 15, 2001

Amended Finding No. 11

1. The second bullet of Finding No. 11 is amended to read and a new footnote 18A is added to read:

Adding four single-phase 345/230 kilovolt transformers to interface with the 345 kV line. These transformers step up the voltage from 230 kV to 345 kV. The approximate rating of these transformers is 800 MVA. [18A]

18A. Transcript at 1874.

Condition No. 10

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.

Ex. JJ, Comment, WPCA, September 13, 20

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX K

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

ANNUAL ELECTRIC UTILITY FORECAST REPORTS

Appendix K

Forecast Information from Minnesota Power and American Transmission Company LLC

Pursuant to Minn. R. 7849.0270, subp. 1 and Minn. R. 7849.0270, subp. 2(A)-2(D), a Certificate of Need application must provide information related to peak demand and annual consumption data for an applicant's entire service territory and system. Minnesota Power and American Transmission Company LLC by and through its corporate manager ATC Management Inc. ("ATC") requested and were granted an exemption from this rule requirement by the Minnesota Public Utilities Commission.[1] In lieu of the information required by Minn. R. 7849.0270, Minnesota Power and ATC agreed to provide substitute data in the form of forecast information from Minnesota Power's most recent Annual Electric Utility Forecast Report ("AFR"), ATC's 10-year forecast, and any forecast information used by the Applicants or MISO in analyzing the need for the Project.[2]

Minnesota Power filed its 2025 AFR with the Commission on August 1, 2025, in Docket No. E999/PR-25-11. A copy of Minnesota Power's 2025 AFR filing and the substitute forecast information developed by ATC are provided in this appendix. Other forecast information used by the Applicants or MISO in analyzing the need for the Project is discussed in Chapter 3 of the Application.

[1] *In re Application for a Certificate of Need for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line*, Docket No. E015/CN-25-111, ORDER APPROVING NOTICE PLAN AND GRANTING EXEMPTIONS (Nov. 18, 2025).

[2] *In re Application for a Certificate of Need for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line*, Docket No. E015/CN-25-111, REQUEST FOR EXEMPTION FROM CERTAIN CERTIFICATE OF NEED APPLICATION CONTENT REQUIREMENTS (Aug. 7, 2025).

ATC's 10-Year Electric Load Forecast

Forecast Year	Annual Peak Demand (MW)	2024-2034 Compounded Annual Growth Rate
2024 Actual	12,744	-
2034	15,990	2.3%

Additional information is available on ATC's 10-Year Assessment website: https://www.atc10yearplan.com/2024/about/planning-methodology-and-assumptions/.

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

August 1, 2025

VIA E-FILING
Ms. Anne Sell
Department of Commerce – Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN 55101-2198

Re: Minnesota Power's 2025 Annual Electric Utility Forecast Report
Docket No. E-999/PR-25-11
ANNUAL COMPLIANCE FILING

Dear Ms. Sell:

Enclosed please find Minnesota Power's 2025 Annual Electric Utility Forecast Report pursuant to Minn. Stat. § 216C.17, subd. 2 and Minn. Rules Chapter 7610. As an electric utility with Minnesota service areas, Minnesota Power (or the "Company") is required to submit to the Minnesota Department of Commerce – Division of Energy Resources ("Department") by July 1 of each year an annual report specifying its short- and long-term energy demand forecasts and the facilities necessary to meet the demand. On June 3, 2025, the Company requested a one-month extension on its Annual Electric Utility Forecast Report which is now due August 1, 2025.

Information included in the "**ELEC_68_2024 Largest Customer List.xlsx**" and "**ELEC_68_2024 Forecast Report.xlsx**" Excel workbooks, as well as in the **Methodology** document, has been designated as **TRADE SECRET**.

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding Minnesota Power's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as Trade Secret in individual filings before the Minnesota Public Utilities Commission. Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

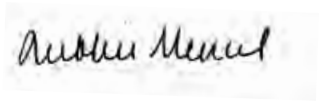
Minnesota Power is providing this justification for the information excised from the attached report and why the information should remain trade secret under Minn. Stat. 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the Trade Secret designation provided herein.

The following documents have been uploaded to the Department and Minnesota Public Utilities Commission eDockets/eFiling system using Docket Number 25-11:

- ELEC_68_2024 Annual Report.xlsx
- ELEC_68_2024 Forecast Report.xlsx (**TRADE SECRET** & Public versions)
- ELEC_68_2024 Largest Customer List.xlsx (**TRADE SECRET**)
- ELEC_68_2024 Monthly Power Cost Adjustments.xlsx
- ELEC_68_2024 MN Service Area Map.pdf
- ELEC_68_2024 USDOE EIA-861.pdf
- ELEC_68_2024 Rate Schedules.pdf
- METHOD24.pdf (**TRADE SECRET** & Public versions)

Please don't hesitate to contact me if you need additional paper copies or have any questions.

Sincerely,



Debbie A. Mencel
Regulatory Compliance Specialist
Minnesota Power
218-355-3182
dmencel@mnpower.com

DAM:amh
Attach.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2025 Annual Electric Utility Forecast Report	Docket No. E-999/PR-25-11

INTRODUCTION

The utility customer load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of energy consumption and seasonal peak demand requirements. Minnesota Power's forecast process combines a sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power (or "the Company") is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2025 forecast methodology document demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, completion of systematic and replicable processes, and thorough analysis of results.

The 2025 AFR forecasts a total of 9.2M MWh of energy sales in 2025, increasing by approximately 17.4% to 10.8M MWh of energy sales in 2039. The system peak forecast, by 2039, is 1,826 MW (winter), representing an increase of approximately 13.6% from Minnesota Power's actual system peak of 1,607 MW in 2024 with all current mining and metals customers operating.

Additionally, as national and regional trends continue to identify a new landscape for energy demand, along with Minnesota Power having ~7400 MW of industrial interconnection requests in the queue the Company included in this year's submittal, a Load Growth Forecast Planning Scenario (Section VI). This scenario is tied to the +1,100 growth case in Minnesota Power's 2025 Integrated Resource Plan ("IRP")[1] and is a conservative scenario given the potential. The Company also included a load down scenario (Section VII) to capture the complexities and volatility of industrial mining growth outlooks. These are important components to monitor for the utility as it continues to prepare for the electric needs of its service area.

[1] Docket No. 015-RP-25-127

Contents

I. Forecast Methodology 4

A. Overall Framework (7610.0320, Subp. 1.A) 4

B. Specific Analytical Techniques (7610.0320, Subp. 1.B) and Relation to Forecast (7610.0320, Subp. 1.C) 5

C. Statistical Techniques, Typical Computations Specifying Variables and Data, and the Results of Appropriate Statistical Tests (7610.0320, Subp. 1.D) 7

D. Forecast Confidence and Historical Accuracy (7610.0320, Subp. 1.E and Subp. 1.F) 24

E. Methodology Strengths and Weaknesses and Suitability to the System (7610.0320, Subp. 1.F) 25

F. Data Requirements (7610.0320, Subp. 1.F) 26

II. Forecast Data Inputs & Adjustments 27

A. Forecast Database Inputs (7610.0320, Subp. 2.A) 27

B. Forecast Adjustments (7610.0320, Subp. 2.B) 30

1. Adjustments to Raw Energy Use and Customer Count Data 30

2. Adjustments to Econometric Forecast 32

III. Overview of Key Assumptions (7610.0320, Subp. 3) 35

A. National Economic Assumptions 35

B. Regional Economic Assumptions 35

IV. Subject of Assumption (7610.0320, Subp. 4) 36

V. Coordination of Forecasts with Other Systems (7610.0320, Subp.5) 38

VI. Load Growth Forecast Planning Scenario 38

VII. Load Reduction Forecast Planning Scenario 42

Table of Figures

Figure 1: Minnesota Power's Forecast Process 4
Figure 2: Residential Customer Count – Expected Scenario 8
Figure 3: Commercial Customer Count – Expected Scenario 9
Figure 4: Industrial Customer Count – Expected Scenario 10
Figure 5: Public Authorities Customer Count – Expected Scenario 11
Figure 6: Street Lighting Customer Count – Expected Scenario 12
Figure 7: Residential Energy Use – Expected Scenario 13
Figure 8: Commercial Energy Use – Expected Scenario 14
Figure 9: Mining and Metals Energy Use – Expected Scenario 15
Figure 10: Paper and Pulp Products Energy Use – Expected Scenario 16
Figure 11: Other Industrial Energy Use – Expected Scenario 17
Figure 12: Pipelines Energy Use – Expected Scenario 17
Figure 13: Foundries Energy Use – Expected Scenario 18
Figure 14: Food Products Energy Use – Expected Scenario 18
Figure 15: Other Industrial Remaining Energy Use – Expected Scenario 19
Figure 16: Public Authorities Energy Use – Expected Scenario 20
Figure 17: Street Lighting Energy Use – Expected Scenario 21
Figure 18: Resale Energy Use – Expected Scenario 22
Figure 19: System Peak Demand – Expected Scenario 23
Figure 20: AFR Forecast Accuracy – Aggregate System Energy 24
Figure 21: AFR Forecast Accuracy – Summer Peak 25
Figure 22: AFR Forecast Accuracy – Winter Peak 25
Figure 23 Total Energy Sales for Load Growth Forecast Planning Scenario 40
Figure 24 Peak Forecast (MW) for the Load Growth Forecast Planning Scenario 41
Figure 25 Total Energy Sales for Load Reduction Forecast Planning Scenario 43
Figure 26 Peak Forecast (MW) for the Load Reduction Forecast Planning Scenario 44

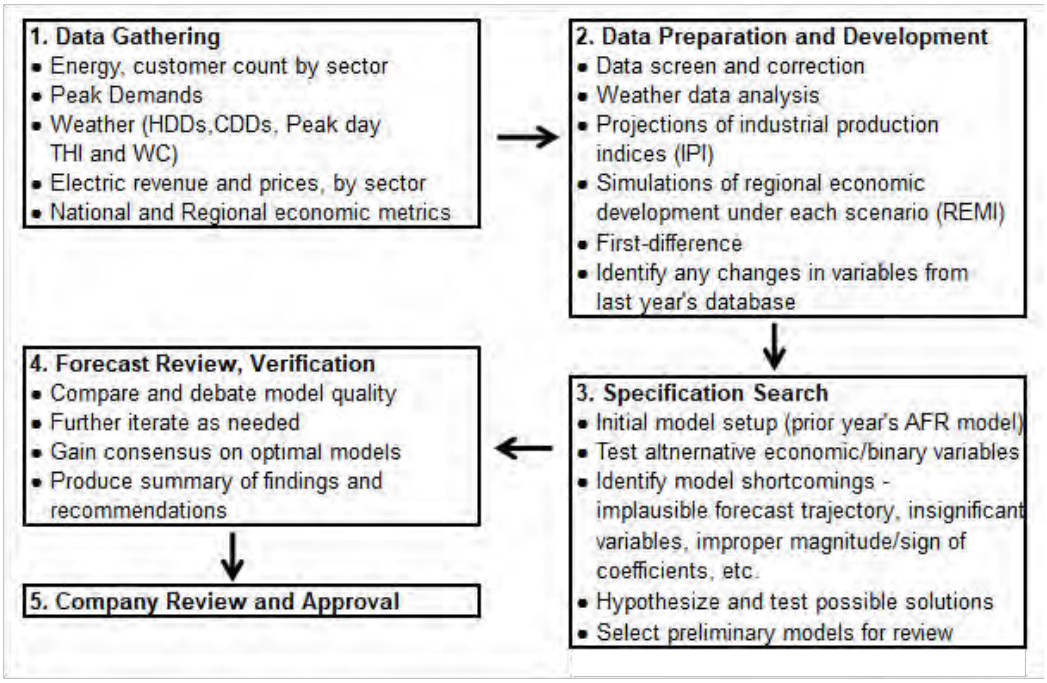
I. Forecast Methodology

A. Overall Framework (7610.0320, Subp. 1.A)

Minnesota Power's forecast models are the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50"; given the inputs, there is a 50 percent probability that a realized actual will be less than forecast and a 50 percent probability that the realized actual will be more than forecast.

The Minnesota Power forecast process involves several interrelated steps: 1) data gathering, 2) data preparation and development, 3) specification search, 4) initial review and verification, and 5) internal company review and approval. The steps of the forecast process are sequential, and the process is diagrammed in Figure 1 below.

Figure 1: Minnesota Power's Forecast Process



B. Specific Analytical Techniques (7610.0320, Subp. 1.B) and Relation to Forecast (7610.0320, Subp. 1.C)

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency of definition in a variable series and identify different potential relationships between predictor variables and the dependent variable. Minnesota Power uses the following data transformations in data development:

- *Constant-dollar Deflating/Inflating* – is the process of deflating/inflating all dollar-denominated series to the same base year to maintain consistency of definition. Minnesota Power utilized 2017 as its base year in AFR 2025. The 2017 base year is the current standard among public and private data providers such as IHS Global Insight and the Bureau of Economic Analysis ("BEA").
- *Per-day Conversion* – divides monthly billed energy use or monthly Heating/Cooling Degree Days by the number of days in the specified month. This transformation normalizes for the effect of varying days-per-month on a monthly aggregate like energy use or Heating/Cooling Degree Days. This results in consistently defined series that are more appropriate for linear regression modeling.
- *De-trend and De-seasonalize* – is the process of removing the historical trend/seasonality from a data series. This reduces the potential for the spurious, or *false,* correlation that often results from mistaking similarity of *trends* with similarity of *variation* between a predictor and the dependent variable (peak demand).
- *First Difference* – changes the definition of the series from *level* (e.g., the number of customers in a month) to *change* (e.g., the customers gained or lost from one month to the next) by subtracting the previous value from the current. The *first difference* transformation reduces the series to only *variation* (change) so there is no potential to mistake similarity of *trend* with similarity of *variation*.
- *Exponential* – is the application of an exponent to the series; either squaring or cubing the series. This transformation of raw data was only applied to the temperature variables in the Peak Demand model so the non-linear relationship of load to temperature could be more accurately quantified.

Interpolation Technique – Minnesota Power collects and utilizes raw monthly-frequency data whenever possible. However, some data series are not available at a monthly frequency (e.g., U.S. Gross Domestic Product ("GDP") is only available in quarterly and annual frequencies).

Interpolation allows annual or quarterly data to be used in monthly-frequency regression modeling by converting it to a monthly variable.

The specific interpolation function utilized in Minnesota Power's forecast process is known as a "Cubic Spline" interpolation. This technique is widely used because it produces a smooth monthly series by constraining the first and second derivatives of the variable to be continuous on the entire time interval.

Modeling Techniques – Most of the dependent count and energy variables are modeled using a trend variable to explain general, underlying growth and one or two economic/demographic variables to explain any economically-driven divergence from this trend. This approach to regression modeling reduces the potential for an independent variable to be erroneously identified as significant due to spurious, or *false,* correlation.

- *Leveraging Binary Variables to Account for Recent Trends* – Several of Minnesota Power's largest industrial and resale customers are in a time of significant change, and an accurate load forecast depends on properly identifying and accounting for these changes. Minnesota Power adjusts historical sales series to "back-out" recent large customer load additions and reductions to avoid double-counting customer usage in the forecast timeframe; once (partially) embedded in the econometric projection, and again through a post-regression load adjustment. This approach is appropriate when the load addition/loss is quantifiable (e.g., a new customer, or a new customer-owned generator).
  This approach is supplemented with the use of binary and trend variables that account for large changes in load that cannot be precisely quantified (such as a customer expansion that is not metered separately). The variables denote and account for a structural shift in a dependent variable (historical sales) and are then terminated at the start of the forecast timeframe to effectively "back out" this recent change so it can be accurately quantified and explicitly applied through a post-regression adjustment to the econometric series.

- *Polynomial temperature specification for peak demand* – The AFR 2025 peak demand model uses a third-degree (cubed) temperature series alongside an un-adjusted temperature series to capture the non-linear relationship of load to temperature. The two variables (cubed and un-adjusted) create a polynomial temperature specification.

- *Modeled Peak Demand using hour-specific weather observations* – Minnesota Power has modeled peak demand as a function of the weather observations specific to the hour in

which the peak occurred. The Company identified the historical peak date/times and queried an hourly weather observation dataset to identify the hourly temperature, humidity, and wind-chill coincident with the system peak. In theory, the temperature at the time of the peak should be more closely related with the load than a daily high or low temperature. As a rule, all models are ordinary least squares ("OLS"), which are simple, transparent, explainable, and produce optimal estimates of the coefficients. Once input variables' coefficients are determined to be statistically significant and models are finalized, they form the basis of the "econometrically determined" outlook for energy sales, peak demand, and customer count. Assumptions for future load additions/losses and/or adjustments to account for recent customer expansions are applied to the econometric outlook to produce Minnesota Power's final energy sales, peak demand, and customer count outlook.

C. Statistical Techniques, Typical Computations Specifying Variables and Data, and the Results of Appropriate Statistical Tests (7610.0320, Subp. 1.D)

This section presents the statistical detail of all models utilized in the development of the AFR 2025 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

Models are shown with each variable's coefficient, P-value and Heteroscedasticity and Autocorrelation Consistent ("HAC") P-value. Minnesota Power includes the HAC P-value as it adjusts for biases resulting from autocorrelation and/or heteroscedasticity. These HAC-adjusted P-values are used to determine inclusion/exclusion in the model. Coefficients themselves are not affected by this adjustment. Below, for each model, a graph displays the historical series, growth rates for timeframes of interest, and a comparison of this year's forecast to last year's forecast. There is a table that shows a more focused view of the forecast with a shorter historical timeframe to examine year-over-year growth rates, and key diagnostic statistics for the OLS model are shown in a table in the bottom left corner of each page. Minnesota Power also offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues. In addition, this portion of the documentation compares this year's model with last year's model and discusses findings or insights gained.

Figure 2: Residential Customer Count – Expected Scenario

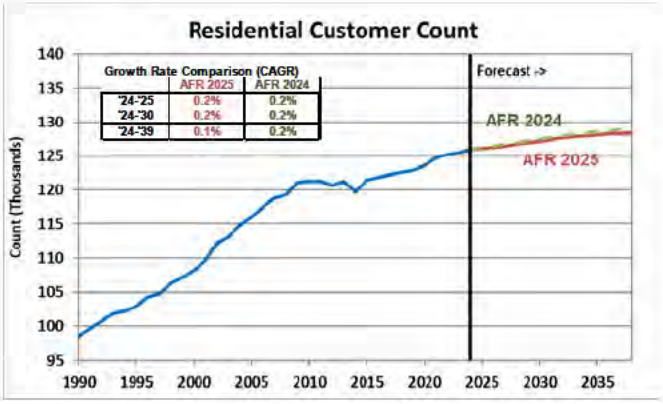
Residential Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	98,162.90	0.00%	0.00%
Bill_Res_1	(2,152.26)	0.00%	0.00%
Bill_Res_2	(2,789.99)	0.00%	0.00%
Dum_2009_2039	8,164.46	0.00%	0.00%
T_2009_2039	(33.14)	0.00%	0.00%
Res_C_2021_2039	1,572.33	0.00%	0.00%
MSA_HousStart_Cumulative	1.07	0.00%	0.00%

Residential Customer Count		
	Count	Y/Y Growth
2012	120,697	
2013	121,314	0.5%
2014	121,601	0.2%
2015	121,515	-0.1%
2016	121,836	0.3%
2017	122,295	0.4%
2018	122,557	0.2%
2019	122,926	0.3%
2020	123,617	0.6%
2021	124,691	0.9%
2022	125,243	0.4%
2023	125,573	0.3%
2024	125,898	0.3%
2025	126,168	0.2%
2026	126,283	0.1%
2027	126,497	0.2%
2028	126,733	0.2%
2029	126,989	0.2%
2030	127,197	0.2%
2031	127,420	0.2%
2032	127,632	0.2%
2033	127,822	0.1%
2034	127,983	0.1%
2035	128,117	0.1%
2036	128,227	0.1%
2037	128,311	0.1%
2038	128,373	0.0%
2039	128,412	0.0%

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	6250
Durban-Watson	0.7
MAPE	0.27
In-Sample RMSE	409



Model Discussion

AFR 2025 has a slightly more conservative growth rate compared to AFR 2024. On average, AFR 2025 has a 0.1% growthrate in residential cutomer count compared to AFR 2024's growthrate of 0.2%.

The key economic variable driving the residential customer count projection was Duluth MSA Cumulative Housing Starts, which is a rolling accumulation of annual housing starts beginning in 1990. This transformation converts a rate variable into a level variable, which better describes the underlying long-term trend of customer growth.

A combination of binary and trend variables ("Dum_2009_2039"" and "T_2009_2039") denote post-recession shifts in the relationship of MSA housing starts and residential customer count; housing starts continued, but customer counts stalled. This may be due in part to a shift towards suburban construction, where home construction continued but just outside Minnesota Power service territory. Without these corrective binary and a trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

The "Res_C_2021_2039" binary variable begins in mid-2021 and denotes a realignment of the MSA housing starts metric and customer counts; the mid-pandemic increase in demand for housing appears to be driving residential development in Minnesota Power's service territory, leading to customer growth. Two binary variables (Bill_Res) account for divergence from long-term trends due to "seasonal billing" between 1994 and 2001. This accounting practice recorded customer counts from November to May as 2,000-6,000 lower than from June to October.

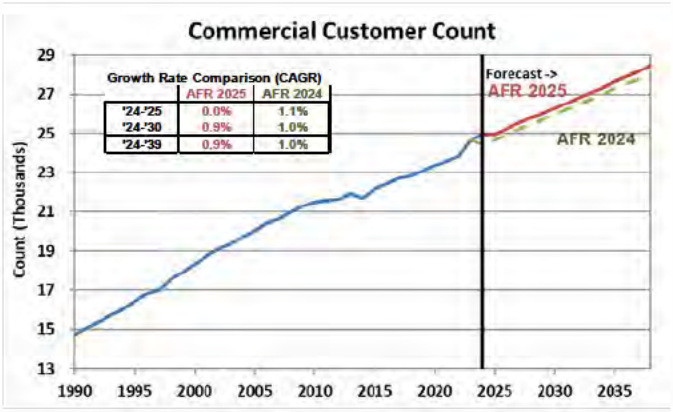
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model that's not over fit. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as the MAPE indicate model accuracy is comparable to AFR 2024 (0.27%).

Figure 3: Commercial Customer Count – Expected Scenario

Commercial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	12,385.00	0.00%	0.00%
T	24.78	0.00%	0.00%
Dum_2010_2039	846.27	0.00%	2.11%
T_2010_2039	(5.48)	0.00%	0.01%
MSA_Real_GMP	0.24	0.00%	0.00%



Commercial Customer Count		
	Count	Y/Y Growth
2012	21,614	
2013	21,915	1.4%
2014	22,096	0.8%
2015	22,170	0.3%
2016	22,420	1.1%
2017	22,695	1.2%
2018	22,834	0.6%
2019	23,059	1.0%
2020	23,346	1.2%
2021	23,580	1.0%
2022	23,816	1.0%
2023	24,650	3.5%
2024	24,962	1.3%
2025	24,963	0.0%
2026	25,255	1.2%
2027	25,531	1.1%
2028	25,775	1.0%
2029	26,012	0.9%
2030	26,270	1.0%
2031	26,543	1.0%
2032	26,788	0.9%
2033	27,060	1.0%
2034	27,336	1.0%
2035	27,615	1.0%
2036	27,892	1.0%
2037	28,163	1.0%
2038	28,442	1.0%
2039	28,723	1.0%

Model Statistics	Magnitude
Adjusted R^2	99.7%
AIC	5472
Durban-Watson	0.5
MAPE	0.57
In-Sample RMSE	162

Model Discussion

The AFR 2025 Commercial Count forecast has a similar long-term annual growth rate to AFR 2024, both averaging approximately 1.0%.

The key economic driver of customer growth was Duluth MSA Real Gross Metro Product (GMP). Local GMP has historically tracked well with commercial customer counts, but COVID-19 caused the two series (GMP and commercial counts) to diverge, likely due to government supports like the Paycheck Protection Program (PPP) and Minnesota Power suspending disconnections for small business (general service) customers. A Trend variable accounts for some of this underlying customer count growth that appears unrelated to immediate economic conditions.

A combination of binary and trend variables ("Bi_2010_2039" and "T_2010_2039") denote a post-Great Recession, abrupt shift in customer count growth – customer counts grew at an average rate of 2.0% prior to 2010, and only 0.8% since. Without these corrective binary and trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are very similar: MAPE rose slightly compared to the 2024 model (0.49%), and RMSE is 162 vs. 158 in the 2024 model.

Figure 4: Industrial Customer Count – Expected Scenario

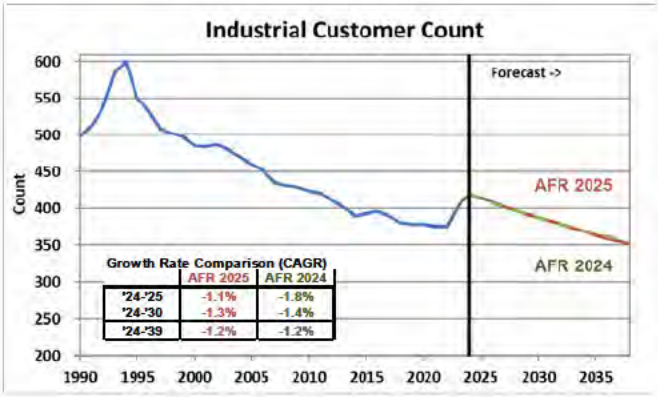
Industrial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	431.35	0.00%	0.00%
T	(0.35)	0.00%	0.00%
Ind_1991_1997	43.52	0.00%	0.00%
MFG_13	0.004	0.00%	0.00%
Ind_2023_2039	55.234	0.00%	0.00%

Industrial Customer Count		
	Count	Y/Y Growth
2012	411	
2013	402	-2.2%
2014	394	-2.0%
2015	394	-0.1%
2016	396	0.6%
2017	390	-1.6%
2018	380	-2.5%
2019	379	-0.3%
2020	378	-0.2%
2021	375	-0.7%
2022	375	0.0%
2023	403	7.4%
2024	419	4.0%
2025	415	-1.1%
2026	408	-1.6%
2027	402	-1.4%
2028	397	-1.4%
2029	392	-1.2%
2030	388	-1.1%
2031	383	-1.1%
2032	379	-1.2%
2033	373	-1.3%
2034	368	-1.4%
2035	363	-1.3%
2036	359	-1.1%
2037	355	-1.1%
2038	351	-1.1%
2039	347	-1.2%

Model Statistics	Magnitude
Adjusted R^2	92.9%
AIC	3564
Durban-Watson	0.1
MAPE	2.18
In-Sample RMSE	17



Model Discussion

The AFR 2025 and AFR 2024 forecast annual growth rate for industrial customer both are approximately -1.2%, with the customer count projection declining to 347 by 2039 compared to AFR 2023's customer count of 354 by 2038.

The key economic driver of industrial customer count was Manufacturing sector employment (13-County). This sector was a good representation of Minnesota Power's industrial customers as it encompasses the range of business sectors in this class, including: wood products, pulp/paper/paperboard mills, food products, foundries, and petroleum refining.

"Ind_1991_1997" is a binary variable that denotes the January-1991 through December-1997 timeframe where Industrial customer counts increased and then decreased very rapidly: a 23.7% increase from January-1991 to June-1994, followed by a 36.2% decrease from June-1994 to December-1997. These dramatic swings in customer counts were most likely due to accounting classifications of customers at the time and this binary variable effectively "backs-out" these points from consideration to avoid biasing the model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. The MAPE has decreased from 2.21 in AFR 2024 to 2.18 in the AFR 2025 model, and RMSE is unchanged at 17 from last year's model.

Figure 5: Public Authorities Customer Count – Expected Scenario

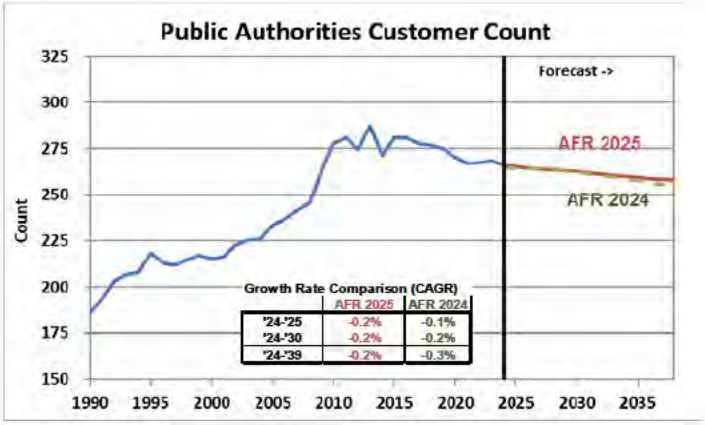
Public Authorities Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	126.59	0.00%	0.00%
Dum_Gov_Light_2009_2039	40.02	0.00%	0.00%
Dum_2015_2039	68.63	0.00%	0.00%
T_2015_2039	(0.21)	0.00%	0.00%
GRP_13	4.39	0.00%	0.00%

Public Auth. Customer Count		
	Count	Y/Y Growth
2012	275	
2013	287	4.6%
2014	282	-1.9%
2015	281	-0.4%
2016	281	-0.1%
2017	278	-1.0%
2018	277	-0.3%
2019	275	-0.7%
2020	271	-1.5%
2021	267	-1.4%
2022	268	0.1%
2023	269	0.5%
2024	266	-1.1%
2025	265	-0.2%
2026	264	-0.4%
2027	264	-0.2%
2028	263	-0.2%
2029	263	-0.1%
2030	263	-0.1%
2031	262	-0.3%
2032	261	-0.3%
2033	260	-0.3%
2034	260	-0.2%
2035	259	-0.2%
2036	259	-0.2%
2037	259	-0.2%
2038	258	-0.1%
2039	258	-0.1%

Model Statistics	Magnitude
Adjusted R^2	97.1%
AIC	2618
Durban-Watson	0.4
MAPE	1.68
In-Sample RMSE	5.4



Model Discussion

The AFR 2025 forecast annual growth rate for public authorities customer count has increased from AFR 2024's -0.4% to a -0.2% average decrease.

The key economic driver of customer growth was 13-County Gross Regional Product (GRP). GRP is a measure of general economic health that correlates with local government revenues, and presumably local government accounts with Minnesota Power. A binary variable starting in July-2009 accounts for a step-change or "systematic shift" in the historical accounting data. The corrective binary variables shift the forecast up slightly to avoid improbable decreases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

The combination of a binary and a trend variable for the 2015-2039 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2025) to align with the last historical year (2024). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate customer count, and the 2024 forecast value confirms this. Without these binary and trend variables, the model would project an abrupt and unreasonably large increase in customers in 2024.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are comparable to the AFR 2024 model: MAPE decreased slightly to 1.68 compared to AFR 2024's 1.84, and RMSE also decreased to 5.4 in AFR 2025 compared to 2024's

Figure 6: Street Lighting Customer Count – Expected Scenario

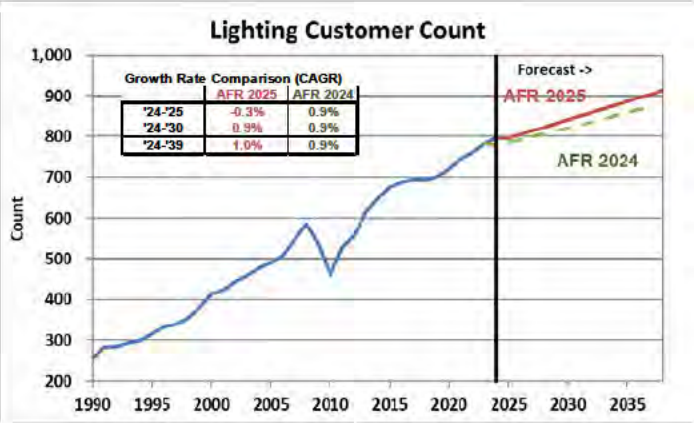
Street Lighting Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	227.20	0.00%	0.00%
T	1.47	0.00%	0.00%
Light_09_14	(723.40)	0.00%	0.00%
Light_T_09_14	2.46	0.00%	0.00%
Dum_Light_2015_2039	188.34	0.00%	0.00%
T_Light_2015_2039	(0.64)	0.00%	0.00%
Light_2020_2039	26.73	0.00%	0.19%
Light_2020_T	(2.14)	0.19%	1.55%

Lighting Customer Count		
	Count	Y/Y Growth
2012	559	
2013	615	10.0%
2014	648	5.4%
2015	673	2.0%
2016	689	2.4%
2017	695	0.9%
2018	693	-0.3%
2019	701	1.1%
2020	720	2.7%
2021	746	3.7%
2022	762	2.1%
2023	784	2.9%
2024	799	1.8%
2025	796	-0.3%
2026	805	1.1%
2027	814	1.1%
2028	823	1.1%
2029	833	1.1%
2030	842	1.1%
2031	851	1.1%
2032	860	1.1%
2033	869	1.1%
2034	878	1.0%
2035	887	1.0%
2036	896	1.0%
2037	905	1.0%
2038	915	1.0%
2039	924	1.0%

Model Statistics	Magnitude
Adjusted R^2	99.2%
AIC	3467
Durban-Watson	0.2
MAPE	2.68
In-Sample RMSE	15



Model Discussion

The AFR 2025 forecast annual growth rate for street lighting customer count is nearly identical to AFR 2024, increasing from 0.9% in AFR 2024 to 1.0% in AFR 2025.

A combination of a binary and trend variable starting in July-2009 account for a step-change or "systematic shift" in the historical accounting data and extends through December-2014.

A combination of a binary variable and trend variable denoting the 2015-2038 timeframe pick up where the 2009-2014 variable left off, shifting the level and trend of the estimate to align with the updated accounting data going forward.

The combination of a binary and a trend variable for the 2020-2039 timeframe (beginning early-2020) mark a shift in the level and trend of the estimate to align with recent customer growth (this was in addition to the 2015-2039 change in forecast trajectory captured by the variables above). These variables effectively shift the first forecast year (2025) to align with the last historical year (2024). Without these corrective variables, 2025 monthly forecasted values would be understated.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as MAPE and RMSE are nearly identical.

Figure 7: Residential Energy Use – Expected Scenario

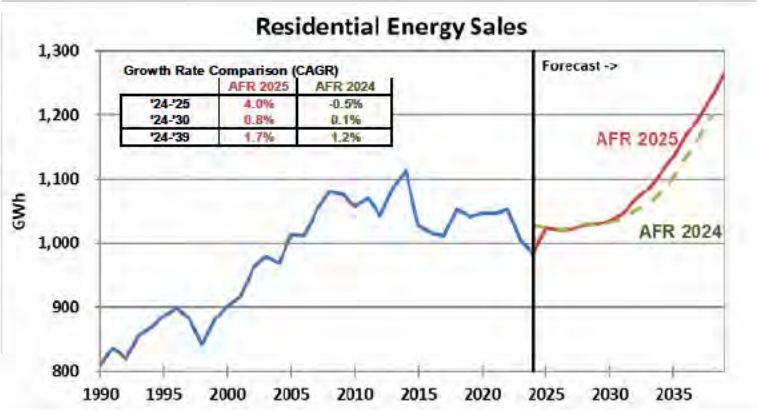
Residential Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	17.06	0.00%	0.00%
Feb	(1.4747947)	0.00%	0.26%
Mar	(2.0783349)	0.00%	0.00%
Apr	(1.6993026)	0.00%	0.00%
May	(1.6054394)	0.00%	0.00%
Jun	(1.1956499)	0.06%	0.00%
Oct	(2.6531024)	0.00%	0.00%
Nov	(2.2446113)	0.00%	0.00%
Dum_2008_2039	1.6895431	0.00%	0.00%
EE_Res	(0.0000146)	0.00%	0.00%
Dul_HDDpd	0.2502352	0.00%	0.00%
Dul_CDDpd	1.0469543	0.00%	0.00%

Residential Energy Sales		
	MWh	Y/Y Growth
2012	1,043,281	
2013	1,086,481	4.1%
2014	1,112,579	2.4%
2015	1,026,454	-7.7%
2016	1,015,465	-1.1%
2017	1,010,955	-0.4%
2018	1,052,800	4.1%
2019	1,042,353	-1.0%
2020	1,046,910	0.4%
2021	1,046,341	-0.1%
2022	1,053,657	0.7%
2023	1,004,064	-4.7%
2024	983,679	-2.0%
2025	1,022,765	4.0%
2026	1,019,977	-0.3%
2027	1,020,482	0.0%
2028	1,027,198	0.7%
2029	1,028,736	0.1%
2030	1,034,807	0.6%
2031	1,045,933	1.1%
2032	1,066,696	2.0%
2033	1,084,161	1.6%
2034	1,108,374	2.2%
2035	1,135,393	2.4%
2036	1,168,074	2.9%
2037	1,194,604	2.3%
2038	1,229,314	2.9%
2039	1,265,699	3.0%

Model Statistics	Magnitude
Adjusted R^2	85.9%
AIC	1659
Durban-Watson	2.0
MAPE	5.40
In-Sample RMSE	1.7



Model Discussion

The graph above shows the final residential energy sales outlook, which combines the econometric forecast (i.e. the product of the use-per-customer per day model and the customer count model) and the projected impacts of light-weight electric vehicle and distributed solar adoption.

The AFR 2025 residential per-customer use model did not use an employment or demographic indicator variable as these variables rarely correlate well with per-customer usage and often are not intuitive or explainable. Instead, the Company uses weather and seasonal binary variables to indicate month-to-month variation in sales, a time-trend to indicate long-term underlying growth, and an Energy Efficiency variable to explain recent changes (since 2007) in the underlying trend of per-customer usage growth.

The "EE_Res" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year.

The AFR 2025 model uses simple monthly HDD and CDD (per-day) specifications. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month – this results in the "per-day" series HDDpd and CDDpd.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 5.4% vs 5.45% in the 2024 model, and RMSE in AFR 2025 is 1.7 compared to AFR 2024's 1.8.

Figure 8: Commercial Energy Use – Expected Scenario

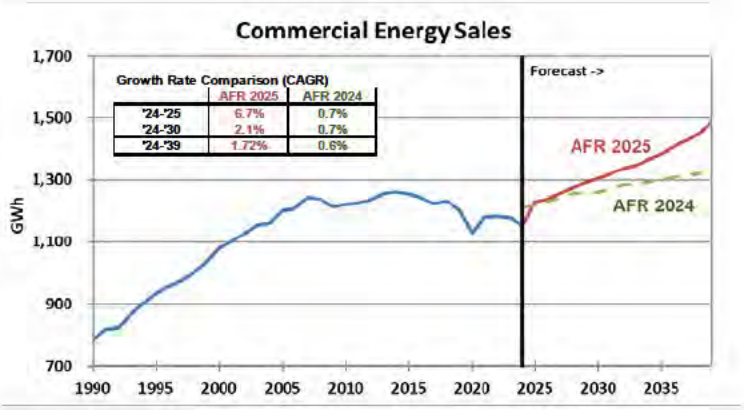
Commercial Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	53.83	0.00%	0.00%
Jan	(6.58)	0.04%	0.12%
Apr	(11.92)	0.00%	0.00%
May	(9.02)	0.00%	0.00%
Aug	10.71	0.00%	0.00%
Sep	7.15	0.02%	0.01%
Oct	(10.06)	0.00%	0.00%
Nov	(11.56)	0.00%	0.00%
Dum_2007_2039	3.88	0.59%	0.02%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.4681	0.00%	0.00%
Dul_CDDpd	4.16	0.00%	0.00%
EmpltoPop_13	227.01	0.00%	0.00%

Commercial Energy Sales		
	MWh	Y/Y Growth
2012	1,237,386	
2013	1,256,540	1.5%
2014	1,262,464	0.5%
2015	1,254,881	-0.6%
2016	1,243,045	-0.9%
2017	1,223,786	-1.5%
2018	1,233,117	0.8%
2019	1,202,403	-2.5%
2020	1,131,101	-5.9%
2021	1,181,246	4.4%
2022	1,181,683	0.0%
2023	1,178,825	-0.2%
2024	1,152,595	-2.2%
2025	1,229,281	6.7%
2026	1,239,950	0.9%
2027	1,256,533	1.3%
2028	1,275,654	1.5%
2029	1,291,103	1.2%
2030	1,304,840	1.1%
2031	1,319,861	1.2%
2032	1,336,171	1.2%
2033	1,347,900	0.9%
2034	1,366,025	1.3%
2035	1,385,166	1.4%
2036	1,409,117	1.7%
2037	1,426,992	1.3%
2038	1,451,394	1.7%
2039	1,488,083	2.5%

Model Statistics	Magnitude
Adjusted R^2	70.2%
AIC	3044
Durban-Watson	2.5
MAPE	4.61
In-Sample RMSE	9



Model Discussion

The AFR 2025 forecast of commercial energy use is higher than AFR 2024 due to forecasted higher use-per-customer. The commercial energy use forecast grows at a 1.7% per year (average) pace, compared to the AFR 2024 forecast of 0.6%.

The graph above shows the final commercial energy sales outlook, which combines the econometric forecasts of use-per-customer per day and customer count, along with arithmetic adjustments for: 1) Adoption of medium and heavy-duty electric vehicles used for commercial and fleet operations, 2) the planned installation of new generation at a specific customer's facility, and 3) the projected impacts of distributed solar adoption.

The key driver of this year's commercial energy use model was the 13-County Employment-to-Population ratio. COVID-19 resulted in a substantial loss of energy sales without any corresponding decrease in customer counts, which is unprecedented and difficult to model with the typical economic indicators. The Employment-to-Population ratio indicates the rate of employment utilization, and both correlates and explains commercial property/account energy utilization during the initial economic contraction and recovery from COVID-19.

"Dum_2007_2039" is a binary variable starting in 2007 that accounts for a step-change, or "systematic shift," in energy use for this class around the time of the 2007 Energy Act. Sales to this class have remained essentially flat since this time (aside from the COVID-19 recession of 2020).

The AFR 2025 model uses an Energy Efficiency variable as a predictor of commercial per-customer sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared of 70.2% indicates there's just a moderate traditional "goodness-of-fit", but this was the case in last year's model as well (Adjusted R-Squared was only 68%) and the Company does not consider the R-Squared an indicator of predictive quality. Minnesota Power leverages other objective metrics for determining model selection such as Mean Absolute Percent Error and Root Mean Square Error.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 4.61% vs. 4.57% in the 2024 model, and RMSE is unchanged at 9 in both the 2025 and 2024 models.

Figure 9: Mining and Metals Energy Use – Expected Scenario

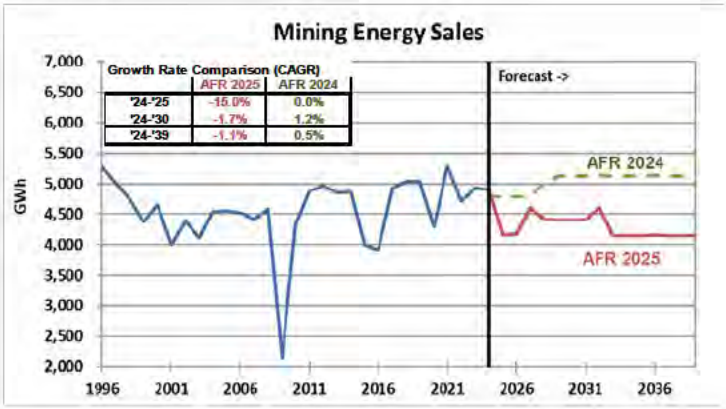
Mining and Metals Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	6,575.01	0.00%	0.00%
LTV_T	(24.73)	0.00%	0.01%
Mine_Maint	(313.65)	18.61%	5.16%
Mine_Downturn1	(3,294.14)	0.00%	0.00%
Mine_Downturn2	(1,783.56)	0.00%	0.00%
Mine_Downturn3	(1,496.32)	0.01%	0.00%
Metals	148.27	28.21%	23.60%
MN_Iron_IPI	58.94	0.00%	0.00%

Mining and Metals Energy Sales		
	MWh	Y/Y Growth
2012	4,968,517	
2013	4,851,094	1.9%
2014	4,879,520	-2.4%
2015	4,000,557	0.6%
2016	3,908,570	-18.0%
2017	4,930,188	-2.3%
2018	5,039,138	26.2%
2019	5,038,704	2.2%
2020	4,295,593	0.0%
2021	5,280,743	-14.7%
2022	4,712,773	22.9%
2023	4,935,265	-10.8%
2024	4,896,466	4.7%
2025	4,161,137	-15.0%
2026	4,165,169	0.1%
2027	4,603,455	10.5%
2028	4,417,259	-4.0%
2029	4,407,031	-0.2%
2030	4,408,133	0.0%
2031	4,407,060	0.0%
2032	4,617,835	4.8%
2033	4,149,141	-10.1%
2034	4,149,502	0.0%
2035	4,148,925	0.0%
2036	4,159,739	0.3%
2037	4,149,659	-0.2%
2038	4,150,970	0.0%
2039	4,150,401	0.0%

Model Statistics	Magnitude
Adjusted R^2	71.8%
AIC	5815
Durban-Watson	1.0
MAPE	5.41
In-Sample RMSE	993



Model Discussion

The AFR 2025 outlook for mining and metals energy use is lower than the AFR 2024 projection due to decreased customer operations (post-regression adjustments). The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load adjustments.

The key economic driver of this year's mining energy use model was the Minnesota (MN) Iron IPI, which measures the real production output nationwide in the industry and is scaled to MN-only.

This year's model incorporates several binary variables to control for known or suspected definitional changes in the historical mining energy sales series. These variables have been added with the goal of avoiding bias in the IPI's coefficient for these past definitional changes in the mining and metals sales series.

"LTV_T" is a trend variable that denotes the timeframe from 1996-2001, when a large mining customer ended operations. The variable accounts for a possible change in relationship between Minnesota Power mining customer energy and the MN IPI, and allows for a more exact estimation of the relationship during the current paradigm.

The "Mine_Maint" binary variable denotes and normalizes for some of the observable seasonality in mining operations.

The "Mine_Downturn1" binary variable denotes the recession period from early 2009 to early 2010, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Mine_Downturn2" binary variable denotes a timeframe from May-2015 to February-2017, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Mine_Downturn3" binary variable denotes months between April-2020 and November-2020, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Metals" binary variable denotes operations of four smaller metals customers in the January-2010 to September-2016 timeframe. These customers' are backed out of the historical series prior to regression modeling, but their historical production contributed to national iron IPI. This binary variable ("Bi_Mine6") explains the temporary distortion in the energy-sales-to-National-IPI relationship.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The P-values suggests all variables' coefficients' are significant-with the exception of "Metals". It was determined this variable was needed because this variable was used in last year's model, i.e. for year-to-year consistency, and this is an important factor shaping consumption in the forecast timeframe. In-sample error metrics are similar: the MAPE is 5.4 compared to 2023 model at 5.7%, but the RMSE is lower at 993 vs. 1018 in the 2024 model.

Figure 10: Paper and Pulp Products Energy Use – Expected Scenario

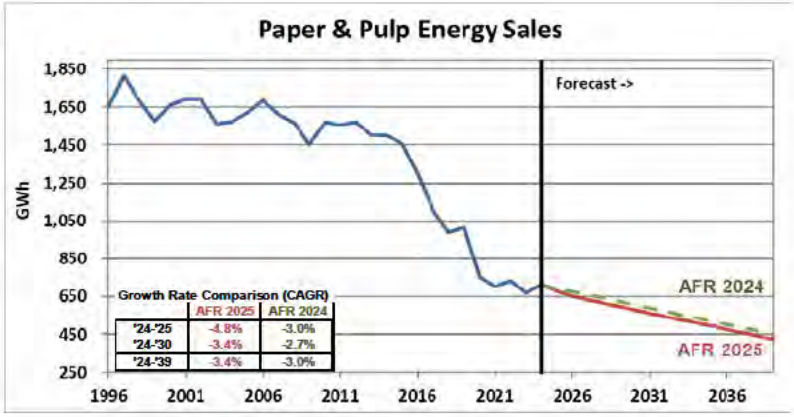
Paper and Pulp Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	4,696.26	0.00%	0.00%
T	(3.93)	0.00%	0.00%
Mar	132.30	15.11%	1.48%
Jun	162.13	7.88%	1.28%
Aug	275.51	0.29%	0.01%
Sep	305.79	0.11%	0.01%
Oct	262.58	0.49%	0.05%
Dec	(131.28)	15.43%	5.68%
Term_Paper_20_38	(1,503.94)	0.00%	0.00%
Paper_IPI_diff	27.16	13.04%	8.30%
Paper_22_Gen	961.23	0.45%	0.00%

Paper & Pulp Energy Sales		
	MWh	Y/Y Growth
2012	1,570,852	
2013	1,505,113	0.7%
2014	1,498,810	-4.2%
2015	1,456,091	-0.4%
2016	1,302,920	-2.9%
2017	1,104,160	-10.5%
2018	987,208	-15.3%
2019	1,013,971	-10.6%
2020	752,072	2.7%
2021	701,549	-25.8%
2022	735,506	-6.7%
2023	668,406	4.8%
2024	714,239	-9.1%
2025	679,876	-4.8%
2026	650,672	-4.3%
2027	632,557	-2.8%
2028	617,031	-2.5%
2029	597,978	-3.1%
2030	580,630	-2.9%
2031	563,325	-3.0%
2032	547,506	-2.8%
2033	528,671	-3.4%
2034	511,456	-3.3%
2035	494,241	-3.4%
2036	478,266	-3.2%
2037	459,810	-3.9%
2038	442,594	-3.7%
2039	425,378	-3.9%

Model Statistics	Magnitude
Adjusted R^2	78.2%
AIC	5278
Durban-Watson	0.5
MAPE	9.27
In-Sample RMSE	458



Model Discussion

The AFR 2025 outlook for paper and wood products energy requirements is slightly lower than the AFR 2024 projection. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

The AFR 2025 model was driven by the Industrial Production Index (IPI) for Paper, which measures the real production output nationwide in the industry, and indicates an underlying secular decline of the North American Paper industry (and demand for paper products).

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's reasonable goodness-of-fit, and In-sample error metrics are a bit different: MAPE is slightly lower in AFR 2025 at 9.3 compared to 9.4 in AFR 2024, and RMSE decreased to 458 vs. 466 in the 2024 model.

The AIC indicates a highly parsimonious model. HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

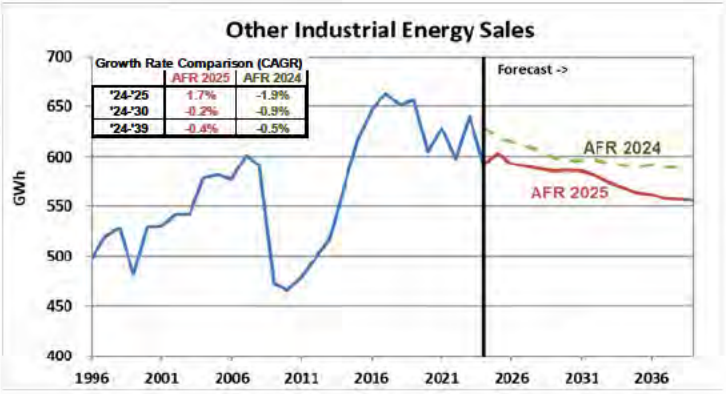
Figure 11: Other Industrial Energy Use – Expected Scenario

Other Industrial Energy Use - Expected Scenario

Estimation Start/End:
Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value

Other Industrial Energy Sales		
	MWh	Y/Y Growth
2012	498,474	
2013	517,786	3.9%
2014	568,206	9.7%
2015	616,625	8.5%
2016	646,339	4.8%
2017	663,444	2.6%
2018	651,546	-1.8%
2019	656,590	0.8%
2020	605,277	-7.8%
2021	629,017	3.9%
2022	597,430	-5.0%
2023	640,688	11.3%
2024	592,586	-5.3%
2025	602,801	1.7%
2026	593,039	-1.6%
2027	590,510	-0.4%
2028	587,261	-0.6%
2029	585,797	-0.2%
2030	586,415	0.1%
2031	585,437	-0.2%
2032	580,754	-0.8%
2033	573,771	-1.2%
2034	568,624	-0.9%
2035	563,769	-0.9%
2036	562,026	-0.3%
2037	557,985	-0.7%
2038	556,899	-0.2%
2039	555,623	-0.2%



Model Discussion

Minnesota Power has broken out Other Industrial into four sectors: 1) Pipelines, 2) Foundries, 3) Food Products, and 4) Remaining.

Due to several Other Industrial sub-sectors containing just two or three customers, these sector-level forecasts could imply trade secret information. Minnesota Power will only show the aggregate of all sectors ("Other Industrial") in the graph above and table to the left. The sector-specific models of projected energy and the model discussions are discussed on the following pages, and are marked "TRADE SECRET" due to the limited number of customers in each sector.

Figure 12: Pipelines Energy Use – Expected Scenario

Pipelines Energy Use - Expected Scenario

Estimation Start/End: 1/1996 - 12/2024
Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	(725.78)	0.09%	3.06%
Term_13_23	(5,208.81)	0.00%	0.00%
Term_13_23_T	18.06	0.00%	0.00%
TTU_13	0.03	0.00%	0.01%

Model Statistics	Magnitude
Adjusted R^2	68.8%
AIC	4320
Durban-Watson	0.5
MAPE	13.49
In-Sample RMSE	117

Model Discussion

Minnesota Power modeled and projected energy sales to pipeline customers individually, independent of total Other Industrial sales.

The AFR 2025 econometric driver for the pipelines model was 13-County Trade, Transportation, & Utilities (TTU) Employment. The TTU employment variable was selected as it directly encompasses the pipeline sector being modeled and highlights a major advantage of more granular forecasting for Other Industrial sub-sectors – economic variable specificity (last year's total Other Industrial model had 13-County Total Non-Farm Employment as the economic variable).

A binary ("Term_13_23") and a trend variable ("Term_13_23_T") denote the period in which a large pipeline customer began adding substantial load, and drove the majority of the energy use increase in the customer class. The binary and trend variables effectively "back-out" this recent load addition, so this customer's expected energy use can be addressed in isolation through a post-regression load addition to avoid double-counting.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are notably comparable to last year's model: MAPE increased to 13.49% compared to 2024 models MAPE of 12.18%. RMSE is higher than the AFR 2024 model at 117. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 13: Foundries Energy Use – Expected Scenario

Foundries Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(416.42)	0.00%	0.01%
Foundry_1999_2000	(64.47)	0.00%	0.00%
Foundry_2011_2014	55.89	0.00%	0.00%
TotNonF_StLou	0.01	0.00%	0.00%
Foundry_IPI	1.18	0.00%	0.00%
Foundry_2024_2039	(70.24)	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	56.2%
AIC	3390
Durban-Watson	0.9
MAPE	8.69
In-Sample RMSE	31

Model Discussion

Minnesota Power modeled and projected energy sales to foundry customers individually, independent of total Other Industrial sales.

The Foundries energy use model leveraged two economic variables: Total St. Louis County Non-Farm Employment, and IPI for Primary Metals. The IPI for Primary Metals measures the national level real output in the industry, and is the model's indicator of national demand of primary metals products. St. Louis County non-farm employment is a more granular indicator of local business operations, and explains local foundry operations that may deviate from the national trend. All of Minnesota Power's foundry customers are located in St. Louis County.

"Foundry_1999_2000" is a binary variable denoting the 1999-2000 timeframe when energy sales began decreasing ahead of the national-level Primary Metals IPI-recognized-downturn due to a local mining customer winding down operations. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

"Foundry_2011_2014" is a binary variable denoting the 2011-2014 timeframe and represents a customer that expanded operations temporarily, diverging from the national-level Primary Petals IPI. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are comparable to last year's model: MAPE is 8.69% vs 8.77% in the AFR 2024 model, and RMSE is 31, unchanged from 2024's model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 14: Food Products Energy Use – Expected Scenario

Food Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(297.88)	0.00%	0.13%
LPP_2015_2039	24.63	0.00%	0.02%
Food_IPI	4.84	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	72.1%
AIC	2984
Durban-Watson	1.2
MAPE	7.52
In-Sample RMSE	17

Model Discussion

Minnesota Power modeled and projected energy sales to food product customers individually, independent of total Other Industrial sales.

Energy sales to the food products sector was modeled using the IPI for Food Products (Food, Beverage, and Tobacco). The IPI for Food Products measures the real production output nationwide in the industry, and indicates an underlying growth trend in this class.

"LLP_2015_2039" is a binary variable denoting the 2015-2039 timeframe. This variable represents a new level of sales following period of expansion for one of the customers in this class (beginning in 2015) and continues throughout the forecast timeframe. A binary variable approach is utilized as Minnesota Power is not adjusting the econometric model in the forecast timeframe to account for increased sales.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also comparable to last year's model: MAPE is 7.52 vs. 7.60% in AFR 2024, and RMSE is consistant at 17 vs. 17 in AFR 2024 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 15: Other Industrial Remaining Energy Use – Expected Scenario

Other Industrial Remaining Energy Use - Expected Scenario

Estimation Start/End:	1/2001 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	0.36	0.00%	0.00%
Misc_Ind_2001_2002	0.42	0.00%	0.00%
Rem_2023_2039	0.15	0.00%	0.00%
MFG_StLou	0.00	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	53.4%
AIC	-484
Durban-Watson	2.0
MAPE	9.47
In-Sample RMSE	0.1

Model Discussion

Minnesota Power modeled and projected energy sales to other industrial: remaining customers individually, independent of total Other Industrial sales. The other industrial: remaining sub-sector includes all industrial customer usage not accounted for in: Mining, Paper, Pipelines, Foundries, and Food Product Manufacturing.

The sole econometric variable used in the other industrial remaining model was St. Louis County Manufacturing Employment. Many of the customers in this class are either directly involved in manufacturing, or supply manufacturers with the goods/inputs they need to create a finished product to sell. Several of the larger customers in this class are located in St. Louis County; because of this, Minnesota Power selected the more granular variable to inform the model, instead of a more general/broader Manufacturing employment series.

"Misc_Ind_2021_2002" is a binary that indicates months in the 2001-2002 timeframe where energy sales have erroneous values. This binary essentially removes the erroneous data points from consideration in the model as they would have a negative influence on the model's integrity.

The Adjusted R-Squared indicates there's a moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also reasonable and comparable to AFR 2024 models: MAPE is less that AFR 2024 at 9.87 vs. 12.71, and RMSE is similar to AFR 2024 models at just 0.1 vs. 0.1. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 16: Public Authorities Energy Use – Expected Scenario

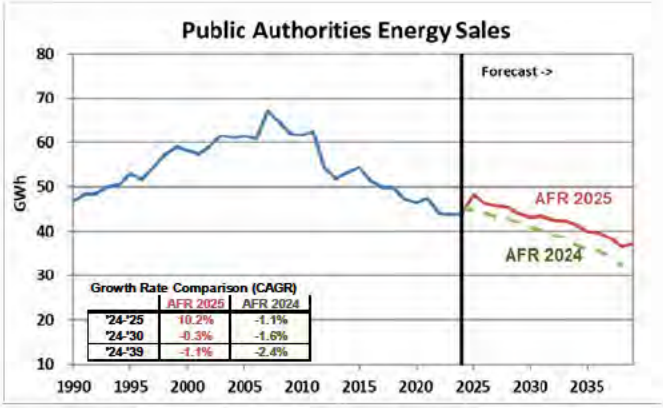
Public Authorities Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(1,200.17)	0.00%	0.00%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.18	0.66%	0.63%
Dul_CDDpd	4.32	0.00%	0.00%
MSA_Pop	4.90	0.00%	0.00%

Public Auth. Energy Sales		
	MWh	Y/Y Growth
2012	54,074	
2013	51,736	-4.3%
2014	53,237	2.9%
2015	54,471	2.3%
2016	51,455	-5.5%
2017	49,945	-2.9%
2018	49,884	-0.1%
2019	47,302	-5.2%
2020	46,375	-2.0%
2021	47,497	2.4%
2022	43,943	-7.5%
2023	43,671	-0.6%
2024	43,792	0.3%
2025	48,264	10.2%
2026	46,234	-4.2%
2027	45,622	-1.3%
2028	45,289	-0.7%
2029	43,877	-3.1%
2030	43,076	-1.8%
2031	43,454	0.9%
2032	42,475	-2.3%
2033	42,344	-0.3%
2034	41,618	-1.7%
2035	39,902	-4.1%
2036	39,588	-0.8%
2037	38,344	-3.1%
2038	36,491	-4.8%
2039	37,134	1.8%

Model Statistics	Magnitude
Adjusted R^2	42.1%
AIC	3697
Durban-Watson	2.0
MAPE	10.43
In-Sample RMSE	20



Model Discussion

The key economic driver of this year's Public Authorities energy use model was Duluth MSA Population. This variable indicates the underlying growth trend, which impacts government entities' operations (affecting energy use).

The AFR 2025 model uses an Energy Efficiency variable as a predictor of public authorities' energy sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The commercial-sector energy efficiency variable was used for the public authorities model since: 1) both customer groups are served by the same CIP program, and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers.

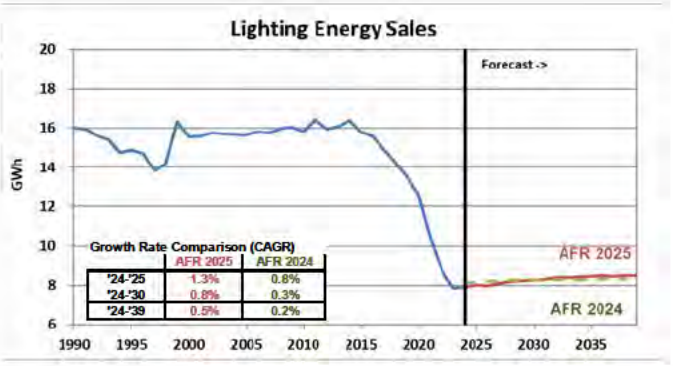
This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 10.43% vs. 10.35% in the 2024 model, and RMSE is unchanged at 20 in the 2025 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 17: Street Lighting Energy Use – Expected Scenario

Street Lighting Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	50.17	0.00%	0.00%
T	(0.01)	4.42%	5.18%
Jan	2.67	0.57%	0.10%
Feb	(2.01)	3.65%	0.42%
Mar	(9.06)	0.00%	0.00%
Apr	(13.69)	0.00%	0.00%
May	(19.45)	0.00%	0.00%
Jun	(22.50)	0.00%	0.00%
Jul	(22.13)	0.00%	0.00%
Aug	(18.75)	0.00%	0.00%
Sep	(11.49)	0.00%	0.00%
Oct	(8.28)	0.00%	0.00%
Nov	(2.94)	0.23%	0.00%
Dum_Light_1990_1999	(2.58)	0.23%	1.49%
LED_Lighting	106.46	0.00%	0.00%
LED_Lighting_T	(0.32)	0.00%	0.00%
NonWPI_StLou	0.002	2.25%	1.84%



Lighting Energy Sales		
	MWh	Y/Y Growth
2012	15,954	
2013	16,066	0.7%
2014	16,400	2.1%
2015	15,801	-3.7%
2016	15,588	-1.4%
2017	14,873	-4.6%
2018	14,206	-4.5%
2019	13,482	-5.1%
2020	12,617	-6.4%
2021	10,445	-17.2%
2022	8,744	-16.3%
2023	7,864	-10.1%
2024	7,907	0.6%
2025	8,010	1.3%
2026	7,983	-0.3%
2027	8,102	1.5%
2028	8,206	1.3%
2029	8,232	0.3%
2030	8,274	0.5%
2031	8,307	0.4%
2032	8,372	0.8%
2033	8,372	0.0%
2034	8,409	0.4%
2035	8,441	0.4%
2036	8,486	0.5%
2037	8,463	-0.3%
2038	8,475	0.1%
2039	8,473	0.0%

Model Statistics	Magnitude
Adjusted R^2	87.7%
AIC	2375
Durban-Watson	1.5
MAPE	6.37
In-Sample RMSE	4

Model Discussion

The AFR 2025 lighting per-day use model utilized St. Louis County Non-Wage Personal Income as a key economic/demographic indicator.

"Dum_Light_1990_1999" is a binary variable denoting the 1990-1999 timeframe and effectively shifts the level of the estimate to account for changes to the Company's accounting practices, which affected historical energy use data. The corrective binary shifts the forecast to avoid improbably changes in energy use, but does not impact the forecast trajectory; this is determined by the economic variables.

"LED_Lighting" and "LED_Lighting_T" are binary and trend variables denoting the 2017-2039 timeframe and effectively creates a new forecast trajectory influenced by levels starting in 2017 (this level is then held constant in the forecast timeframe after January-2025). This binary and trend combination shifts the forecast to account for Minnesota Power's LED lighting program's impact on energy use, and unlike "Dum_Light_1990_1999," it does impact the forecast trajectory; in addition to the economic variables.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 6.37% vs. 5.97% in the 2024 model, and RMSE is 4.0, the same as AFR 2024. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

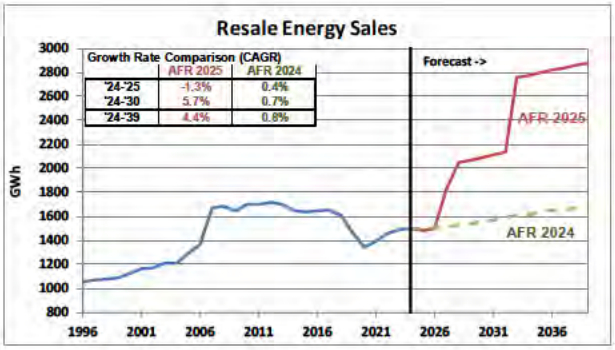
Figure 18: Resale Energy Use – Expected Scenario

Resale Energy Use - Expected Scenario

Estimation Start/End:
Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

Variable	Model Specifications			
	Coefficient	P-Value	HAC-P-Value	VIF

Resale Energy Sales		
	MWh	Y/Y Growth
2012	1,718,819	
2013	1,700,993	7.2%
2014	1,585,993	3.3%
2015	1,634,786	3.1%
2016	1,649,405	0.9%
2017	1,656,865	0.5%
2018	1,610,792	-2.8%
2019	1,468,108	-8.9%
2020	1,340,290	-8.7%
2021	1,393,315	4.0%
2022	1,456,237	4.5%
2023	1,487,350	2.0%
2024	1,499,240	0.7%
2025	1,479,765	-1.3%
2026	1,500,518	1.4%
2027	1,830,163	22.0%
2028	2,053,756	12.2%
2029	2,069,135	0.7%
2030	2,090,526	1.0%
2031	2,111,371	1.0%
2032	2,138,113	1.3%
2033	2,754,040	28.8%
2034	2,774,605	0.7%
2035	2,794,668	0.7%
2036	2,822,702	1.0%
2037	2,834,727	0.4%
2038	2,855,195	0.7%
2039	2,875,914	0.7%



Model Discussion

AFR 2025 is continuing the practice of forecasting each resale customer separately. Minnesota Power will not be providing graphs or tables that include forecast values for individual resale customers (similar to the approach mentioned above for Other Industrial).

Due to the trade secret nature of individual resale customers' forecasts, Minnesota Power will only be showing the aggregate forecast summary for total Resale energy sales in the graph above and table to the left.

Figure 19: System Peak Demand – Expected Scenario

System Peak Demand - Expected Scenario

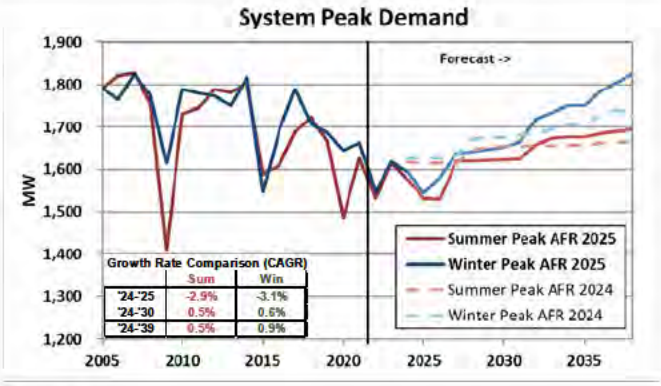
Estimation Start/End:	6/1999 - 12/2024
Unit Modeled/Forecast:	Monthly Peak Demand

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	499.98	0.00%	0.00%
WN_MWhpd	0.03	0.00%	0.00%
S	39.50	0.00%	0.01%
W	19.78	6.20%	1.02%
Dum_1999_2001	(35.22)	0.01%	0.00%
Dum_2008	105.34	0.04%	0.00%
WC_THI	(1.54)	0.00%	0.00%
WC_THI_3	0.0003	0.00%	0.00%
Jan_WN_MWhpd	(0.001)	4.29%	0.57%
Feb_WN_MWhpd	(0.001)	1.47%	0.37%
Mar_WN_MWhpd	(0.001)	0.58%	0.10%

System Peak Demand

	Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2012	1,789		2012	1,773	
2013	1,781	0%	2013	1,751	-1%
2014	1,805	1%	2014	1,818	4%
2015	1,589	-12%	2016	1,647	-15%
2016	1,610	1%	2016	1,683	9%
2017	1,688	5%	2017	1,789	6%
2018	1,724	2%	2018	1,707	-5%
2019	1,668	-3%	2019	1,687	-1%
2020	1,487	-11%	2020	1,646	-2%
2021	1,625	9%	2021	1,663	1%
2022	1,533	-6%	2022	1,550	-7%
2023	1,614	5%	2023	1,618	4%
2024	1,577	-2%	2024	1,594	-1%
2025	1,531	-3%	2025	1,544	-3%
2026	1,530	0%	2026	1,581	2%
2027	1,619	6%	2027	1,637	4%
2028	1,620	0%	2028	1,641	0%
2029	1,621	0%	2029	1,646	0%
2030	1,623	0%	2030	1,653	0%
2031	1,624	0%	2031	1,665	1%
2032	1,660	2%	2032	1,719	3%
2033	1,674	1%	2033	1,734	1%
2034	1,677	0%	2034	1,750	1%
2035	1,677	0%	2035	1,750	0%
2036	1,685	0%	2036	1,785	2%
2037	1,690	0%	2037	1,805	1%
2038	1,695	0%	2038	1,826	1%
2039	1,702	0%	2039	1,826	0%

Model Statistics	Magnitude
Adjusted R^2	83.6%
AIC	3161
Durban-Watson	1.0
MAPE	2.25
In-Sample RMSE	41



Model Discussion

The long-run outlook for Minnesota Power's system peak is higher than the 2024 outlook primarily due to higher econometric outputs compared to AFR 2024.

Temperature variables play a critical role in peak demand modeling, and both the definition and structure of these variables are important for interpreting the results. 2025 AFR used a third-degree polynomial specification on a Wind-Chill & Temperature Humidity Index. Peak demand is modeled as a function of the weather observations specific to the hour in which the peak occurred.

The 2025 AFR peak demand model utilized two binaries to indicate the month of the system's historical summer and winter peaks, and assumed this peak in July/January (respectively) throughout the forecast timeframe. Summer peaks typically occur in either July or August, historical winter peaks have occurred in November, December, February, but are most likely in January. This broad distribution of peak occurrence dilutes the model's measured seasonality, and as a result, the peak forecast will understate both the summer and winter peak demand figures. The utilization of these peak binaries focuses the seasonal peaks – which may have occurred in August or July, or December or January - into the months of July and January. This ensures seasonal peaks are not under forecast as a result of historical diversity in the timing of those seasonal peaks.

The model also includes two binaries ("Dum_1999_2001" and "Dum_2008") denoting periods of economic downturn for Minnesota Power's large industrial customers, resulting in abnormally low usage. During (or immediately following) these periods the normal relationship of Peak-to-Energy was affected by the idling of large, high load factor customers. These binaries effectively remove these downturn periods from consideration in the regression model and allow for more accurate estimation of model coefficients under more normal economic conditions.

There is no energy efficiency variable in the peak demand model and no explicit assumption for peak demand savings. Conservation impacts are accounted for by leveraging the energy sales forecast, which includes the effects of conservations, as the key input to the peak demand regression model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are very similar to the 2024 model: MAPE is 2.2% vs. 1.8% in the 2024 model, and RMSE is 41 vs. 33 in the 2024 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

D. Forecast Confidence and Historical Accuracy (7610.0320, Subp. 1.E and Subp. 1.F)

Minnesota Power has a strong record of both accurate forecasting and consistent improvements in forecast accuracy over time. Excluding the mining downturn years (2009/2010 and 2015/2016), as well as the 2020 COVID-19 recession (including 2021), each successive AFR has reduced its current-year energy sales forecast error, on average, by about 0.006 percent over the prior year.

Figures 20 through 22 show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Summer Peak, and Winter Peak demand. The bottom values in each column (**Bold**) represent the forecast accuracy in the current year, or the year it was produced. For example, in Figure 20 the bottom value of -15.7 percent in the 2020 column is the difference between the forecast produced in 2020 (AFR 2020) and the 2020 year-end actual. Similarly, the cell just above the current year accuracy (***Bold, Italic***) represents the accuracy of the forecast in the year immediately after its formulation. For example, AFR 2015 (formulated in 2015) forecast of 2016 was 5.9 percent (581 GWh) above the actual (due to effects of the Mining downturn).

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%	1.9%	-0.6%	**-2.2%**	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%										
AFR 2001		**-2.0%**	***0.3%***	3.4%	-1.0%	-3.1%	**-4.1%**	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%									
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	**-3.8%**	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-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%	-0.6%	2.0%	3.2%	15.2%	19.8%	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%	24.8%	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%	17.9%	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%	12.9%	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%	26.9%		
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	**-0.9%**	11.0%	15.9%	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%	26.1%	13.8%	20.5%	19.2%	21.3%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	1.0%	11.9%	**15.7%**	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%	26.4%	13.9%	20.5%	19.2%	21.4%
AFR 2013														**-0.2%**	***2.4%***	18.1%	24.6%	18.7%	**20.0%**	22.6%	40.2%	26.2%	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%**	16.3%	22.6%	20.9%	22.5%
AFR 2016																	**-1.4%**	***-4.3%***	-2.9%	-2.2%	20.4%	**10.1%**	19.3%	17.9%	19.6%
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 Foreast* **N.n%** = Current Year Forecast **N.n%** = 5 Year-Ahead Forecast

Figure 21: AFR Forecast Accuracy – Summer Peak

Summer System Peak Error

Forecast	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%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.1%										
AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.6%	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%	-6.9%	-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%	17.5%						
AFR 2005						-5.0%	-6.9%	-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%	2.2%	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%	-21.1%	-15.6%	-11.9%	-8.9%	-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%	4.5%	3.1%	7.3%	21.2%	11.7%	19.3%	14.1%	19.4%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.5%	18.0%	32.9%	22.2%	30.2%	24.2%	17.6%
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%	1.0%	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%	12.8%	21.5%
AFR 2018																			-0.6%	0.9%	15.4%	7.6%	14.8%	9.7%	16.1%
AFR 2019																				-1.1%	11.4%	3.2%	12.1%	7.6%	12.7%
AFR 2020																					-17.7%	-4.9%	1.3%	-3.9%	10.7%
AFR 2021																						-6.3%	0.8%	-3.5%	-1.8%
AFR 2022																							3.9%	1.2%	-1.4%
AFR 2023																								-2.2%	4.1%
AFR 2024																									-1.3%

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

Figure 22: AFR Forecast Accuracy – Winter Peak

Winter System Peak Error

Forecast	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																									
AFR 2001	0.4%	-1.0%	-2.6%	-4.1%	-6.2%	-5.7%	-3.6%	-6.0%	-2.7%	9.3%	-4.1%	-2.7%	-1.5%	1.8%	-1.1%										
AFR 2002		5.8%	3.1%	1.1%	-1.6%	-1.6%	0.2%	-2.6%	0.8%	13.3%	-0.4%	1.4%	2.9%	5.5%	2.5%	21.4%									
AFR 2003			1.1%	0.2%	-1.6%	-0.9%	1.3%	-1.3%	2.0%	15.1%	0.2%	1.8%	2.8%	4.9%	1.7%	20.1%	11.2%								
AFR 2004				-5.2%	-7.4%	-6.7%	-4.4%	-6.6%	-3.1%	9.0%	-4.1%	-2.1%	-0.3%	2.4%	-0.2%	18.4%	10.2%	5.7%							
AFR 2005					-5.0%	-4.3%	-0.9%	-3.6%	4.2%	16.6%	1.9%	5.1%	7.6%	11.2%	8.9%	29.9%	21.4%	16.9%	24.5%						
AFR 2006						-3.8%	-1.5%	-3.9%	3.2%	15.8%	1.2%	2.9%	4.4%	7.5%	5.1%	25.2%	17.0%	12.5%	19.9%	23.3%					
AFR 2007							0.7%	-0.6%	3.8%	17.8%	3.5%	5.8%	8.0%	10.5%	7.3%	27.0%	17.5%	11.9%	17.9%	20.1%	23.7%				
AFR 2008								-2.9%	0.5%	13.5%	-1.1%	0.5%	1.7%	3.8%	0.5%	19.4%	11.1%	6.5%	12.8%	15.5%	19.8%	19.8%			
AFR 2009									4.3%	16.8%	1.6%	3.2%	4.2%	6.3%	2.8%	22.1%	13.5%	8.8%	15.4%	18.3%	22.8%	23.1%	35.4%		
AFR 2010										-9.6%	-18.9%	-10.6%	-6.2%	-2.4%	-4.3%	13.4%	5.8%	1.5%	7.8%	10.8%	15.1%	15.3%	26.6%	21.8%	
AFR 2011											-0.5%	0.4%	1.3%	3.2%	-0.2%	17.5%	8.5%	3.2%	8.7%	10.6%	14.0%	13.4%	23.7%	18.2%	22.9%
AFR 2012												-0.3%	0.3%	2.5%	-0.6%	17.4%	8.6%	3.5%	9.2%	11.2%	14.7%	14.3%	24.7%	19.3%	21.3%
AFR 2013													0.1%	1.3%	-1.9%	15.8%	7.1%	2.0%	7.6%	9.6%	13.1%	12.6%	23.0%	17.6%	30.4%
AFR 2014														0.4%	1.5%	20.5%	16.5%	11.0%	16.9%	19.0%	22.5%	21.8%	32.8%	26.8%	28.6%
AFR 2015															-2.7%	24.2%	15.7%	10.3%	15.9%	17.9%	21.3%	20.4%	31.1%	25.1%	26.6%
AFR 2016																10.3%	10.5%	8.1%	13.8%	15.8%	19.3%	18.6%	29.1%	23.1%	23.2%
AFR 2017																	1.8%	-2.8%	2.1%	4.8%	11.4%	15.1%	25.7%	19.8%	17.8%
AFR 2018																		0.1%	4.8%	5.3%	11.1%	10.4%	20.4%	14.5%	14.8%
AFR 2019																			1.7%	3.2%	6.4%	7.8%	17.3%	11.7%	12.2%
AFR 2020																				-1.0%	2.8%	2.3%	14.3%	9.0%	-0.7%
AFR 2021																					-7.2%	-6.0%	1.8%	-3.3%	-1.1%
AFR 2022																						-7.0%	0.9%	-3.3%	4.6%
AFR 2023																							7.1%	1.7%	-0.7%
AFR 2024																								0.9%	3.1%
																									1.4%

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

E. Methodology Strengths and Weaknesses and Suitability to the System (7610.0320, Subp. 1.F)

The Company's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads or new technology adoption. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook and capturing the historical and projected effects of energy efficiency. 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.

The Company’s econometric modeling process has two key strengths: it is both highly replicable, and adept at narrowing the list of potential models to only those that are most likely to produce quality results which allows more time for in-depth statistical testing and critical review of each model.

That said, there are some weaknesses to a combined “econometric/large customer load addition” approach. For instance, there is some subjectivity in the perceived likelihood of individual large customer load additions/losses since their magnitude or timing is difficult to estimate in a probabilistic way. To minimize subjectivity on the part of Minnesota Power, the Company utilizes information that has been publicly communicated by prospective customers in its scenario planning.

Minnesota Power is highly sensitive to large industrial customer decisions as large taconite, paper, and pipeline customers represent more than half of Minnesota Power’s system demand and energy sales at any given point in time. The Company addresses this potential for error by maintaining close contact with existing and potential customers to keep current on their plans.

F. Data Requirements (7610.0320, Subp. 1.F)

Data used in Minnesota Power’s forecast can be broadly categorized as follows:

- *Historical quantities of the variables to be forecast,* which consists of energy sales and customer counts for Minnesota Power’s defined customer classes, energy sales, and peak demand.

- *Regional Demographic and Economic data:*

    - *Duluth Metropolitan Statistical Area (“MSA”)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.

    - *Aggregate 13-County Minnesota Power service territory (“13-Co”)* consists of population, Gross Regional Product (a Regional GDP metric), sector-specific employment, and income metrics.

    - *Individual 13-County Minnesota Power service territory (“13-Co”)* consists of sector-specific employment and income metrics for each individual County.

- *Indicators of National economic activity* such as the Industrial Production Indexes ("IPI") or Macroeconomic indicators such as U.S. GDP or Unemployment.
- *Weather and related data* including heating degree days ("HDD"), cooling degree days ("CDD"), temperature, humidity, dew point, and wind speed.
- *Electricity and Alternative Fuel prices*, which includes the price of electricity, natural gas, and heating oil by sector for the Minnesota Power service territory.

II. Forecast Data Inputs & Adjustments

A. Forecast Database Inputs (7610.0320, Subp. 2.A)

Weather

Weather data for Duluth, Minnesota was collected for historical periods from the National Oceanic and Atmospheric Administration ("NOAA") and from Weather Underground ("WU").[2] Minnesota Power utilizes Monthly HDDs and CDDs in energy sales forecasting and peak-day weather conditions in peak demand forecasting.

Monthly total HDD and CDD are sourced from NOAA. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month. This results in the "per-day" series HDDpd and CDDpd.

Normalizing the series by transforming to a per-day unit allows for a more accurate estimate of the weather's impact on energy sales. The forecast assumes more than a twenty-year historical average for each month (Jan 2001 – Dec 2024).

Temperature, humidity, and wind-chill data used to model peak demand are derived from Schneider Electric. In previous forecasts, the Company has leveraged either NOAA or WU for daily or monthly-frequency values. The AFR 2025 forecast database features weather observations that are specific to the historical peak hour (i.e., the temperature, humidity, and wind-chill at the time of the peak). This closer alignment between the peak demands and the weather that induced them should produce a more accurate estimate of weather-sensitivity and a more accurate forecast of future peak demand.

[2] http://www.wunderground.com/.

Development of the historical weather series begins by establishing the date and time of historical monthly peaks. Weather observations for these date/times are then gathered and organized into a monthly-frequency weather series.

A Temperature-Humidity Index ("THI")[3] is utilized to consider the effect of heat and, when applicable, humidity on summer peaks. The THI is only applicable when temperatures exceed 75 degrees. A Wind-Chill ("WC") index[4] was also utilized to capture the cold temperatures and, when applicable, the cooling effects of wind speed. The WC index is only applicable when temperatures drop below 40 degrees and wind speeds are greater than 3 miles per hour.

IHS Global Insight

IHS Global Insight is the singular source for all economic and demographic outlooks used in Minnesota Power's load forecast.[5] A single source for National, Metropolitan Statistical Area ("MSA"), and County-level outlooks ensures internal consistency of forecast assumptions.

IHS Global Insights data development process begins with producing a national-level forecast. County-level and MSA data for Northeast Minnesota is then calculated through a "Top-down/Bottom-up" approach; the Minnesota Power area economy is modeled independently, considering unique local conditions, and is then linked to the national economy to ensure consistency across the national, regional, state, and MSA levels.

IHS Global Insight utilizes the most current historical data available from public data sources, which is updated frequently. These updates flow through IHS Global Insight's process to ultimately effect the historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

The frequency of the raw Duluth MSA and National-level economic data is quarterly, and interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Regional Economic Models, Inc. ("REMI")

Minnesota Power subscribes to the latest REMI Policy Insight version ("PI+") for northeastern Minnesota. This input/output econometric simulation software combines a national economic

[3] http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml.
[4] http://www.nws.noaa.gov/os/windchill/index.shtml.
[5] With the exception of two series that are derived from REMI: Population and GRP for the 13-County Planning Region.

outlook[6] with specified regional economic conditions to produce a forecast for a 13-County Planning Area such as employment by sector, population, economic output by sector, and Gross Regional Product ("GRP").

For AFR 2025, REMI was used to quantify the indirect economic effects of known and expected changes in regional employment (i.e., expansions and layoffs/closures) to produce an expected economic outlook for the region.

IHS Global Insight economic indicators for both 13-County Planning Area and the Duluth MSA are calibrated using the results of REMI's economic simulations. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Some indicators such as population and GRP are not provided by IHS Global Insight for the 13-County Planning area. These series are derived directly from REMI outputs and are of annual frequency. Interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Like IHS Global Insight, REMI relies on data from public sources that are subject to revision. These revised data inputs result in revised historical values for the economic and demographic indicators used in Minnesota Power's database.

Indexes of Industrial Production ("IPI" series)

The indexes of industrial production are measures of sector-specific production in a given month relative to a base year, 2017 in this case (that is, 2017 = 100). The indexes exhibit a high degree of correlation with Minnesota Power's historical industrial energy sales and are, therefore, ideal for forecasting future energy sales to the class.

The historical national-level IPI data were obtained from the Board of Governors of the Federal Reserve. The historical data is regularly revised to incorporate better data, better methods, and to update the base year. To capture these revisions, Minnesota Power updates the entire historical data series each year. These revisions are explained on the Federal Reserve's website.[7]

[6] Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook.
[7] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf.

Forecasts for each national-level IPI were developed from the projections of national-level economic indicators from IHS Global Insight, and are, therefore, consistent with all other AFR 2024 forecast assumptions. These macroeconomic drivers are used to model and forecast the national-level IPI series.

The historical Minnesota iron IPI was developed using actual iron ore production data from the U.S. Geological Survey website ("USGS").[8] The projected Minnesota iron IPI was developed by scaling the national-level Iron IPI forecast using an assumption of the industry's composition going forward. Minnesota now comprises about 83 percent of U.S. product, so the Minnesota iron IPI equals the national-level IPI x 0.83. The entire historical and forecast Minnesota iron IPI was then indexed to 2017 for consistency with past AFRs, the other IPI series used in AFR 2025, and the U.S. Federal Reserve's current standard index year.

Energy Prices

Estimates of future Minnesota Power rate changes are incorporated into the average electric price forecasts as generally indicative of the intention and anticipation of changes in the Company's rate structure and prices.

Average energy prices, history and forecast data, are from the Department of Energy ("DOE") and Energy Information Administration ("EIA"). The fuel types considered are electricity and natural gas. End-use class energy price data is categorized by DOE/EIA into residential, commercial, and industrial. DOE's Annual Energy Outlook ("AEO") is used for the forecast period. DOE provides historical energy price data for Minnesota, forecast energy price data for the West North Central ("WNC") region, and the national total. Minnesota Power's historical average electric price data are from the Company's FERC Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2017 base year GDP implicit price deflator ("IPD").

B. Forecast Adjustments (7610.0320, Subp. 2.B)

1. Adjustments to Raw Energy Use and Customer Count Data

Minnesota Power made a limited number of adjustments to internally developed data for AFR 2025, which fall into three general categories:

[8] https://minerals.usgs.gov/minerals/pubs/commodity/iron_ore/.

a. **Adjustments to raw customer count data for billing anomalies:** Minnesota Power's historical customer count and energy sales data contain a number of anomalous or missing observations that can affect modeling and resulting forecasts. Where there is a systemic shift (e.g., seasonal billing in residential customers count), Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are fewer than three consecutive anomalous observations, Minnesota Power adjusts the raw data prior to regression using straight-line interpolation. In general, an observation was considered anomalous if it varied by more than 0.5 percent from a straight-line-interpolated value.

b. **Adjustments to raw sales and peak demand data for large load additions and losses**: All adjustments to the historical database are described below in detail and organized by sector:

[TRADE SECRET DATA BEGINS

[redacted]



TRADE SECRET DATA ENDS]

2. Adjustments to Econometric Forecast

Minnesota Power's forecast scenario is the summation of the econometric model results and arithmetic adjustments for impacts which cannot be accurately modeled. These adjustments fall into the following categories:

a. **Net Load/Energy Added**: Exogenous adjustments for load added due to Distributed Solar Generation, Electric Vehicle impacts, new customers or expansion by existing customers, and lost load due to closure, loss of contract, or reduced industry operating levels. This variability and average operating levels are expected over the forecast period and are taken into account as a normalized adjustment to a representative level in the forecast. This adjustment includes all load added or lost on the system, regardless of how that load is met; "Net Load/Energy Added" accounts for any change

in load at the system level. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values.

b. Customer Generation: The demand on Minnesota Power system that is met by customer owned generation. Customer generation can fluctuate without clear economic causes, so this component of Minnesota Power system peak is removed to more accurately model demand for an econometric forecast. The process for this adjustment can be outlined in three steps:

- Remove Customer Generation from the historical peak series.
- Econometrically project a less volatile "FERC load coincident w/Monthly Minnesota Power System peak (MW)" monthly peak series.
- Arithmetically account for Customer Generation after forecasting.

c. Dual Fuel: Minnesota Power has a demand response program for residential and commercial customers. The impacts of historical interruptions are assumed to be inherent in the forecast since curtailments affected historical monthly peak demand. Post-regression adjustments for dual fuel would produce an artificially low peak demand forecast. Minnesota Power will account for dual fuel interruptions as a resource and not as an adjustment to the load forecast.

d. Electric Vehicles: There are two components of the Electric Vehicle (EV) energy forecast: 1) The EV saturation rate of the total light-weight vehicles in Minnesota Power service territory and 2) the energy requirements per vehicle.

First, Minnesota Power estimated its current EV saturation rate of all light, medium, and heavy-duty vehicles in its service territory. Currently, there are 770 known light-weight, 19 medium-duty, and 7 heavy-duty electric vehicles in Minnesota Power's service territory,[9]. This equates to a 0.37 percent saturation rate of the total light-weight vehicles, 0.25% of total medium-duty vehicles, and 0.33% to total heavy-duty vehicles in Minnesota. To date, this saturation rate trails the national average electric vehicle adoption rate by about seven years for light and heavy-weight and eight years for

9 https://mn.gov/puc/activities/economic-analysis/electric-vehicles/

medium-weight vehicles. The Company then identified an updated publicly available forecast that considers recent industry trends and legislative action that incentivizes EVs. The EV adoption rate forecast for the Minnesota Power service territory follows Goldman Sachs's projected national adoption rate,[10] but lagged by about seven years. The Company attributes this lag in adoption to issues of income, population density/cost-efficiency of commercial charging station locations, and reduced efficiency in cold-weather. The annual saturation rate outlook is then multiplied by the estimated number of light, medium and heavy-duty vehicles in Minnesota Power's service territory [11] to estimate the total number of EVs.

The annual EV energy requirements forecast was calculated by multiplying the EV count and an estimate of per-unit energy requirements, which the Company assumes is about 2,800 kWh per year, 6.0 kWh per year, and 96.6 kWh per year for light, medium, and heavy-duty EVs respectively. This kWh per year estimate is based off a weighted average of the top three electric vehicles, in their respective weight class, in MP service territory and their respective energy usage. The Company also leveraged regional temperature information to impart a seasonal (i.e., monthly) distribution to the overall annual EV energy requirements estimates.

Identifying the impact of EV charging on monthly peak demand requires information on charging patterns/characteristics – i.e., how/when customers will tend to charge their vehicles. A National Renewable Energy Laboratory ("NREL") value assessment study of electric vehicles[12] contained modeled EV charging patterns for several customer types. For the purposes of determining EV charging load coincident with the system peak demand, Minnesota Power assumed the charging profile representative of level 1 charging, at a -single-family dwelling, with *no* Time of Use ("TOU") restriction or rate.

Under the AFR 2025 expected scenario, Minnesota Power customers own about 90,500 light-weight, 2,950 medium-duty, and 940 heavy-duty EVs (approximately 42.5%, 37.1%, and 42.5% saturation rate of light, medium, and heavy-duty vehicles

10 https://www.goldmansachs.com/intelligence/pages/electric-vehicles-are-forecast-to-be-half-of-global-car-sales-by-2035.html#:~:

11 Count of Standard Residential and All Electric accounts – excludes Dual Fuel and Controlled Access to avoid double counting and inflating the estimate of households served.

respectively in Minnesota Power service territory) by 2039, and the added energy requirements from post-2023 EV adoption increases to about 350,000 MWh total. This level of EV ownership would increase summer peak coincident demand by about 45 MW and winter peak demand by 131 MW.

e. **Distributed Generation** ("DG"): The process of forecasting DG solar generation involves two separate assumptions: 1) the rate of adoption (i.e., number of new installations each year), and 2) the average size of those new installations. Minnesota Power continued to use the following methodology for the rate of adoption to use the publicly available US Energy Information Administrations distributed residential solar generation forecast for AFR 2025. The average size (capacity) of new installations in the forecast timeframe is assumed as a simple historical average of installation size by class. Minnesota Power then calculated the estimated impact of new DG solar on energy sales by converting the capacity series (kW) to an energy series (kWh) using an 11 percent capacity factor assumption for new distributed installations.

   Identifying the impact of DG solar on the monthly peak demand outlook involves calculating the amount of solar generation that is likely during a specific month's likely peak time (i.e., historical median peak hour) using a simulated hourly solar production curve. Minnesota Power typically peaks at 6:00 or 7:00 PM (well after sunset) in winter months, so DG solar at the time of the peak is zero percent and projected winter peaks are not reduced. In summer months, Minnesota Power has historically peaked at 3:00 or 4:00 PM when DG solar is on average 55 percent of installed capacity (the effective load carrying capacity or ELCC is 0.55).

III. Overview of Key Assumptions (7610.0320, Subp. 3)

A. National Economic Assumptions

The national economic outlook is derived from IHS Global Insight and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales.

B. Regional Economic Assumptions

The Regional Economic Model provided by REMI is calibrated to the geographic area additively defined as 13 counties, 12 counties in Minnesota (Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena) and one county in Wisconsin (Douglas). This is referred to as the "13-County Planning Area." Minnesota Power expanded its database to include economic and demographic indicators at the Metropolitan Statistical Area level (this includes St. Louis and Carlton counties in Minnesota and Douglas County in Wisconsin).

The 13-County Planning Area's Gross Regional Product is forecasted to average 1.5 percent per-year growth in the forecast timeframe whereas the Duluth MSA product averages 2.0 percent per-year in the forecast timeframe. Population for the 13-County Planning Area grows at about 0.3 percent in the forecast timeframe and the Duluth MSA area population remains consistent with current levels.

IV. Subject of Assumption (7610.0320, Subp. 4)

Section 7610.0320, Subpart 4, lists specific assumptions to be discussed. The following list contains the discussion of each assumption and Minnesota Power's response.

- Assumptions made regarding the availability of alternative sources of energy.
    - *Minnesota Power makes no assumptions regarding the availability of alternative sources of energy*.
- Assumptions made regarding expected conversion from other fuels to electricity or vice versa.
    - *Minnesota Power makes no assumptions regarding the expected conversion from one fuel source to another*.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
    - *See Section II.A.*
- Assumptions made in arriving at the data requested (historical reporting).
    - *Minnesota Power makes no such assumptions*.

- Assumptions made regarding the effect of existing energy conservations programs under Federal or State legislation on long-term electricity demand and assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Federal or State legislation.

  Minnesota Power uses energy efficiency as an input variable to the regression models, referred to as "EE as RHS var" or "Energy Efficiency as a Right-Hand Side Variable." The "EE as RHS var" methodology has several advantages over other common energy efficiency forecasting methodologies:

  - *Avoids double-counting energy efficiency impacts in the forecast timeframe.*
  - *Accounts for historical and projected conservation resulting from both Company programs and organic, customer-driven efforts.*
  - *Leverages raw sales data in regression modeling: sales data are not adjusted for conservation impacts prior to modeling.*
  - *Doesn't require after-the-fact adjustments to econometric outputs: the energy sales forecasts already contain the effects of energy efficiency.*

  An "Energy Efficiency" variable explains recent trends in customer consumption that cannot be explained by economic, demographic, or weather effects. Further, this method allows the Company to quantify the volume of energy efficiency embedded in the load forecast.

  Development of the "Energy Efficiency" variable began by gathering savings data for each retail customer class, Superior Water Light and Power, and the Company's 14 Minnesota municipal customers. Incremental (i.e., first year) savings data for the historical and forecast timeframe was assembled from a number of sources. Historical incremental savings data for Minnesota Power was obtained from the Company's past annual energy efficiency compliance filings, Minnesota Municipal customers' historical savings information was obtained from CIP results filed with the Department of Commerce.[13] Superior Water Light and Power provided its own historical savings information to Minnesota Power.

  Forecast assumptions for Minnesota Power's residential and commercial savings were derived from the Company's most recent preliminary estimates of achieved and

[13] Historical achievements filed in Docket No. E-999/PR-22-24

energy savings assumptions beyond 2024, were based on the Company's 2024-2026 Triennial ECO Plan Filing.

For each of the retail classes and resale customers, the Company cumulated the historical and projected incremental savings to produce a "cumulative energy savings" series.[14] This cumulative series is the optimal variable format/definition for modeling energy sales. A cumulative savings metric represents the lasting impacts of conservation programs by aggregating or cumulating the savings from all past conservation measures. Minnesota Power used an annual "Energy Efficiency" variable in regression models for sales to the residential, commercial, and public authority classes, as well as three of the Company's 14 resale customers modeled in AFR 2025.

- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
    - *Minnesota Power makes no assumptions regarding current and future saturation levels of appliances and electric space heating*.

V. Coordination of Forecasts with Other Systems (7610.0320, Subp.5)

Minnesota Power is a member of the Midwest Reliability Organization ("MRO"), Midcontinent Independent System Operator ("MISO"), Edison Electric Institute ("EEI"), and other trade associations. While each member of these groups independently determines its power requirements, periodic meetings are held to share information and discuss forecasting techniques and methodologies.

VI. Load Growth Forecast Planning Scenario

U.S. electric demand is expected to grow over the next decade due to policy focused on sustainability through electrification, onshoring of industrial manufacturing, and expansion in data processing capabilities. Minnesota Power is currently seeing interest in electrification and data centers and is including a scenario in this AFR for substantial load growth aligned with its most

[14] Using internal estimates of Minnesota Power's past programs' life of measures. A Life of Measure (LoM) is the approximate time a conservation measure will reduce energy consumption. Most conservation measures have a 10- to 20-year life. A portfolio from any particular program year will contain measures that end earlier than others, so the overall impact of measures implemented in a program year will fade over time.

recent Integrated Resource Plan representative of the possible opportunities for expansion of these technologies and customers in the region. Minnesota Power will continue to work with our current and new customers and update the forecast and associated planning processes as needed.

Electrification

In 2021, the Energy Conservation and Optimization Act was signed into law. ECO allows for streamlining of efficient fuel switching, which includes technologies such as air source heat pumps to replace fossil fueled heating technologies, supporting the probability of increased electricity consumption while homes and businesses reduce overall fossil fuel usage and carbon dioxide emissions.

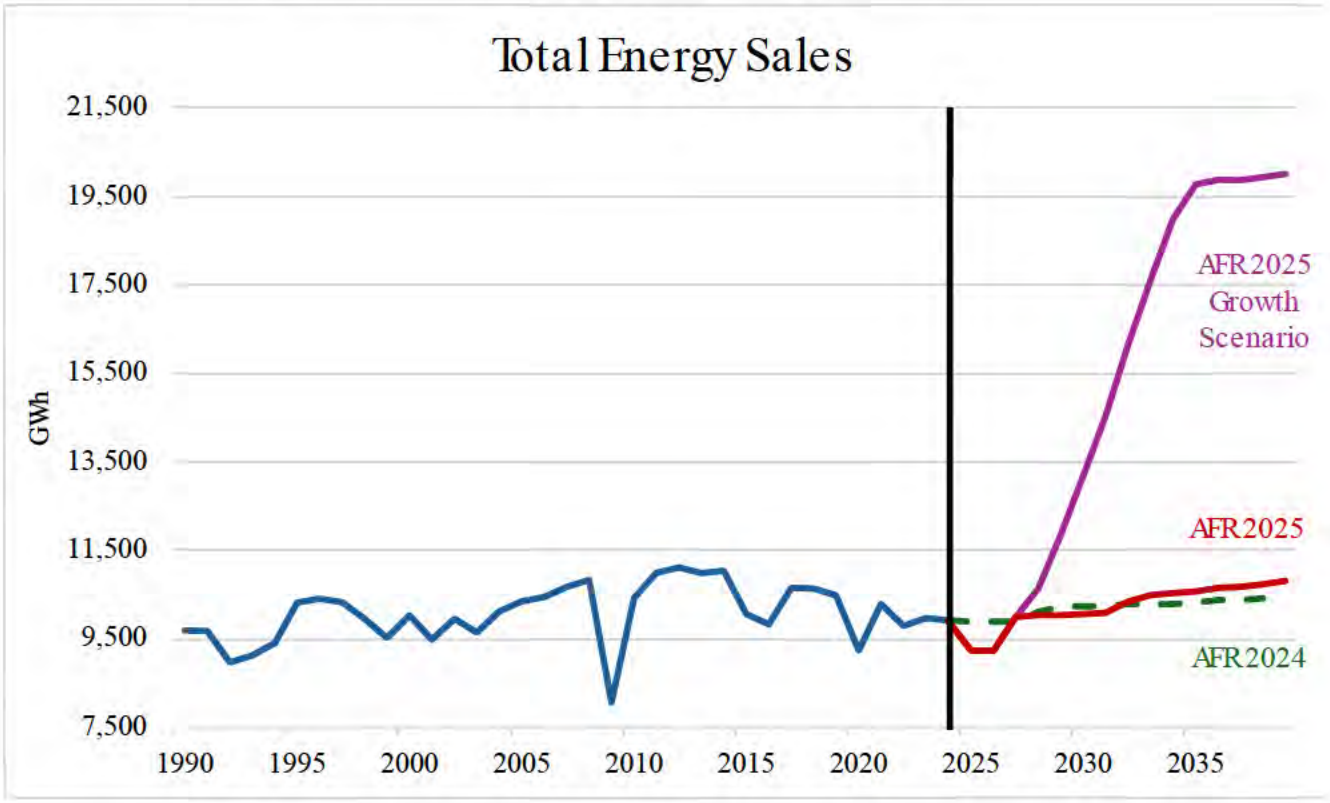
Data Centers

Energy consumption by data centers in the United States is expected to double by 2030 according to a recent study by the Electric Power Research Institute ("EPRI").[15] Trends in computing are shifting towards Artificial Intelligence ("AI") and machine learning, as well as the increasing reliance on digital services that require data processing and storage, driving the expansion of new data centers being built with capacities ranging from 100 MW to over 1,000 MW in locations with interconnection capabilities for large loads. These loads are typically very high load factor facilities requiring high energy density to support their operation.

15 https://www.epri.com/research/products/3002028905.

Below, for the Load Growth Forecast Planning scenario, the total energy sales graph displays the base AFR 2025 results, along with the AFR 2025 load growth scenario.

Figure 23 Total Energy Sales for Load Growth Forecast Planning Scenario



The table below shows the peak forecast results based on the load growth forecast planning scenario included in the AFR 2025 filing.

Figure 24 Peak Forecast (MW) for the Load Growth Forecast Planning Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak		
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*
2000					1,469	1,503	242	281	1,711	1,784	*1,784*
2001					1,383	1,421	150	175	1,533	1,595	*1,595*
2002					1,464	1,455	165	287	1,629	1,742	*1,742*
2003					1,342	1,496	310	250	1,651	1,746	*1,746*
2004					1,449	1,533	218	250	1,667	1,783	*1,783*
2005					1,535	1,555	255	238	1,789	1,793	*1,793*
2006					1,584	1,534	237	232	1,821	1,766	*1,821*
2007					1,582	1,584	246	241	1,828	1,825	*1,828*
2008					1,529	1,575	228	203	1,757	1,777	*1,777*
2009					1,200	1,369	211	246	1,411	1,615	*1,615*
2010					1,591	1,599	140	190	1,732	1,789	*1,789*
2011					1,573	1,630	173	150	1,746	1,780	*1,780*
2012					1,603	1,605	186	168	1,789	1,773	*1,789*
2013					1,645	1,589	135	162	1,781	1,751	*1,781*
2014					1,620	1,637	184	180	1,805	1,818	*1,818*
2015					1,442	1,461	148	87	1,589	1,547	*1,589*
2016					1,453	1,520	157	173	1,610	1,693	*1,693*
2017					1,538	1,594	150	195	1,688	1,789	*1,789*
2018					1,585	1,557	139	150	1,724	1,707	*1,724*
2019					1,560	1,588	108	99	1,668	1,687	*1,687*
2020					1,410	1,548	78	97	1,487	1,646	*1,646*
2021					1,553	1,556	73	108	1,625	1,663	*1,663*
2022					1,484	1,456	49	94	1,533	1,550	*1,550*
2023					1,551	1,529	63	89	1,614	1,618	*1,618*
2024	1,372	1,420	0	57	**1,372**	**1,477**	54	122	**1,426**	**1,599**	**1,599**
2025	1,414	1,422	53	58	**1,467**	**1,480**	122	122	**1,589**	**1,602**	**1,602**
2026	1,414	1,423	52	93	**1,466**	**1,516**	122	122	**1,588**	**1,638**	**1,638**
2027	1,416	1,424	139	220	**1,555**	**1,645**	122	122	**1,677**	**1,766**	**1,766**
2028	1,417	1,426	210	369	**1,628**	**1,795**	122	122	**1,749**	**1,917**	**1,917**
2029	1,419	1,428	356	530	**1,775**	**1,958**	122	122	**1,897**	**2,080**	**2,080**
2030	1,421	1,430	514	694	**1,935**	**2,124**	122	122	**2,057**	**2,246**	**2,246**
2031	1,422	1,430	673	866	**2,095**	**2,296**	122	122	**2,217**	**2,418**	**2,418**
2032	1,423	1,431	867	1,080	**2,290**	**2,511**	122	122	**2,412**	**2,633**	**2,633**
2033	1,424	1,432	1,042	1,254	**2,466**	**2,686**	122	122	**2,587**	**2,808**	**2,808**
2034	1,424	1,433	1,205	1,358	**2,629**	**2,791**	122	122	**2,751**	**2,913**	**2,913**
2035	1,425	1,434	1,297	1,374	**2,722**	**2,808**	122	122	**2,844**	**2,930**	**2,930**
2036	1,426	1,435	1,301	1,391	**2,726**	**2,826**	122	122	**2,848**	**2,948**	**2,948**
2037	1,426	1,437	1,304	1,409	**2,731**	**2,846**	122	122	**2,852**	**2,967**	**2,967**
2038	1,428	1,440	1,308	1,428	**2,736**	**2,868**	122	122	**2,858**	**2,989**	**2,989**
2039	1,431	1,407	1,319	1,436	**2,750**	**2,843**	122	122	**2,872**	**2,965**	**2,965**

VII. Load Reduction Forecast Planning Scenario

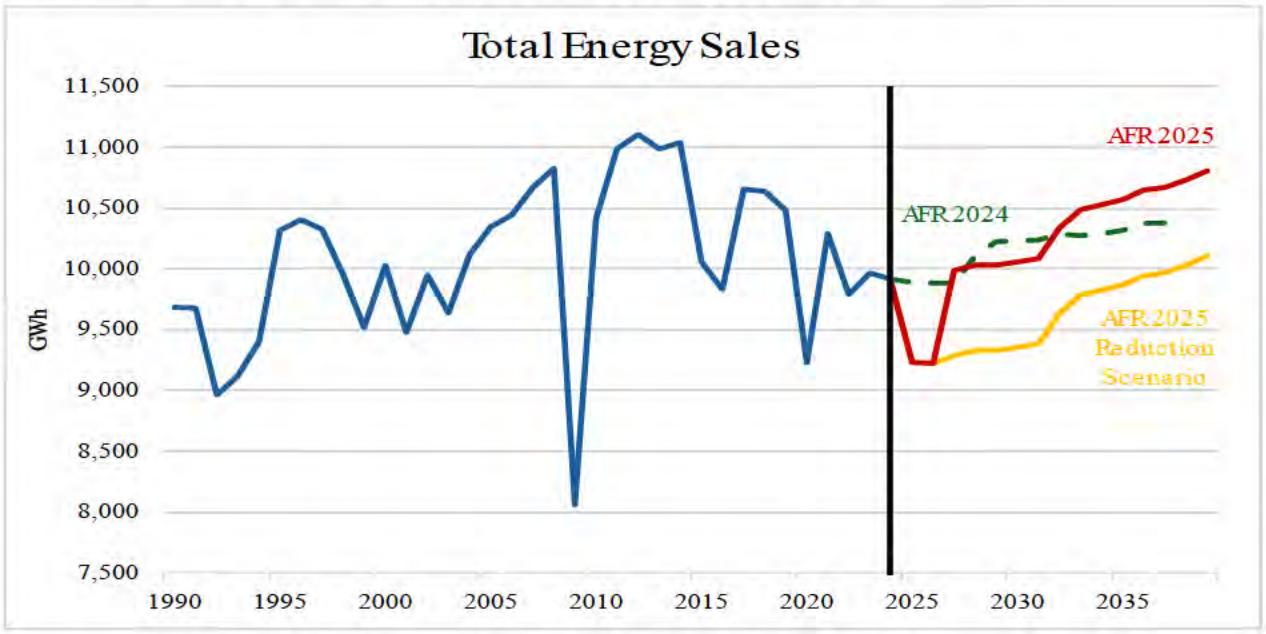
The mining industry in Northern Minnesota, particularly on the Iron Range, is known for its volatility, influenced by various factors. Due to the uncertainty of future mining load, Minnesota Power is including a load reduction scenario in this AFR tied to uncertainty at Cleveland-Cliffs, Mesabi Metallics, and New Range. At Cleveland-Cliffs there have been recent announcements to lay off over 600 employees at both their Hibbing Taconite and Minorca mining facilities, along with citing that Hibbing Taconite's mine will have an ore shortage[16]. Additionally, Mesabi Metallics is currently constructing a mining facility that is 80 percent complete and included in the Minnesota Power expected forecast plan through its wholesale service agreement with Nashwauk Public Utilities[17]. It is important to plan for a range of customers' load since economic, financial, and construction challenges may occur. Finally, load growth tied to customers face unpredictable hurdles such as environmental, permits, and falling copper prices. Minnesota Power will continue to work with our current and new large power customers and update the forecast and associated planning processes as needed.

16 https://minnesotareformer.com/2025/03/20/cleveland-cliffs-set-to-layoff-630-steelworkers-at-minorca-hibbing-taconite/#:~:text=The%20bigger%20concern%20around%20HibTac,long%2Dterm%20picture%20is%20unclear.

17 https://www.northernnewsnow.com/2025/06/20/mesabi-metallics-expects-open-taconite-mine-early-2026/

Below, for the Load Reduction Forecast Planning scenario, the total energy sales graph displays the base AFR 2025 results, along with the AFR 2025 load reduction scenario.

Figure 25 Total Energy Sales for Load Reduction Forecast Planning Scenario



The table below shows the peak forecast results based on the load reduction forecast planning scenario included in the AFR 2025 filing.

Figure 26 Peak Forecast (MW) for the Load Reduction Forecast Planning Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak		
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*
2000					1,469	1,503	242	281	1,711	1,784	*1,784*
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2010					1,591	1,599	140	190	1,732	1,789	*1,789*
2011					1,573	1,630	173	150	1,746	1,780	*1,780*
2012					1,603	1,605	186	168	1,789	1,773	*1,789*
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2017					1,538	1,594	150	195	1,688	1,789	*1,789*
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2020					1,410	1,548	78	97	1,487	1,646	*1,646*
2021					1,553	1,556	73	108	1,625	1,663	*1,663*
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2023					1,551	1,529	63	89	1,614	1,618	*1,618*
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2025	1,414	1,422	53	58	**1,467**	**1,480**	122	122	**1,589**	**1,602**	**1,602**
2026	1,414	1,423	52	31	**1,466**	**1,454**	122	122	**1,588**	**1,576**	**1,588**
2027	1,416	1,424	58	67	**1,474**	**1,491**	122	122	**1,596**	**1,613**	**1,613**
2028	1,417	1,426	57	69	**1,474**	**1,496**	122	122	**1,596**	**1,617**	**1,617**
2029	1,419	1,428	56	73	**1,476**	**1,501**	122	122	**1,597**	**1,622**	**1,622**
2030	1,421	1,430	56	78	**1,477**	**1,508**	122	122	**1,599**	**1,629**	**1,629**
2031	1,422	1,430	56	89	**1,479**	**1,520**	122	122	**1,601**	**1,641**	**1,641**
2032	1,423	1,431	91	143	**1,514**	**1,574**	122	122	**1,636**	**1,696**	**1,696**
2033	1,424	1,432	104	156	**1,528**	**1,588**	122	122	**1,650**	**1,710**	**1,710**
2034	1,424	1,433	107	171	**1,532**	**1,605**	122	122	**1,653**	**1,726**	**1,726**
2035	1,425	1,434	111	188	**1,535**	**1,622**	122	122	**1,657**	**1,743**	**1,743**
2036	1,426	1,435	114	204	**1,540**	**1,640**	122	122	**1,661**	**1,761**	**1,761**
2037	1,426	1,437	118	223	**1,544**	**1,659**	122	122	**1,666**	**1,781**	**1,781**
2038	1,428	1,440	122	240	**1,550**	**1,680**	122	122	**1,671**	**1,802**	**1,802**
2039	1,431	1,415	126	265	**1,556**	**1,680**	122	122	**1,678**	**1,802**	**1,802**

STATE OF MINNESOTA)
)ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

I, Amy M. Honkala of the City of Duluth, County of St. Louis, State of Minnesota, hereby certify that on the 1st day of August, 2025, I electronically filed a true and correct copy of Minnesota Power's **Annual Compliance Filing Docket number E999/PR-25-11** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on eDocket's Official Service List for this Docket were served as requested.



Amy M. Honkala

PUBLIC DOCUMENT

TRADE SECRET DATA EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - LARGEST CUSTOMER LIST
CY 2024

WHEN E-FILING THIS FORM, IT SHOULD BE UPLOADED AS TRADE SECRET

ENTITY ID#	68
REPORT YEAR	2024

UTILITY DETAILS

UTILITY NAME	Minnesota Power Co
STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-722-5642 x3865

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[TRADE SECRET DATA BEGINS

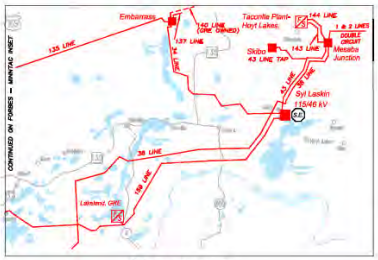
ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2024 MWH
[redacted]						

THIS LARGEST CUSTOMER LIST SHOULD BE SUBMITTED TO COMMERCE AS AN EXCEL WORKBOOK
DO NOT SUBMIT THIS LARGEST CUSTOMER LIST AS A PDF OR IN ANY OTHER FORMAT.

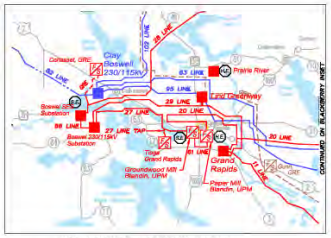
PUBLIC DOCUMENT

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[redacted]						



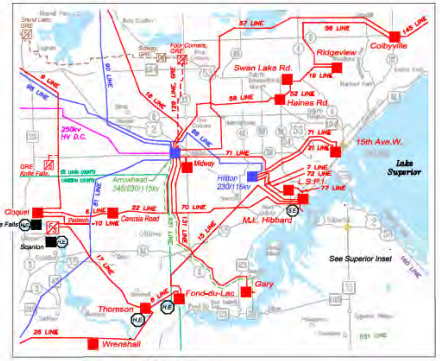
3 SYL LASKIN INSET



4 CLAY BOSWELL - GRAND RAPIDS INSET



5 NASHWAUK INSET



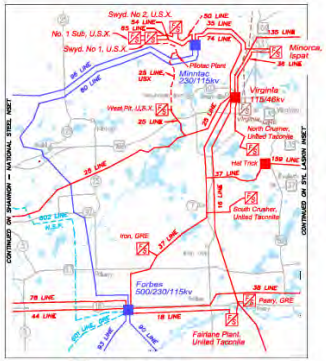
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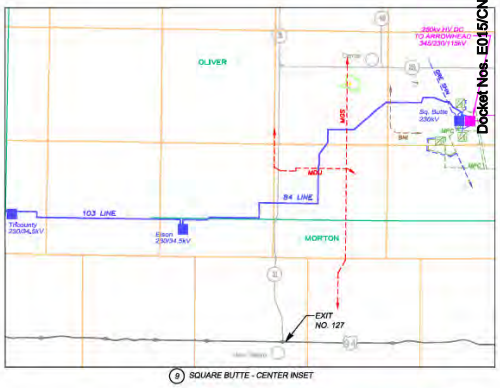
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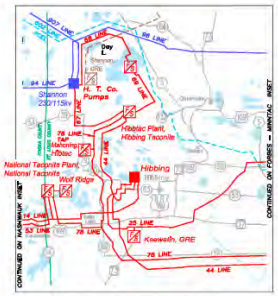
6 ZEMPLE - DEER RIVER



2 FORBES - MINNTAC INSET



9 SQUARE BUTTE - CENTER INSET



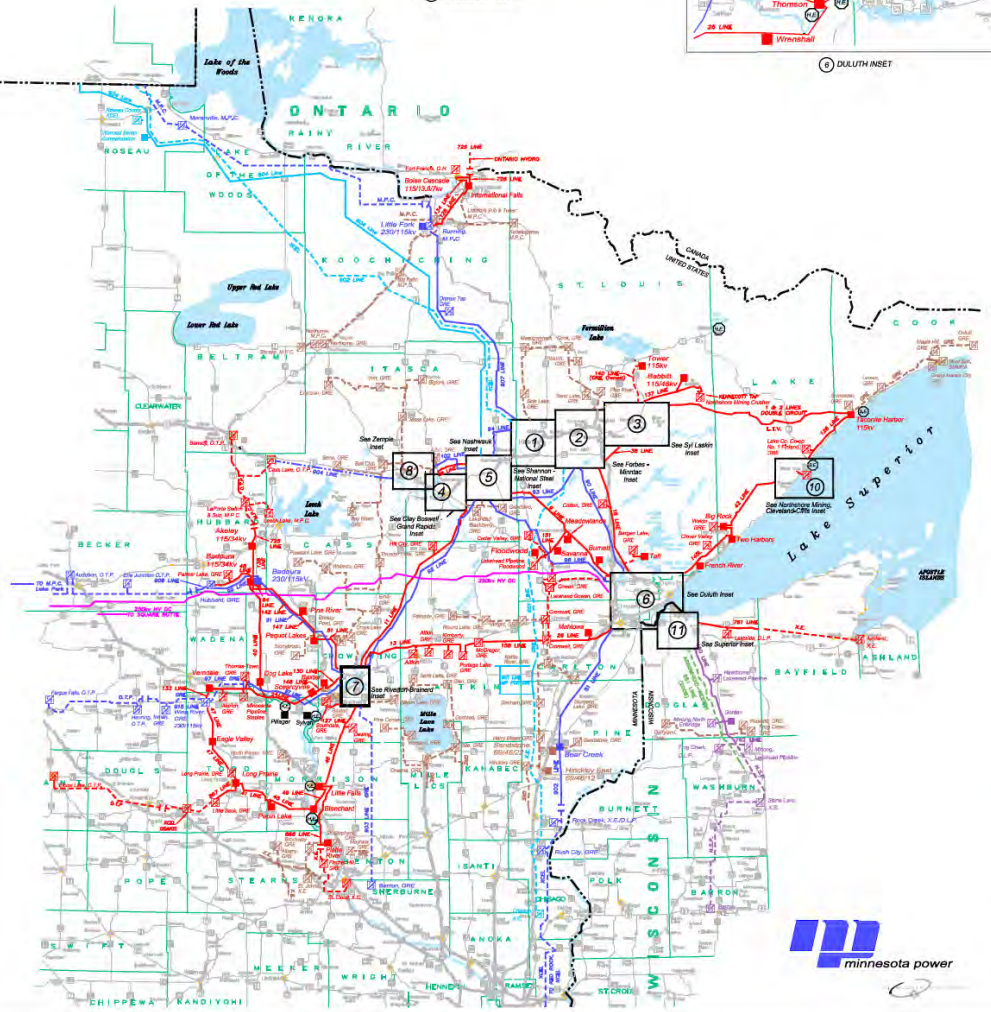
1 SHANNON - NATIONAL STEEL INSET



10 NORTHSHORE MINING, CLEVELAND-CLIFFS



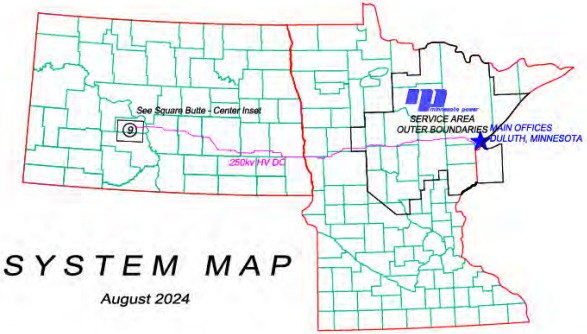
11 SUPERIOR INSET



LEGEND

- 69KV TRANSMISSION
- 115KV TRANSMISSION
- 161KV TRANSMISSION
- 230KV – AC TRANSMISSION
- 250KV HV DC TRANSMISSION
- 345KV TRANSMISSION
- 500KV TRANSMISSION
- FOREIGN TRANSMISSION*
- CapX TRANSMISSION*

- 69KV SUBSTATION
- 115KV SUBSTATION
- 161KV SUBSTATION
- 230KV SUBSTATION
- 345KV SUBSTATION
- 500KV SUBSTATION
- < 69KV SUBSTATION
- FOREIGN SUBSTATION*
- STEAM ELECTRIC STATION
- HYDRO ELECTRIC STATION
- * COLOR INDICATES VOLTAGE



SYSTEM MAP

August 2024

TITLE PAGE

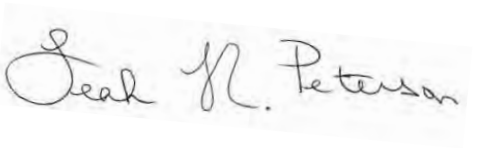
MINNESOTA POWER

ELECTRIC RATE BOOK

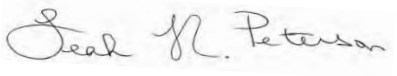
This book contains Minnesota Power's retail rates and related information per the Minnesota Department of Public Service Initial Filing Instructions issued November 18, 1974 and is the Company's official Electric Rate Book on file with the Minnesota Department of Commerce.

The Minnesota Power official responsible for this rate book is:

Leah N. Peterson
Manager - Customer Analytics



Authorizing Signature:



Approved by:

Leah N. Peterson
Manager - Customer Analytics

	Schedule	Page(s)
Section I		
Title Page		1.0
Table of Contents		2.0 - 2.2
Section II – Reserved for Future Use		1.0
Section III – Reserved for Future Use		1.0
Section IV – Reserved for Future Use		1.0
Section V		
RESIDENTIAL RATE SCHEDULES		
Residential Service		
– General	20	1.0 - 1.2
– Space Heating	22	1.0 - 1.2
– Seasonal Residential	23	1.0 - 1.2
Residential Dual Fuel Interruptible		
Electric Service	21	5.0 - 5.3
Residential Fixed Off-Peak Service	24	7.0 - 7.2
Residential Electric Vehicle Service	28	8.0 - 8.2
COMMERCIAL AND INDUSTRIAL RATE SCHEDULES		
General Service	25	10.0 - 10.3
Commercial Electric Vehicle Public Charging Service	29	11.0 - 11.2
Commercial Electric Vehicle Fleet Charging Service	30	12.0 - 12.2
Company-owned Electric Vehicle Service Equipment	31	13.0 - 13.2
Commercial/Industrial Dual Fuel		
Interruptible Electric Service	26	16.0 - 16.4
Commercial/Industrial Fixed Off-Peak Service	27	17.0 - 17.2
Large Light and Power Service	75	22.0 - 22.2
Competitive Rate Schedule –		
Large Light and Power Service	73	23.0 - 23.2
Large Power Service	74	24.0 - 24.6
Non-Contract Large Power Service	78	25.0 - 25.4
Competitive Rate Schedule –		
Large Power Service	79	26.0 - 26.1
Outdoor and Area Lighting Service	76 - 77	37.0 - 37.4
GOVERNMENTAL RATE SCHEDULES		
Street and Highway Lighting Service		
– Highway Lighting Service	80	46.0 - 46.5
– Overhead Street Lighting Service	83	46.0 - 46.5
– Ornamental Street Lighting Service	84	46.0 - 46.5
RIDERS TO RATE SCHEDULES		
Rider for Fuel and Purchased Energy Charge	Rider	50.0 - 50.3
Temporary Service Rider to		
General Service Schedules	Rider	51.0
Sports Field Lighting Rider to		
General Service Schedules	Rider	52.0

Rider for Multiple Meter Service	Rider	53.0
Rider for Expedited Billing Procedures	Rider	54.0 - 54.4
Rider for Schools	Rider	56.0
Rider for Revenue Credit from Non-Contract Large Power Service	Rider	57.0
Rider for City of Duluth Franchise Fee	Rider	59.0
Rider for Parallel Generation	Rider	60.0 - 60.9
Rider for Standby Service	Rider	61.0 - 61.9
Rider for Fond du Lac Reservation Business License Fee	Rider	64.0
Rider for Conservation Program Adjustment	Rider	66.0 - 66.1
Rider for Non-Metered Service	Rider	67.0 - 67.1
Rider for General Service/Large Light and Power Interruptible Service	Rider	68.0 - 68.2
Rider for Large Power Incremental Production Service	Rider	69.0 - 69.3
Rider for Released Energy	Rider	70.0 - 70.1
Rider for Voluntary Energy Buyback	Rider	72.0 - 72.2
Rider for Voluntary Renewable Energy	Rider	73.0 - 73.1
Rider for City of Long Prairie Franchise Fee	Rider	77.0
Rider for City of Little Falls Franchise Fee	Rider	78.0
Rider for City of Hermantown Franchise Fee	Rider	79.0
Rider for City of Park Rapids Franchise Fee	Rider	80.0
Rider for City of Aurora Franchise Fee	Rider	81.0
Rider for Distributed Generation Service	Rider	82.0 - 82.3
Rider for Renewable Resources	Rider	85.0
Rider for Transmission Cost Recovery	Rider	86.0
Rider for City of Nashwauk Franchise Fee	Rider	88.0
Rider for Foundry - Forging and Melting Customers	Rider	89.0
Pilot Rider for Large Light & Power Time-of Use Service	Rider	90.0 - 90.1
Rider for Customer Affordability of Residential Electricity (CARE)	Rider	92.0 - 92.3
Rider for City of Silver Bay Franchise Fee	Rider	94.0
Rider for City of Hoyt Lakes Franchise Fee	Rider	95.0
Rider for Solar Energy Adjustment	Rider	96.0 - 96.1
Pilot Rider for Community Solar Garden	Rider	97.0 - 97.2
Rider for Backup Generation Service	Rider	99.0 - 99.3
Rider for Business Expansion Incentive	Rider	100.0 - 100.2
Rider for City of Upsala Franchise Fee	Rider	101.0
Rider for Large Power Demand Response Service	Rider	103.0 - 103.2
Rider for Remote Service Reconnection	Rider	104.0
Rider for City of Pequot Lakes Franchise Fee	Rider	105.0
Rider for Renewable Resources-Solar Factor Adjustment	Rider	106.0
Rider for Advanced Metering Infrastructure (AMI) Opt-out	Rider	107.0 - 107.1
Rider for Residential Time-of-Day Service	Rider	109.0 - 109.1
Rider for City of Sandstone Franchise Fee	Rider	110.0
Rider for Capacity Revenue and Expense Adjustment	Rider	111.0 - 111.2
Rider for Voluntary Renewable Energy Large Customers	Rider	112.0 - 112.1

Section VI

RULES AND REGULATIONS

Definitions of Classes of Customers		1.0
Residential Service Rules		2.0
Electric Service Regulations of Minnesota Power		3.0 - 3.24
Extension Rules		4.0 - 4.6
Budget Billing Plan		7.0

Section VII

STANDARD CONTRACTS AND AGREEMENTS

Application for Residential Electric		1.0
Service Electric Service Agreement		1.0

Section VIII – Reserved for Future Use 1.0

Section IX

Community-Based Energy Development (C-BED)	Original	1.0 - 1.2
SolarSense Customer Solar Program	Original	4.0 - 4.1
Pilot for Retail Company-owned Electric Vehicle Charging Service		5.0 - 5.1

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESIDENTIAL SERVICE

RATE CODES

Residential - General	20
Residential - Space Heating	22
Residential - Seasonal	23

APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations, and any applicable Riders. There is a maximum of one Residential – General or Residential – Space Heating service per customer.

A customer will be billed on the seasonal rate if the dwelling is typically occupied for 182 days or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$9.00	$15.00
All kWh (¢/kWh)	10.818¢	11.324¢

0 kWh to 600 kWh discount for eligible customers -4.329¢

Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

RESIDENTIAL SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. An eligible customer is defined as a customer who has average monthly usage that is less than or equal to the usage threshold of 1,000 kWh, along with being a low-income customer. A low-income customer is defined as eligible for the Low Income Home Energy Assistance Program ("LIHEAP") in Minnesota Power's billing system or a customer who has completed a self-declaration process. The qualification for the discount would be based on a monthly usage average using twelve months of historical usage.

11. Eligible customers will receive the discount for a one year time period, at which point average monthly usage will be re-calculated to determine the continued eligibility for the following year.

RESIDENTIAL SERVICE

12. Self-declaration for the low-income eligibility will require a renewal every two years in general and every four years for those on a fixed income.

13. The discount for eligible customers is applied to the first 600 kWh each month, as applicable.

14. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to the Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kilowatts (kW) or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers, or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)
Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.

Dual Fuel Plus
Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 1,000 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted for 20 hours per calendar day. In the event of a 20-hour interruption period, there will be a period of at least two hours before the next interruption period.

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge – Dual Fuel (standard)	
Small Service	7.989¢ per kWh
Large Service	7.989¢ per kWh

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

Energy Charge - Dual Fuel Plus	
Small Service	5.584¢ per kWh
Large Service	5.584¢ per kWh

Plus any applicable Adjustments.

Customers who have a qualified Air Source Heat Pump as approved by the company, may elect to be exempt from dual fuel interruptions from June through September and would pay the energy charge below.

Energy Charge	
All kWh (per kWh)	10.818¢

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. Interruption will normally occur at such times:

   (a) when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when the Company expects to incur a new system peak,
   (c) at such other times when, in the Company's opinion, system reliability is endangered,
   (d) when the Company performs necessary testing for certification of interruptibility of customers' loads.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

5. If Company is unable to disconnect with integrated disconnects in the meters, Company will provide and customer will install as directed by the Company, equipment to provide signals to control load. Customer must provide a continuous 120 volt AC power source at the Company's control point for operation of the Company's remote control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL FIXED OFF-PEAK SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 10 p.m. and 6 a.m. Central Prevailing Time (CPT) each day. Service is subject to the Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kW or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

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RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge	
Small Service (per kWh)	5.584¢
Large Service (per kWh)	5.584¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

RESIDENTIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

RESIDENTIAL FIXED OFF-PEAK SERVICE

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Where direct load control by meter is not available, customer's load shall be controlled by a switching device approved or supplied by the Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

To electric service for residential customers for the sole purpose of recharging electric vehicle(s) or battery powered equipment. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$6.00
Off-Peak Energy Charge	
All kWh (per kWh)	3.231¢
On-Peak Energy Charge	
All kWh (per kWh)	11.540¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The Residential Electric Vehicle Service load shall be separately served and metered and shall at no time be connected to facilities serving Customer's other loads. To be eligible for this rate, Customer must also take Residential Service under the General, Space Heating, or Seasonal rate.

2. The total connected off-peak load shall not exceed 100 kW.

3. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

5. On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$15.00
Energy Charge for all kWh	9.919¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$15.00
Demand Charge for all kW	$6.50
Transmission Demand for all kW	$4.03
Energy Charge for all kWh	6.931¢

Plus any applicable Adjustments.

GENERAL SERVICE

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2,500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

Customers whose monthly demand has been less than 10 kW during the past 12-month period and whose monthly consumption has not exceeded 2,500 kWh in three or more consecutive months during the same 12-month period will be identified and the 12-month history of such customer's kW and kWh requirements are reviewed. After review, where appropriate, a rate change will be made to a non-demand general service rate.

GENERAL SERVICE

All customers exceeding the demand threshold criteria are required to be moved to the demand rates. Those not reaching the criteria are eligible to be removed from the demand rates.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

RATE CODES

29

APPLICATION

Available to Commercial and Industrial customer's electric service requirements for electric vehicle loads that serves public charging including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.931¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the total demand charges, including Transmission Demand Charge, exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Transmission Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the demand charges, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

RATE CODES

30

APPLICATION

Available to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge for On-Peak ($/kW)	$6.50
Energy Charge for all kWh	6.931¢
Transmission Demand Charge ($/kW) On-Peak Transmission Demand	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

RATE CODES

31

APPLICATION

Available to Company-owned Electric Vehicle Service Equipment which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.931¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the total demand charges, including Transmission Demand Charge, exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Transmission Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the demand charges, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to the Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kilowatts (kW) or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers, or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)

Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.

Dual Fuel Plus

Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 1,000 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted for 20-hours per calendar day. In the event of a 20-hour interruption period, there will be a period of at least two hours before the next interruption period.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge – Dual Fuel (standard)	
Small Service	7.949¢ per kWh
Large Service-Low Voltage	7.949¢ per kWh
Large Service-High Voltage	7.812¢ per kWh
Energy Charge – Dual Fuel Plus	
Small Service	5.551¢ per kWh
Large Service-Low Voltage	5.551¢ per kWh
Large Service-High Voltage	5.435¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

Customers who have a qualified Air Source Heat Pump as approved by the company, may elect to be exempt from dual fuel interruptions from June through September and would pay the energy charge below.

Energy Charge	
All kWh (per kWh)	9.919¢ per kWh

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

3. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) when, in the Company's opinion, the reliability of the system is endangered, or
   (d) when the Company performs necessary testing of interruptibility of customer's loads.

   Interruptions shall normally occur for reliability-related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. If Company is unable to disconnect with integrated disconnects in the meters, Company will provide and customer will install as directed by the Company, equipment to provide signals to control load. Customer must provide a continuous 120 volt AC power source at the Company's control point for operation of the Company's remote control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

7. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, as specified in Dual Fuel program options above.

8. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Midcontinent Independent System Operator (MISO) in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

   (a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer's service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 10 p.m. and 6 a.m. Central Prevailing Time (CPT) each day. Service is subject to the Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kW or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge	
Small Service - Low Voltage	5.551¢ per kWh
Large Service - Low Voltage	5.551¢ per kWh
Large Service - High Voltage	5.435¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Where direct load control by meter is not available, customer's load shall be controlled by a switching device approved or supplied by the Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,050.00
All additional kW of Billing Demand ($/kW)	$9.25
Transmission Demand Charge	
All kW of Billing Demand ($/kW)	$6.07
Energy Charge	
All kWh (¢/kWh)	5.165¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will be subject to a discount of 0.800¢ per kWh of Energy. Where service is delivered and metered

LARGE LIGHT AND POWER SERVICE

at (or compensated to) the available distribution bulk delivery voltage of 23,000 to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

LARGE LIGHT AND POWER SERVICE

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the lower of:

a) 75% of the greatest adjusted demand during the preceding eleven months, or
b) The greatest adjusted demand during the preceding eleven months minus 100 kW.

However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

RATE CODES

73

APPLICATION

To the electric service requirements of a customer requiring service for no less than 2,000 kW and no more than 50,000 kW of connected load, where such electric service requirements are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at the voltage level specified in customer's contract.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Light and Power Service Rate Schedules 75 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Light and Power Service Rate Schedules 75 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

2. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");

(b) The voltage level(s) at which service will be supplied;

(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;

(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;

(e) A confidentiality agreement; and

(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

LARGE POWER SERVICE

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company ("Confidential Information"), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term "Holidays" shall mean New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year's Eve Day.

For purposes of ESAs, the term "Office" shall mean the Minnesota Office of Energy Security or its successor organization.

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

LARGE POWER SERVICE

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge	
A single application for the first 10,000 kW or less of Firm Demand	$244,764
All additional kW of Firm Demand ($/kW)	$24.00
Transmission Demand Charge	
All kW of Firm Demand ($/kW)	$8.49
Energy Charge	
All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.187¢

Excess Energy Charge
All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under "ENERGY."

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

2. Fuel and Purchased Energy Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. Capacity Revenue and Expense Adjustment. A capacity revenue and expense adjustment will be determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

4. Conservation Adjustment. Adjustment will be determined in accordance with the Rider for Conservation Program Adjustment.

5. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

LARGE POWER SERVICE

6. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

7. CARE Low-Income Affordability Program Surcharge. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

8. Solar Energy Adjustment. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

9. Minnesota Policy Adjustment. The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

10. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

11. Franchise Fee. An adjustment for customers located within the corporate limits of the applicable city as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

LARGE POWER SERVICE

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be based on amount specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this a mount shall be deemed to be the Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases. For all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or

participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

LARGE POWER SERVICE

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Energy Portion

For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$293,717
All additional kW of Non-Contract Billing Demand ($/kW)	$28.80

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$10.19

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.187¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY."

Plus any applicable Adjustments.

NON-CONTRACT LARGE POWER SERVICE

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge. Such Fuel Charge shall be applicable to Customer's Non-Contract Firm Energy only.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

6. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Minnesota Policy Adjustment: The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

NON-CONTRACT LARGE POWER SERVICE

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are

usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

Capacity Portion

For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

Energy Portion

For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 74 for which a ten (10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes no responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

RATE CODES

79

APPLICATION

To the electric service requirements of a customer requiring 10,000 kW or more, where the electric service requirements of 10,000 kW or more are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Three phase, 60 hertz at high voltage of 13,000 through 69,000 volts or at transmission voltage of 115,000 volts.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Power Service Rate Schedules 74 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Power Service Rate Schedules 74 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

2. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installation)					
7,000 Lumens (175 watts)	MV175W	$12.92			
20,000 Lumens (400 watts)	MV400W	$20.57			
55,000 Lumens (1,000 watts)	MV1000W	$38.33			
Sodium Vapor Fixtures					
8,500 Lumens (100 watts)	SV100W	$11.34		$6.54	
14,000 Lumens (150 watts)	SV150W	$13.07			
23,000 Lumens (250 watts)	SV250W2	$18.54		$11.19	
45,000 Lumens (400 watts)	SV400W	$24.83		$11.87	
Metal Halide Fixtures					
17,000 Lumens (250 watts)	MH250W	$18.34			
28,800 Lumens (400 watts)	MH400W	$22.34		$13.24	
88,000 Lumens (1,000 watts)	MH1000W	$37.22		$24.18	
Light Emitting Diodes (LED)					
4,000 Lumens (48 watts or less)	LED48W	$11.45			
10,000 Lumens (71 watts or less)	LED71W	$11.99			
24,000 Lumens (184 watts or less)	LED184W	$20.76			
46,800 Lumens (320 watts or less)	LED320W	$31.52			
Pole Charge					
Each pole used for service under this schedule only	MPPOLE	$13.00		$13.00	

OUTDOOR AND AREA LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	11.010¢

Plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

   The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

2. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

   The monthly capacity revenue and expense adjustment per lamp shall be determined as the above capacity revenue and expense adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

OUTDOOR AND AREA LIGHTING SERVICE

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Fixture CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
	Daily Estimates	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours		4200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH250W	3	1,260	139	114	110	91	79	70	76	88	101	120	130	142
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MH1000W	12	4,410	485	398	385	317	277	245	264	309	353	421	457	499
LED48W	1	207	23	19	18	15	13	11	12	14	17	20	21	24
LED71W	1	299	33	27	26	21	19	17	18	21	24	28	31	34
LED184W	2	774	85	70	68	56	49	43	46	54	62	74	80	87
LED320W	4	1,344	148	121	117	97	84	75	81	94	108	128	139	152

Company shall furnish all electric energy required for service under this schedule.

OUTDOOR AND AREA LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, photo-electric control and wiring.

Option 2

Reserved for Future Use

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include, but not be limited to, the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.

OUTDOOR AND AREA LIGHTING SERVICE

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, will be at Customer's expense.

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$17.85		$13.34	
10,000 Lumens (250 watts)	MV250W			$16.95	
20,000 Lumens (400 watts)	MV400W	$24.28		$22.91	
55,000 Lumens (1,000 watts)	MV1000W2			$27.46	
Sodium Vapor Fixtures (Closed to New Installations)					
8,500 Lumens (100 watts)	SV100W	$15.77		$10.71	
14,000 Lumens (150 watts)	SV150W	$17.45		$15.08	
14,000 Lumens (150 watts)	SV150W-P			$9.11	
20,500 Lumens (200 watts)	SV200W	$21.58		$16.47	
23,000 Lumens (250 watts)	SV250W	$21.73		$17.79	
45,000 Lumens (400 watts)	SV400W	$26.69		$21.42	
Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$15.90			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$19.98			
23,000 Lumens (219 watts or less, but more than 118 watts)	LED219W	$26.74			

STREET AND HIGHWAY LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	11.010¢

Plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

   The monthly fuel and purchased energy adjustment per fixture shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

2. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

   The monthly capacity revenue and expense adjustment per fixture shall be determined as the above capacity revenue and expense adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8. Bills for service to parties within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for city's Franchise Fee.

STREET AND HIGHWAY LIGHTING SERVICE

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Fixture CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
	Daily Estimates	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours		4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W2	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV150W-P	1	468	51	42	41	34	29	26	28	33	37	45	48	54
SV200W	3	1,140	125	103	100	82	72	63	68	80	91	109	118	129
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

Company shall furnish all electric energy required for service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, fixture, ballast, photo-electric control, driver, and wiring.

Option 2

Reserved for Future Use

Option 3

The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, fixture, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out fixtures and photo-electric controls and will clean or replace glassware at the time of fixture replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to

STREET AND HIGHWAY LIGHTING SERVICE

deliver power to Customer's system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, fixture, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of fixtures of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the

STREET AND HIGHWAY LIGHTING SERVICE

Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For fixtures which satisfy the conditions as set forth in Options 1 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

7. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1, Company will repair equipment (not covered above) damaged by vandalism and will bill Customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79.

FUEL AND PURCHASED ENERGY CHARGE

The Forecasted System Average Fuel and Purchased Energy (FPE) Charge for each month shall be the forecasted FPE Charge for the current month divided by the forecasted Kilowatt-Hour Sales. The applicable Forecasted FPE Charge shall be added to customers' monthly bill according to each customer's rate class and Fuel and Purchased Energy Adjustment (FPEA) Factor.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending December 31 of each year as reported in the Annual Automatic Adjustment True-up report to be filed by March 1 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs to the forecasted costs and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under- recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each rate class shall be calculated as follows. The over- or under- recovery amount as shown in the current year Annual Automatic Adjustment True-up report will be divided by the forecasted Kilowatt-Hours subject to the fuel adjustment clause for the proposed twelve month recovery period the true-up rate will be in effect and then multiplied by the applicable FPEA Factor. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each rate class that will be applied to Customers' bills in the same manner as the forecasted monthly FPE Charge.

FORECASTED SYSTEM AVERAGE FUEL AND PURCHASED ENERGY CHARGE

The monthly Forecasted Average Fuel and Purchased Energy Charge shall be the **sum** of the following:

(a) The fossil and nuclear fuel forecasted to be consumed in Company's generating stations,

(b) The forecasted net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such

energy is to be purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,

(c) The forecasted identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,

(d) The forecasted cost of steam from other sources to be used in the generation of electricity at the Company's generating stations,

(e) The forecasted cost of the Released Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

(f) The forecasted cost of the Buyback Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,

(g) Forecasted fuel and purchased energy expenses to be incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691 excluding the cost of fuel and purchased energy related to meeting the Solar Energy Standard,

(h) All forecasted RTO (Regional Transmission Organization) energy market costs net of revenues, excluding administrative costs,

(i) The forecasted cost of the purchase of SO_2 and NOx allowances,

(j) The forecasted Time of Generation Adjustment as calculated in the Rider for Solar Energy Adjustment

(k) Reagent and chemical costs for environmental compliance

and **less**

(l) Forecasted revenues from the sale of SO_2 and NOx allowances,

(m) The forecasted cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis,

(n) Forecasted net revenues from the sale of environmental attributes from any Commission approved contract, and

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

(o) Forecasted net revenues (margins) from asset-based wholesale energy sales and capacity sales greater than three years.

The Forecasted Kilowatt-Hour Sales shall be Company's total forecasted kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (l) above and solar energy production and purchases referred to in (g) above.

FUEL AND PURCHASED ENERGY ADJUSTMENT (FPEA) FACTORS

A separate FPEA Factor shall be applied to calculate the Forecasted FPE Charge for each Rate Class. A Class Cost Factor shall be calculated for each Rate Class. For Residential Time-Of-Day (TOD) and Large Light & Power Time-Of-Use (TOU) customers a TOD or TOU Factor shall also be calculated for each TOD or TOU period. The FPEA Factor is the Class Cost Factor multiplied by the corresponding TOD or TOU Factor.

Rate Class	Class Cost Factor	TOD / TOU Factor	FPEA Factor
Residential	1.05841	1.00000	1.05841
Residential On-Peak	1.05841	1.17042	1.23878
Residential Off-Peak	1.05841	1.03330	1.09366
Residential Super Off-Peak	1.05841	0.75930	0.80365
General Service	1.02995	1.00000	1.02995
Large Light & Power	0.99451	1.00000	0.99451
Large Light & Power On-Peak	0.99451	1.17042	1.16399
Large Light & Power Off-Peak	0.99451	1.03330	1.02763
Large Light & Power Super Off-Peak	0.99451	0.75930	0.75513
Large Power	0.98328	1.00000	0.98328
Lighting	0.89264	1.00000	0.89264

2025 FORECASTED FPE RATE and 2023 TRUE-UP FPE RATE

The monthly forecasted 2025 FPE Rate was approved by the Minnesota Public Utilities Commission ("Commission") Order issued on November 12, 2024, in Docket No. E015/AA-24-64.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

The 2023 FPE True-up Rate was approved in the Commission Order issued on July 1, 2024, in Docket No. E015/AA-22-216.

Applicable Month	FPE 2025 Forecasted Rate (¢/kWh)	FPE 2023 True-up Rate (¢/kWh)
January 2025	3.262	(0.133)
February 2025	3.105	(0.148)
March 2025	2.893	(0.140)
April 2025	2.883	(0.153)
May 2025	2.874	(0.149)
June 2025	2.784	(0.153)
July 2025	3.087	(0.144)
August 2025	3.267	(0.145)
September 2025	3.015	
October 2025	2.881	
November 2025	2.844	
December 2025	3.267	

A breakdown by month and Rate Class can be found on Minnesota Power's website at https://www.mnpower.com/CustomerService/YourBill

TEMPORARY SERVICE RIDER TO GENERAL SERVICE SCHEDULES

Any customer whose use of service may be temporary (less than one year duration) shall receive service under the Conditions of this Rider in conjunction with a General Service Schedule modified as follows:

CONDITIONS

1. Customer will pay in advance the estimated cost of installation and removal, less salvage, of facilities required to render service. Where the actual cost of providing such facilities is different from the advance payment, as determined upon completion of temporary service, Company will refund any excess payment made by Customer or render a bill for any additional costs.

2. Customer may at any time terminate service under this Rider and contract to receive future service under any applicable Schedule.

3. If Customer requests that service be discontinued and subsequently requests restoration of service at the same premises within 12 months of discontinuance, the charge for restoring service will be the sum of the minimum bills during the elapsed period but not less than all costs of discontinuing and restoring service. The minimum bills during the elapsed period shall also include any billings which would have been applicable as a result of the minimum under the below Modification.

MODIFICATION

The second paragraph under DETERMINATION OF THE BILLING DEMAND in the applicable General Service rate schedule shall be changed to read as follows:

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the greatest adjusted demand during the preceding eleven months, nor less than the minimum demand specified in customer's contract.

SPORTS FIELD LIGHTING RIDER TO GENERAL SERVICE SCHEDULES

Any customer may elect to receive service for sports field lighting under the Conditions of this Rider in conjunction with a General Service Schedule modified as follows:

CONDITIONS

1. Service is available hereunder only to the extent that Company has unused capacity in facilities at the location. Customer shall pay any cost of extending or increasing the capacity of facilities.

2. Customer will own, install and maintain any transformers or other facilities required to utilize the available line voltage.

MODIFICATIONS

1. Service will be at the available line voltage (and phase).

2. The HIGH VOLTAGE SERVICE provision will not be applicable.

3. Demand will not be measured.

RIDER FOR MULTIPLE METER SERVICE

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through more than one meter. There may be conditions under which it will be desirable and/or necessary to provide service to customers at more than one point of delivery (Multiple Meter Service). Therefore, at Company's discretion, a customer not receiving multiple meter service or receiving multiple meter service but desiring an additional point of delivery may receive such service upon completion and proper approval of "Request for Multiple Meter Service".

CONDITIONS

1. When service is being taken through more than one meter, the metered quantities of demand (kW) and energy (kWh) at each metered point of service shall be billed under a separate application of a standard rate schedule.

2. The conditions under which a "Request for Multiple Meter Service" may be approved include but are not limited to:

    a. Customer's premises are divided by a public road or alley preventing the customer from performing its own distribution of service.

    b. Customer's buildings or operations are geographically separated to the extent that it is not electrically feasible for the customer to perform its own distribution of service.

    c. The location and/or adequacy of existing Company facilities make it economically more advantageous for Company to provide an additional point of delivery.

    d. Customers having two or more separate businesses on one premises for which the electric service costs must be accounted for separately.

RIDER FOR EXPEDITED BILLING PROCEDURES

APPLICATION

Applicable to taconite producing customers taking Large Power Service under Schedule 74 under Non-Contract Large Power Service Schedule 78, and under any other Large Power rate schedules in effect from time to time.

Service received under Large Light and Power Schedule 75 by a taconite producing Large Power customer may also be billed in accordance with this Rider, at the option of Minnesota Power.

Non-taconite customers taking service under a Large Power Service rate schedule may, at their option, be billed in accordance with the terms of this Rider.

The monthly billing requirement of Minnesota Rule 7820.3300 is modified to permit expedited weekly billing of a customer's electric service in accordance with the terms of this Rider.

TERMS

1. After instituting weekly billing, the bill payment is due in "same day funds" seven (7) days following issuance of the bill, the "Due Date" for payment. "Same day funds" means funds that are available for the Company's use on the same day as the Due Date. Bills not paid in "same day funds" on or before such Due Date as printed on the bill are "past due", or "delinquent." The weekly billing is based on estimated weekly electric service usage, including the minimum demand charge, not on an actual meter reading. Weekly billing payments received and charges for actual electric service usage will be reconciled each month ("actual billing true-up"). The monthly actual billing true-up shall be reflected on the first weekly billing rendered after such true-up amount has been determined. See Exhibit 1 to this Rider.

2. Customers subject to this Rider will receive credit for expedited billing payments reflecting the time value of funds made available to Minnesota Power earlier than such funds otherwise would have been available under the Company's standard monthly billing cycle. When the customer makes its first payment under the expedited cycle, the time value of money associated with that payment will be determined from the due date of that payment to the customer's due date under the standard monthly billing cycle, using prime plus two and one-half percent (2.5%) as the interest rate.

3. This time value of money credit ("TVMC") will be determined for each of the succeeding expedited payments. If the customer has not made timely payment of the estimated bills in full in "same day funds" as they become due on the expedited due dates, no time value of money associated with such late payment will be included in the TVMC. The total TVMC determined in a month shall be given by Minnesota Power

RIDER FOR EXPEDITED BILLING PROCEDURES

to the customer as a credit on the weekly bill that falls on the same week as the due date under the standard monthly billing cycle. If the credit exceeds $100,000, the customer has the option to have Minnesota Power wire the credit to the customer's bank account. The mechanics of this credit are shown on Exhibit 1 of this Rider. The prime rate is defined as the average of the daily prime lending rates offered to preferred customers at the largest bank in the Ninth Federal Reserve District in effect during the month preceding the bill.

RIDER FOR EXPEDITED BILLING PROCEDURES

MINNESOTA POWER
Sample Weekly Billing Procedure
Assuming Procedure Commences January 1

Jan	Tue	1	
	Wed	2	
	Thu	3	
	Fri	4	Bill #1 Issued = 4/31 x Estimated Monthly Billing (EMB) for January
	Fri	11	Bill #2 Issued = 7/31 x EMB for January Bill #1 Due
	Fri	18	Bill #3 Issued = 7/31 x EMB for January Bill #2 Due
	Fri	25	Bill #4 Issued = 7/31 x EMB for January Bill #3 Due
Jan	Thu	31	Meter Read
Feb	Fri	1	Bill #5 Issued = 6/31 x EMB for January + 1/28 x EMB for February Bill #4 Due
	Mon	4	Charges for actual January usage determined January TVMC calculated to February 19th
	Fri	8	Bill #6 Issued = 7/28 x EMB for February Bill #5 Due January Actual Billing True-Up amount determined
	Fri	15	Bill #7 Issued = 7/28 x EMB for February + Actual Billing True-Up amount for January Bill #6 Due
	Tue	19	January TVMC is applied to bill or wire transferred
	Fri	22	Bill #8 Issued = 7/28 x EMB for February Bill #7 Due
Feb	Thu	28	Meter Read
Mar	Fri	1	Bill #9 Issued = 6/28 x EMB for February + 1/31 x EMB for March Bill #8 Due
	Mon	4	Charges for actual February usage determined February TVMC calculated to March 19th
	Fri	8	Bill #10 Issued = 7/31 x EMB for March Bill #9 Due February Actual Billing True-Up amount determined
	Fri	15	Bill #11 Issued = 7/31 x EMB for March + Actual Billing True-Up amount for February Bill #10 Due
	Tue	19	February TVMC is applied to bill or wire transferred

RIDER FOR EXPEDITED BILLING PROCEDURES

MINNESOTA POWER
Sample Monthly Adjustments

January Time Value of Money Credit (TVMC from page 1) assuming Bill #'s 1 thru 5 are paid in full and when due:

January TVMC =
Bill #1 x [(# days from Jan 11 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #2 x [(# days from Jan 18 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #3 x [(# days from Jan 25 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #4 x [(# days from Feb 1 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Jan portion of Bill #5 x [(# days from Feb 8 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%)

January Actual Billing True-Up Adjustment =
Sum of Payments for January service received on or before Feb 19 - Actual Charges for January usage

February Time Value of Money Credit (TVMC from page 1) assuming only Bill #'s 5 and 6 are paid in full and when due:

February TVMC =
Feb portion of Bill #5 x [(# days from Feb 8 to Mar 19)/365] x (Avg. Daily Prime Rate in January + 2.5%) +

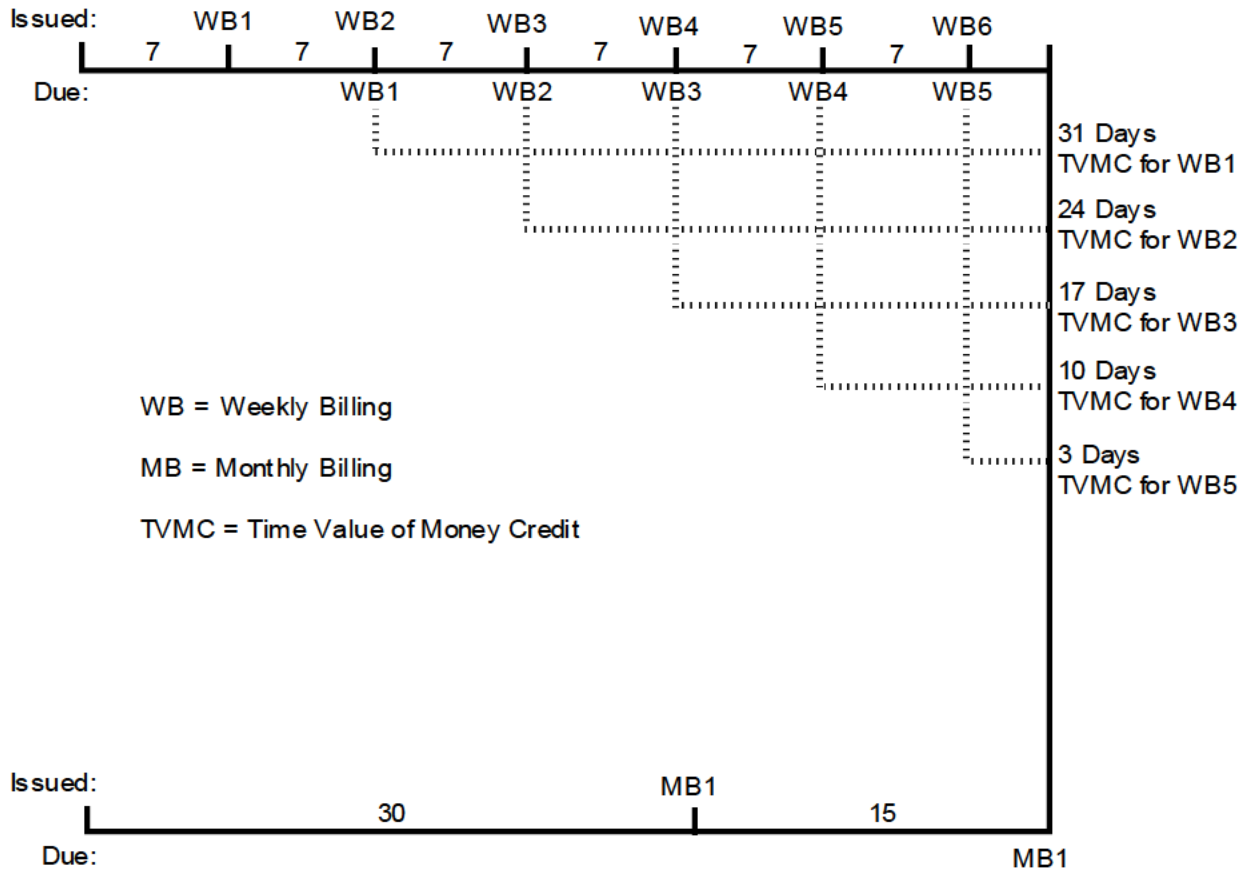
Bill #6 x [(# days from Feb 15 to Mar 19)/365] x (Avg. Daily Prime Rate in January + 2.5%)

February Actual Billing True-Up Adjustment =
Sum of Payments for February service received on or before Mar 19 - Actual Charges for February usage

Note: 1) Time Value of Money Credit will not be reflected for any Weekly Billing which has not been received in same day funds, in full and on or before the Due Date.
2) The TVMC is calculated to (and applied to bill or wire transferred on) the standard monthly billing cycle due date which is 15 days from the date customer is notified of the charges for actual monthly usage.

RIDER FOR EXPEDITED BILLING PROCEDURES

MINNESOTA POWER
METHOD FOR DETERMINING
TIME VALUE OF MONEY CREDIT



Note: This example assumes a 30 day month and the due date under the standard monthly billing cycle to be the 15th of the following month.

RIDER FOR SCHOOLS

APPLICATION

To Large Light and Power Service Schedule 75 for schools which are part of the elementary and secondary school system.

MODIFICATIONS

The RATE (Monthly) and other provisions of the applicable schedule shall apply except that:

1. The first block under Demand Charge shall be changed to read, "$10.50 per kW for the first 100 kW of Demand" or less as determined below.

2. Determination of the Billing Demand shall be replaced by the following:

   "Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month as adjusted for power factor, but not less than the minimum demand specified in customer's contract and in no case will the billing demand be less than 50 kW. For all Billing Demand between 51 kW and 100 kW the demand will be billed at the $10.50 per kW rate. All Billing Demand above 100 kW shall be billed at the third block demand rate of $9.25 per kW.

   Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%."

RIDER FOR REVENUE CREDIT FROM NON-CONTRACT LARGE POWER SERVICE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Non-Contract Large Power Service Schedule 78.

REVENUE CREDIT

There shall be deducted from each Customer's monthly bill, as computed under the applicable rate schedule, a Revenue Credit. Such Revenue Credit for each Customer, other than Large Power Service Schedule 74 Customers, shall be a monthly Revenue Credit Rate (¢/kWh) multiplied by the kWh billed in the current month. Such Revenue Credit for Large Power Service Schedule 74 Customers shall be a monthly Revenue Credit Rate ($/kW) multiplied by the Firm Power Billing Demand (kW) billed.

DETERMINATION OF REVENUE CREDIT AMOUNT

The Revenue Credit Amount in month shall be one-sixth (1/6) of the total of all Non-Contract Large Power Service Demand Charges billed in the second preceding month.

REVENUE CREDIT RATES

(a) Applicable to Non-Large Power Service (in ¢/kWh)

The Revenue Credit Amount in month multiplied by .3606; divided by Company's total kilowatt-hour Sales of Electricity, excluding Non-Contract Large Power Service, non-firm service, Resale Service and Large Power Service sales, in the second preceding month.

(b) Applicable to Large Power Service (in $/kW)

The Revenue Credit Amount in month multiplied by .5207; divided by the sum of all Firm Power Billing Demand (kW) billed to Customers under Company's Large Power Service Schedule 74 in the current month.

RIDER FOR CITY OF DULUTH FRANCHISE FEE

APPLICATION

Applicable to bills for electric service within the corporate limits of the City of Duluth, except bills for service to the City of Duluth.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Duluth Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Duluth, which is currently 3% of the total bill excluding sales taxes and is billed per electric service agreement. The fee is listed on the bill as "Duluth Franchise Fee (3%)" and is effective as January 1, 2017.

The total amount assessed to any Minnesota Power customer shall not exceed $420,000 per year.

100% of the City of Duluth Franchise Fee assessment collected will be passed along to the City of Duluth.

RIDER FOR PARALLEL GENERATION

APPLICATION

Applicable to cogenerator or small power producers less than 1,000 kW AC capacity. To any customer taking single or three phase service under one of the Company's standard electric rate schedules and who has entered into a contract with the Company for the sale of electricity as a cogenerator or small power producer (Seller) as defined under State or Federal Law.

RATE (Monthly)

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard rate schedule:

I. Sellers with Distributed Energy Resources less than 40 kW AC capacity shall have the option of selling to Company under either the Average Retail Energy Rate, the Simultaneous Purchase and Sale Rate or the Time-of-Day Purchase Rate. The Rate selected shall be as specified in the Cogeneration and/or Small Power Production Facilities Agreement between Seller and Minnesota Power.

A. Average Retail Energy Rate
The Seller shall be billed according to the Company's applicable standard rate schedule for the energy (kWh) supplied by the Company that exceeds the amount of energy supplied by the Seller to the Company's distribution system during each billing period. The Seller will be subject to the following Meter Aggregation Charge. When energy supplied by the Seller exceeds the amount of energy supplied by the Company, the Seller shall be subject to the following Average Retail Energy Rate Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Average Retail Energy Rate Credit
13.16¢ per kWh of Net Energy - Residential Customers
13.98¢ per kWh of Net Energy - General Service Customers
10.71¢ per kWh of Net Energy - Large Light & Power Customers

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by

RIDER FOR PARALLEL GENERATION

the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
3.05¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
5.35¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

II. Distributed Energy Resources at 40 kW AC capacity or greater and less than 500 kW AC capacity shall have the option of selling to Company under either the Kilowatt-Hour Energy Credit, the Simultaneous Purchase and Sale Rate, or the Time-of-Day Purchase Rate. Customers who do not elect to be compensated for net input in the form of a kilowatt-hour credit under the Kilowatt-Hour Energy Credit rate will be compensated for the net input at the Company's Simultaneous Purchase and Sale Rate or Time-of-Day Purchase Rate.

RIDER FOR PARALLEL GENERATION

A. Kilowatt-Hour Energy Credit Rate

The Seller shall be compensated for net input in the form of a kilowatt-hour credit shown on the customer's bill, which will be carried forward on subsequent energy bills. The Seller will be subject to the following Meter Aggregation Charge. Any remaining net input at the end of the calendar year shall be compensated at the applicable Credit as shown below:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company

B. Simultaneous Purchase and Sale Rate

The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate

The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and Energy and applicable Credit:

RIDER FOR PARALLEL GENERATION

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
3.05¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
5.35¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

III. Distributed Energy Resources at 500 kW AC capacity or greater and less than 1,000 kW AC capacity shall have the option of selling to Company under either the Kilowatt-Hour Energy Credit, the Simultaneous Purchase and Sale Rate, or the Time-of-Day Purchase Rate.

A. Kilowatt-Hour Energy Credit Rate
The Seller shall be compensated for net input in the form of a kilowatt-hour credit shown on the customer's bill, which will be carried forward on subsequent energy bills. The Seller will be subject to the following Meter Aggregation Charge. Any remaining net input at the end of the calendar year shall be compensated at the applicable Credit as shown below:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

RIDER FOR PARALLEL GENERATION

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and appliable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
3.05¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
5.35¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

DETERMINATION OF FIRM POWER

Energy delivered by the QF to the Company must have a 65 percent on-peak capacity factor in the month to be considered "firm power". The capacity factor is based upon the QF's maximum on-peak metered capacity delivered to the Company during the month. If the QF does not meet the firm power requirements, compensation will be for the energy portion only.

INDIVIDUAL SYSTEM CAPACITY LIMITS

1) Customers with a facility of 40-kilowatt AC capacity or more and participating in net metering and net billing may be required to limit the total generation capacity of an individual Distributed Energy Resource by either:

RIDER FOR PARALLEL GENERATION

a. for wind generation systems, limiting the total generation system capacity kilowatt alternating current to 120 percent of the customer's on-site maximum electric demand; or
b. for solar photovoltaic and other distributed generation, limiting the total generation system annual energy production kilowatt hours alternating current to 120 percent of the customer's on-site annual electric energy consumption.

2) Limits under paragraph (a) applicable to measuring on-site maximum electric demand must be based on standard 15-minute intervals, measured during the previous 12 calendar months, or on a reasonable estimate of the average monthly maximum demand or average annual consumption if the customer has either:
   a. less than 12 calendar months of actual electric usage; or
   b. no demand metering available.
3) The total generation capacity of an individual Distributed Energy Resource is determined by the total capacity of all of the customer's systems which are on the same set of aggregated meters. On-site maximum electric demand and on-site annual electric energy consumption are determined by total demand or electric energy consumption associated with the same set of aggregated meters.
4) For wind generation systems, the Company will estimate customer demand use for purposes of calculating the 120 percent rule by determining a demand-billed customer's highest billed on-site kW demand in all bills issued during the most recent calendar year. For non-demand customers, the Company shall impute the equivalent peak demand level by first determining the customer's most recent on-site annual (12-month) billed kWh sales. Those kWh sales shall be divided by the product of the annual load factor for the applicable customer class and the number of actual hours in that year (either 8,760 hours in a standard year or 8,784 hours in a leap year). The resulting quotient will serve as the customer's estimated on site maximum electric demand. The load factor is 19.3 percent for the residential customer class and 24.2 percent for the non-demand general service customer class as calculated in the Company's 2013 Load Research study.
5) For solar photovoltaic and other Distributed Energy Resources, where 12 months of usage data is not available, the Company will estimate customer energy use for purposes of calculating the 120 percent rule by averaging four months of usage. If four months of usage is not available, the Company will estimate usage based on home size for residential customers and other substantiating documentation for commercial and demand billed customers.

METER AGGREGATION

The Company will aggregate for billing purposes a Customer's designated distributed generation bidirectional meter with one or more aggregated retail meters if a Customer requests that it do so and the following conditions are satisfied:

RIDER FOR PARALLEL GENERATION

1) the meters must be located on contiguous property owned by the customer requesting the aggregation;
2) the account(s) associated with the meters must be in the name of the customer;
3) the retail services associate with the aggregated meters of a customer must be either all time-of-day or all non-time-of-day;
4) the total of all aggregated meters must be subject in the aggregate to the size limitation under the single rate chosen by the Customer applicable to all of the aggregated meters; and
5) the total of all aggregated meters is subject in the aggregate to the Individual System Capacity Limits.

As the term is used here, “contiguous property” means property owned or leased by the Customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or Company rights-of-way. The Company must comply with a request by a customer-generator to aggregate additional meters within 90 days. The specific meters must be identified at the time of the request. In the event that more than one meter is identified, the Customer must designate the rank order for the aggregated meters to which the net metered credits are to be applied. At least 60 days prior to the beginning of the next annual billing period, a Customer may amend the rank order of the aggregated meters.

The aggregation of meters applies only to charges that use kilowatt-hours as the billing determinant. All other charges applicable to each meter account shall be billed to the customer. The Company will first apply the kilowatt-hour credit to the charges for the designated meter and then to the charges for the aggregated meters in the rank order specified by the customer. If the Net Metered Facility supplies more electricity to the Company than the energy usage recorded by the customer-generator's designated and aggregated meters during a monthly billing period, the Company will apply, at the election of the Customer, any excess production based on a monthly credit or the Annual Net Metering (kWh) Banking Option. Where a monthly credit is selected, the Company shall apply monetary credits to the customer's next monthly bill for the excess kilowatt-hours.

DISTRIBUTED ENERGY RESOURCES OF 1,000 KILOWATT CAPACITY OR MORE

A Seller with 1,000 kW AC capacity or more must negotiate a contract with the Company to set the applicable rates for payments to the customer of avoided capacity and energy costs. Sellers fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10,000 kW AC capacity of interconnected capacity at a point of common coupling to Company’s distribution system may also apply for service under the Company’s Rider for Distributed Generation Service.

RIDER FOR PARALLEL GENERATION

DEFINITIONS

"Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. Data from the most recent 12-month period available before each filing required by parts 7835.0300 to 7835.1200 must be used in the computation.

“Capacity" means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current at the point of common coupling between a qualifying facility and a utility's electric system.

"Firm power" means energy delivered by the qualifying facility to the utility with at least a 65 percent on-peak capacity factor in the month. The capacity factor is based upon the qualifying facility's maximum on-peak metered capacity delivered to the utility during the month.

"Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical Distributed Energy Resources necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations, but instead generated from its own Distributed Energy Resources or purchased from other sources an equivalent amount of electric energy or capacity. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

"Net metered facility" means an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources.

“Off-Peak periods” shall include all hours not included in On-Peak periods.

“On-Peak periods” shall include all hours between 7 a.m. and 10 p.m. Central Prevailing Time, Monday through Friday excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

"Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial

operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions.

"Standby charge" means the rate or fee a utility charges for the recovery of costs for the provision of standby service or standby power.

"Standby service" means:
A. for public utilities, service or power that includes backup or maintenance services, as described in the public utility's commission-approved standby tariff, necessary to make electricity service available to the distributed generation facility; and
B. for a utility not subject to the commission's rate authority, the service associated with the applicable tariff in effect under Minnesota Statutes, section 216B.1611, subdivision 3, clause (2).

TERMS AND CONDITIONS

1. The interconnection between the QF and the Company must comply with the requirements in the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers.
2. The QF is responsible for complying with all applicable local, state, and federal codes, including building codes, the National Electrical Code (NEC), the National Electrical Safety Code (NESC), and noise and emissions standards. The Company requires proof that the QF is in compliance with the NEC before the interconnection is made. The QF must obtain installation approval from an electrical inspector recognized by the Minnesota State Board of Electricity.
3. The QF's generation system and installation must comply with the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) standards applicable to the installation.
4. Any existing Interconnection Agreement executed between the Company and a QF with capacity of less than 40 kilowatts remains in force until terminated by mutual agreement of the parties or as otherwise specified in the contract.
5. In accordance with Minnesota Rules 7835.5950, generators own all renewable energy credits unless other ownership is expressly provided for by a contract between the generator and the Company, state law specifies a different outcome, or specific commission orders or rules specify a different outcome.
6. Customers with a Distributed Energy Resource under 40 kW AC capacity shall execute a Uniform Statewide Contract with the Company in the form prescribed by Minn. Rules 7835.9910. Additionally, customers with a Distributed Energy Resource of 40 kW AC capacity or greater and less than 1,000 kW AC capacity may execute the Uniform Statewide Contract with the Company in the form prescribed by Minn. Rules 7835.9910

RIDER FOR PARALLEL GENERATION

to elect an eligible rate. Customers with a Distributed Energy Resource less than 40 kW AC capacity and less than 10,000 kW AC capacity shall execute the Minnesota Distributed Energy Resource Interconnection Agreement with the Company. Before the Customer signs the Uniform Statewide Contract or the Minnesota Distributed Energy Resource Interconnection Agreement, the Company shall provide the Customer a copy of, or link to current interconnection standards in accordance with Minnesota Rules 7835.4750.

7. In accordance with Minnesota Rules 7835.4500, in case of a dispute between the Company and a QF or an impasse in the negotiations between them, either party may request the Minnesota Public Utilities Commission (MPUC) to determine the issue. When the MPUC makes the determination, the burden of proof must be on the utility. Fees and costs for dispute resolution shall be in accordance with Minnesota Rules 7835.4550.
8. QFs with Distributed Energy Resources more than 100 kW AC capacity may be required to take service under the Company's Rider for Standby Service, as described in the tariff.
9. Customers with a Distributed Energy Resource sized between 40 kW AC capacity and 1,000 kW AC capacity taking service under the Rider for Parallel Generation will be required to install a separate production meter to record generation.

RIDER FOR STANDBY SERVICE

APPLICATION

Applicable to any Customer with on-site generation of 10 MW or less and taking service under one of Company's following standard rate schedules: General Service (Schedule 25), Large Light and Power Service (Schedule 75) and Large Power Service (Schedule 74) who has a distributed generation system which is able to generate on a continuous basis and who has entered into the "Minnesota Power's standard interconnection agreement" with the Company.

Service under this Rider shall be required for a Customer who has a distributed generation system that is run on a continuous basis and for non-emergency purposes which normally serves all or a portion of that Customer's electric load requirements, and who desires use of the Company's electric service for temporary backup. Exceptions to this Application include: (i) For any Customers with distributed generation systems rated at 100 kW or less, standby service will be available through their standard rate schedules; or (ii) any Customer, in lieu of service under this Rider, who provides physical assurance that standby service is not taken. A Customer requesting physical assurance shall agree to furnish and install an approved load limiting device which shall be set and sealed by the Company to prevent the Customer from utilizing standby service. The cost of the load limiting device shall be paid by the Customer.

The Customer shall execute a Standby Service Agreement with the Company for service under this Rider. The initial minimum term of service taken under this Rider shall be one (1) year. At the end of the initial term the contract will be automatically renewed on an annual basis, unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the initial term or any subsequent renewal thereof.

Energy provided to the Customer under this rider is limited to energy for Scheduled and Unscheduled Outages as defined below. The Customer shall not generate and allow energy flow onto the Company's system unless it is separately metered and permitted in accordance with the Company's Electric Service Regulations.

All provisions of the applicable standard rate schedule shall apply to service under this Rider except as noted below.

TYPE OF SERVICE

Service shall be taken at 60 hertz and at the voltage and phase relationship specified under the Company's applicable standard rate schedule for service to the Customer.

RIDER FOR STANDBY SERVICE

DEFINITIONS

Nominated Standard Service
Billed demand up to the level specified in the Standby Service Agreement under the Customer's standard rate schedule.

Reserved Standby Service
Maximum Scheduled Outage or Unscheduled Outage service allowed under this Rider for Standby Service as stated in the Standby Service Agreement. The contracted Reserved Standby Service shall not exceed the nameplate capacity of the Customer's distributed generation system.

Excess Standard Service
Demand utilized in excess of the aggregation of the Customer's Nominated Standby Service and Reserved Standby Service billed on the Customer's standard rate schedule.

Scheduled Standby Service Demand
Measured demand during Scheduled Outages greater than the Nominated Standard Service that is not Excess Standard Service.

Unscheduled On-Peak Standby Service Demand
Measured demand during Unscheduled Outages and on-peak periods greater than the Nominated Standard Service that is not Excess Standard Service. On-peak periods shall include all hours between 6 a.m. and 10 p.m. Central Prevailing Time Monday through Friday excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

Unscheduled Off-Peak Standby Service Demand
Measured demand during Unscheduled Outages and off-peak periods in excess of Unscheduled On-Peak Standby Service Demand and greater than the Nominated Standard Service that is not Excess Standard Service. Off-peak periods shall include all hours not included in on-peak periods.

Generator Outage Rate
The unplanned generator outage expressed as a percentage. For the first twelve (12) months the Customer takes service under this Rider, such rate shall be the Equivalent demand Forced Outage Rate (EFORd) class average published on the Midcontinent Independent System Operator (MISO) website most similar to the Customer's generation. The EFORd measures the probability that a generating unit will not be available. For subsequent 12-month periods, the Generator Outage Rate will be calculated based on generator availability for the Customer's generating facilities within the previous 12-month period. The Generator Outage Rate for the Customer's generating facilities shall be

calculated as the number of hours the generator was not available in the prior 12-month period excluding Scheduled Outages divided by the number of hours in a year.

Scheduled Outage
Planned outage periods that shall be prearranged by the Customer with the Company. Scheduled outages are available in April, May, October, November during any hours, and in all other months during off-peak hours between 10:00 p.m. and 06:00 a.m. Central Prevailing Time Monday through Friday, and all hours on weekends and holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. The Customer must provide at least a 45-day notice of its proposed timeline for a Scheduled Outage. The Customer may modify the outage schedule with 45 days' notice to the Company.

Scheduled Outages may not exceed 60 days in any continuous 12-month period unless otherwise agreed to by the Company in writing. Any extension of the outage period may be requested by the Customer in writing and shall be responded to by the Company in writing.

Customers that do not comply with the terms and conditions for qualifying Scheduled Outage periods will be subject to Unscheduled Outage charges as defined below.

Unscheduled Outage
Any outage that occurs outside of the allowed months listed above or which occurs without a 45-day notice to the Company. Any usage above the Nominated Standard Service that does not occur during the Scheduled Outage periods as defined above or that exceeds the allowed number of Scheduled Outage days will be treated as an Unscheduled Outage.

RATE (Monthly)

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule:

Standby Reservation Fee ($/kW)
For purposes of applying the Standby Reservation Fee, the contracted Reserved Standby Service shall be the quantity specified by the Customer in the Standby Service Agreement with the Company. The contracted Reserved Standby Service shall not exceed the nameplate capacity of the Customer's distributed generation system.

The Customer shall pay a Standby Reservation Fee equal to the rate specified below times the contracted Reserved Standby Service and multiplied by the Generator Outage Rate as stated in the Customer's Standby Service Agreement.

RIDER FOR STANDBY SERVICE

Standby Reservation Fee Rate

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	25.32	37.15
Primary	21.20	29.95	NA
Secondary	23.22	30.63	NA

During months in which Scheduled or Unscheduled Outages occur, the Standby Reservation Fee shall apply only if the Standby Demand Charge as defined below is less than the Standby Reservation Fee.

Standby Demand Charge ($/kW)

The Standby Demand Charge shall be sum of Scheduled and Unscheduled Standby Demand Charges as defined below. During months in which Scheduled or Unscheduled Outages occur, the Standby Demand Charge shall only apply if the Standby Reservation Fee as defined above is less than the Standby Demand Charge.

Scheduled Outage

For purposes of applying the Standby Demand Charge during Scheduled Outages, the measured demand shall be determined during the 15-minute period of the Customer's greatest Scheduled Standby Service Demand during the billing month. To determine the standby billing demand, the measured demand will be multiplied by the number of days the Scheduled Outage lasts during the billing month and divided by the number of days in the billing month.

During Scheduled Outages, the Customer shall pay a Standby Demand Charge equal to the rate established in the standard rate schedule times the standby billing demand.

Unscheduled Outage

For purposes of applying the Standby Demand Charge during Unscheduled Outages, the demand shall be determined during the 15-minute periods of the Customer's greatest Unscheduled On- and Off-Peak Standby Service Demands during the billing month.

During Unscheduled Outages, the Customer shall pay a Standby Demand Charge equal to the rate defined below times the corresponding Unscheduled On- and Off-Peak Standby Service Demand.

RIDER FOR STANDBY SERVICE

On-Peak Standby Demand Charge

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	26.31	38.61
Primary	22.03	31.12	NA
Secondary	24.13	31.83	NA

Off-Peak Standby Demand Charge

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	24.37	35.75
Primary	20.40	28.82	NA
Secondary	22.35	29.48	NA

Energy Charge

Scheduled Outage

The Customer shall pay for all energy usage during a Scheduled Outage according to their standard rate schedule, plus any applicable adjustments.

Unscheduled Outage

For all energy usage during an Unscheduled Outage, the Customer shall pay the Company's hourly incremental energy costs during the time of the sale, including third-party transmission costs incurred by the Company, plus an energy surcharge of $0.02 per kWh. Incremental energy costs are determined after assigning lower-cost energy to all firm retail and firm wholesale Customers including all inter-system pool sales which involve capacity on a firm or participation basis and to all interruptible sales to Large Power, Large Light and Power, and General Service Customers.

RIDER FOR STANDBY SERVICE

SERVICE CONDITIONS

1. All electricity delivered to the Customer by the Company shall be measured by one or more meters installed at a single point of common coupling or as determined by the Company. The Company's meter for standby service shall measure the flow of capacity and energy from the Company to the Customer only. Any flow of capacity and energy from the Customer to the Company shall be separately metered.

2. The Customer shall be required to pay the installation, operation, and maintenance costs incurred by the Company for the metering equipment installed on the Customer's generation equipment. Access shall be provided by the Customer to the Company for maintaining and operating such equipment.

3. The Company shall not be obligated to supply standby service to back up the Customer's distributed generation system at a level in excess of Reserved Standby Service. This restriction in no way limits the electric load requirements for which the Customer may require service from the Company under the standard rate schedule to which this Rider is attached.

4. Service shall be provided under this Rider if the Company has sufficient capacity available in existing production, transmission and distribution facilities to provide such service at the location where service is requested.

5. The Customer shall pay the Company the installed cost of any additional required facilities which are not supported by this Rider.

6. The Company may be reimbursed by the Customer for costs which are incurred, or which have been incurred, in providing facilities which were utilized principally or exclusively in providing service for any portion of the Customer's electric load requirements which are to be normally provided from the distributed generation system.

7. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

RIDER FOR STANDBY SERVICE

Minnesota Power
Standby Rate Options

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule:

Unscheduled Outage			
	Transmission	**Distribution Primary**	**Distribution Secondary**
Minimum Monthly Bill	Greater of Reservation Fee or Demand Charge + Energy Charge	Greater of Reservation Fee or Demand Charge + Energy Charge	Greater of Reservation Fee or Demand Charge + Energy Charge
General Service			
Reservation Fee	N/A	$21.20 ($/kW)	$23.22 ($/kW)
On-Peak Demand Charge	N/A	$22.03 ($/kW)	$24.13 ($/kW)
Off-Peak Demand Charge	N/A	$20.40 ($/kW)	$22.35 ($/kW)
Energy Charge	N/A	incremental	incremental
Large Light & Power			
Reservation Fee	$25.32 ($/kW)	$29.95 ($/kW)	$30.63 ($/kW)
On-Peak Demand Charge	$26.31 ($/kW)	$31.12 ($/kW)	$31.83 ($/kW)
Off-Peak Demand Charge	$24.37 ($/kW)	$28.82 ($/kW)	$29.48 ($/kW)
Energy Charge	incremental	incremental	incremental
Large Power			
Reservation Fee	$37.15 ($/kW)	N/A	N/A
On-Peak Demand Charge	$38.61 ($/kW)	N/A	N/A
Off-Peak Demand Charge	$35.75 ($/kW)	N/A	N/A
Energy Charge	incremental	N/A	N/A

Note: The reservation fee only applies in months when no standby service was taken or when the calculated demand charge is less than the reservation fee. The Reservation Fee is multiplied by the generator outage rate for billing purposes.

RIDER FOR STANDBY SERVICE

Minnesota Power
Standby Rate Options

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule, plus any applicable adjustments:

Scheduled Outage			
	Transmission	**Distribution Primary**	**Distribution Secondary**
Minimum Monthly Bill	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments
General Service without a Demand Meter			
Reservation Fee	N/A	$21.20 ($/kW)	$23.22 ($/kW)
Demand Charge[1]	N/A	N/A	N/A
Energy Charge	N/A	9.919 (¢/kWh)	9.919 (¢/kWh)
General Service with a Demand Meter			
Reservation Fee	N/A	$21.20 ($/kW)	$23.22 ($/kW)
Demand Charge[1]	N/A	$10.53 ($/kW)	$10.53 ($/kW)
Energy Charge	N/A	6.931(¢/kWh)	6.931(¢/kWh)
Large Light & Power			
Reservation Fee	$25.32 ($/kW)	$29.95 ($/kW)	$30.63 ($/kW)
Demand Charge[1]	$15.32 ($/kW)	$15.32 ($/kW)	$15.32 ($/kW)
Energy Charge	5.165 (¢/kWh)	5.165 (¢/kWh)	5.165 (¢/kWh)
Large Power			
Reservation Fee	$37.15 ($/kW)	N/A	N/A
Demand Charge[1]	$32.49 ($/kW)	N/A	N/A
Energy Charge	1.187 (¢/kWh)	N/A	N/A

Note: The reservation fee only applies in months when no standby service was taken or when the calculated demand charge is less than the reservation fee. The Reservation Fee is multiplied by the generator outage rate for billing purposes.

[1] The demand charge is calculated based on a daily proration.

RIDER FOR STANDBY SERVICE

STANDBY BILLING EXAMPLES

Scheduled Outage:

Customer Example:		
Peak Load	5,000	kW
Nominated Standard Service	3,000	kW
Reserved Standby Service	2,000	kW
Generator Outage Rate	10%	
Scheduled Standby Service Demand	2,000	kW
Outage Days	5	
Standby Energy Used	156,000	kWh
Standard Service Schedule	Large Light & Power	
Service Voltage	115,000 volts	

	Billing Units		**Rate**	**Billing**
Reservation Fee	200	kW	$ 25.32	$ 5,064.00
*Reserved Standby Service * Generator Outage Rate * Reservation Fee*				
Note: Not charged if Standby Demand charge is greater				
Demand Charge				
	2,000	kW	$ 15.32	$ -
	2,000	kW	$ (2.45)	$ -
*Scheduled Standby Service Demand * Standard Service Rate * (# of Outage Days/Days in Month)*				
Energy Charge	156,000	kWh	$ 0.05165	$ 8,057.40
	TOTAL STANDBY SERVICE BILLING			**$13,121.40**
Also subject to other applicable adjustments				

RIDER FOR STANDBY SERVICE

Unscheduled Outage:

Customer Example:		
Peak Load	5,000	kW
Nominated Standard Service	3,000	kW
Reserved Standby Service	2,000	kW
Generator Outage Rate	10%	
Unscheduled Off-Peak Standby Service Demand	500	kW
Note: Customer standby demand peaked at 2,000 kW in off-peak hour		
Unscheduled On-Peak Standby Service Demand	1,500	kW
Standby Energy Used	156,000	kWh
Standard Service Schedule	Large Light & Power	
Service Voltage	115,000 volts	

	Billing Units		Rate	Billing
Reservation Fee	200	kW	$25.32	$0.00
*Reserved Standby Service * Generator Outage Rate * Reservation Fee*				
Note: Not charged if Standby Demand charge is greater				
Demand Charge				
Unscheduled Off-Peak Standby Service Demand	500	kW	$24.37	$12.185.00
*Unscheduled Off-peak Standby Service Demand * Off-peak Standby Demand Charge*				
Unscheduled On-Peak Standby Service Demand	1,500	kW	$26.31	$39,465.00
*Unscheduled On-peak Standby Service Demand * On-peak Standby Demand Charge*				
Energy Charge	156,000	kWh	$0.0550	$8,580.00
Company's hourly incremental energy costs during the time of sale				
Rate of $0.055 per kWh is for example purposes				
	TOTAL STANDBY SERVICE BILLING			**$60,230.00**

Also subject to other applicable adjustments

RIDER FOR FOND DU LAC RESERVATION BUSINESS LICENSE FEE

APPLICATION

Applicable to billings for electric service provided within the Fond du Lac Reservation located in the southern portion of St. Louis County and the northern portion of Carlton County, Minnesota.

ADJUSTMENT

In accordance with the Corporate Code, Business License System and Employment Rights Law contained in the Fond du Lac Reservation Ordinance 5/84, businesses operating within the Reservation shall pay an assessment of 0.5 percent on revenues from sales within the Reservation. Therefore, there shall be added to each customer's monthly electric service bill a Fond du Lac Reservation Business License Fee assessment. The amount of the fee to be assessed shall be the applicable Assessment Rate multiplied by the Customer's bill for electric service. Compliance by Minnesota Power with the Business License System is governed by the terms of an agreement dated September 25, 1985, as amended by letter dated January 6, 1986, made with the Reservation Business Committee. Since the License Fee assessable by Minnesota Power applies retroactively to October 2, 1985, the initial Assessment Rate shall be 1.0 percent until such time as all retroactive amounts have been collected. Thereafter, the Assessment Rate shall be 0.5 percent.

RIDER FOR CONSERVATION PROGRAM ADJUSTMENT

APPLICATION

Applicable to bills for electric service under all Retail Rate Schedules except for Company's Competitive Rate Schedules 73 and 79. This Rider shall not be applicable to Economy or Standby service to retail customers.

Except as provided below in the CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS section, there shall be added to each non-CIP exempt customer's monthly bill a Conservation Program Adjustment (CPA) charge which shall be the applicable CPA factor multiplied by the customer's monthly kWh of energy usage. The applicable CPA factor per kWh shall be determined annually as described below.

DETERMINATION OF THE CONSERVATION PROGRAM ADJUSTMENT FACTOR

The Conservation Program Adjustment factor shall be the quotient of the Recoverable Tracker balance, divided by projected retail energy sales (exclusive of those energy sales from customers who have been granted an exemption from CIP costs (see CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS section). The CPA factor will remain in effect until subsequent MPUC approval of an updated factor. The Recoverable Tracker balance shall be determined by adjusting the prior year-end Conservation Improvement Program (CIP) Tracker balance by:

1) Subtracting the unamortized beginning CIP Tracker account balance;
2) Adding financial incentives awarded by the MPUC not reflected in the prior year-end balance;
3) Adding actual and anticipated CIP program expenditures at their approved and/or budgeted level for the applicable time period; and
4) Subtracting actual and anticipated CIP cost recovery through base rates, determined by multiplying the CCRC (shown below) by the Company’s budgeted retail sales in kWh to non-CIP exempt customers for the applicable time period; and
5) Subtracting actual and anticipated CIP cost recovery from the applicable CPA factor not accounted for in the prior year-end balance, as determined by multiplying the applicable CPA by the Company’s budgeted retail sales in kWh to non-CIP exempt customers for the remaining applicable time period. The remaining applicable time period for the applicable CPA is dependent upon subsequent MPUC approval which, for the purposes of this calculation, Minnesota Power assumes to align with the end of the current fiscal year (June 30, 2024).

RIDER FOR CONSERVATION PROGRAM ADJUSTMENT

All costs appropriately charged to the CIP Tracker account shall be eligible for recovery through this adjustment and all revenues received from the application of the CPA factor shall be credited to the CIP Tracker account.

In order to normalize the effect of significant changes in the CPA factor, the Company may request approval of an upper limit or cap on the calculated CPA factor.

The CPA factor effective December 1, 2024 for all non-CIP exempt customers shall be 0.1444¢ per kWh.

DETERMINATION OF CONSERVATION COST RECOVERY CHARGE (CCRC)

The CCRC is the amount included in base rates dedicated to the recovery of CIP costs as approved by the Minnesota Public Utilities Commission in the Company's last general rate case. The CCRC is approved and applied on a per kWh basis by dividing the test-year CIP expenses by the test-year sales volumes (net of CIP-exempt volumes). All revenues received from the CCRC shall be credited to the CIP Tracker Account.

The CCRC effective March 1, 2025 for all non-CIP exempt customers is 0.458916¢ per kWh.

CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS

For customers granted an exemption from CIP costs by the Commissioner of the Minnesota Department of Commerce, pursuant to Minn. Stat. § 216B.241, the CPA factor shall not be applicable. No CCRC is included in base rates for Large Power customers. For Large Power customers who have not been granted an exemption, the CCRC of 0.458916¢ per kWh shall apply to the total billing energy. In addition, non-Large Power customers who have been granted an exemption shall receive a billing credit of 0.458916¢ per kWh to offset the CCRC that is included in base rates under the applicable rate schedule. For those customer accounts granted exemption by a decision of the Commissioner after the beginning of a calendar year, any CIP collections billed after January 1 of the year following the Commissioner's decision shall be credited back to customers.

RIDER FOR NON-METERED SERVICE

APPLICATION

To General Service Schedules 25

DISCUSSION

Minnesota Power provides service for several types of operations that would normally be a part of the General Service class of customers. However, due to the unique nature of the customer's operations it is not always practical to meter the service points. Therefore, at Company's discretion, a customer may receive service under the General Service - Non-Demand Schedule without the metering requirements of that schedule and be billed for energy usage based on the table below. Additional end-use types and associated energy usages per unit may be added from time to time to address new situations. For purposes of applying the appropriate service charge, one service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required for service under the applicable General Service Schedule. In the case of Holiday decorative lighting, the customer shall be billed with a single service charge and energy usage per the table below one time per the holiday season, estimated at 45 operating days for 12 lighting hours per day.

Item Type	Description	Units	Estimated Monthly Energy Usage/Unit
SEC-CAM	Security Cameras	kWh	43 kWh
CBL2WY90	90v 2-Way Comm Cable PS	Volts	617 kWh
AMP-CBL	Amplifier Cable	Amplifiers	377 kWh
XFLSHR60	Crossing Flashers-60kWh	kWh	60 kWh
HS160W	Strip Heaters-160Watts	kWh	65 kWh
HSGREHRT	Strip Heaters-GRE Hartford 99	kWh	58 kWh
SIGN-LTG	Sign Lighting	Signs	25 kWh
SIRENS	Civil Defense Sirens	Sirens	1 kWh
RR-XING	Railroad Crossings	Crossings	39 kWh
NOWIRE15	Wireless Metering-15kWh	kWh	15 kWh

RIDER FOR NON-METERED SERVICE

HL-LED	Holiday Lighting – LED	Bulbs	22.5 Watt-hours
HL-INCT	Holiday Lighting – Incandescent	Bulbs	315 Watt-hours

RIDER FOR GENERAL SERVICE/LARGE LIGHT AND POWER INTERRUPTIBLE SERVICE

APPLICATION

Applicable to any Customer taking service under General Service (Schedule 25) or Large Light and Power Service (Schedule 75) and which has at least 200 kW of Interruptible Load that qualifies for interruptible service. All provisions of the applicable standard Service Schedule shall apply to interruptible service under this Rider except as noted below.

RATE MODIFICATION

The Rates (Monthly) of the applicable General Service or Large Light and Power Service Schedules shall apply. Additionally, the Customer shall receive a billing credit which will be 11 percent of the Customer's interruptible billing before any other applicable Adjustments.

INTERRUPTIBLE ENERGY CONDITIONS

Interruptible energy must meet applicable requirements to accredit capacity for satisfying resource adequacy requirements, including, but not limited to, maximum number of annual emergency curtailments, maximum duration of emergency curtailments, and seasons in which emergency curtailments can occur. During a Midcontinent Independent System Operator (MISO) emergency event the Company will call on this capacity as allowed under the requirements to accredit capacity for satisfying resource adequacy requirements or to mitigate local system emergency events. Before an Emergency Curtailment, the Company will provide the lesser of (1) at least two hours advance notice or (2) the notice that is required in connection with requirements to accredit capacity for satisfying resource adequacy requirements.

PRICE RECALL CONDITIONS

The Company shall have the right to re-price the Customer's Interruptible Load energy at 110% of the Company's incremental supply cost for up to 100 hours per year. During a price recall period the Customer will be given the option to continue service without interruption under the terms of this Rider. The Company will provide day-ahead email notice by 4:00 p.m. Central Prevailing time on the day prior to the price recall period(s), which will include the estimated prices during the price recall period(s). The Customer will have the option to curtail during the re-pricing periods or continue normal operation and pay 110% of the incremental supply cost for all Interruptible Load during the re-pricing period. Re-pricing periods will occur between the hours of 6:00 a.m. to 10:00 p.m. with the exception of time periods when MISO has declared an alert or emergency for the Minnesota Power service area.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED PHYSICAL INTERRUPTION

A Customer is deemed to have failed to comply with the emergency capacity requirements when Minnesota Power calls on the emergency capacity and the Customer's actual firm load, as measured by the meters installed by the Company (netted across aggregated Customer facilities, if applicable), has not decreased to the targeted demand reduction

threshold specified in the Customer's annual contract. In the event that the Customer fails to follow an Interruption request by Minnesota Power and such failure results in (a) any financial penalties being imposed upon the Company, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases, the Customer shall reimburse the Company for that portion of the penalty and/or financial damages caused by their failure, within 15 days of notification by Minnesota Power. In the event that the Customer follows Interruption conditions as specified herein, the Customer shall not be liable for any (a) penalties imposed on the Company, or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases. Penalties and charges may include, but are not limited to, penalties associated with disqualification of the emergency capacity as accredited capacity.

SERVICE CONDITIONS

1. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than the Customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) at such other times when in the Company's opinion the reliability of the system is endangered,
   (d) when MISO declares an emergency event, or
   (e) when the Company performs necessary testing for certification of interruptibility of Customer's loads.

2. The Company shall not be liable for any loss or damage including consequential damages, caused by or resulting from any interruption of service.

3. The Customer must be able to physically interrupt its Interruptible Load when notified by the Company.

4. The Company may accredit and register the demand response MW as a capacity resource with MISO (or successor entity), in accordance with the Module E Tariff and Business Practices Manual for Resource Adequacy. The Customer agrees to participate fully in the registration procedure.

5. In the event of a material change in MISO's (or any successor organization) capacity accreditation authority, the parties shall in good faith determine the most appropriate substitute and rate or cost determination authority within six months of the date such a change was made. Except as mutually agreed by the party's, no changes in MISO responsibilities shall materially and adversely affect either parties rights or obligations

under the Electric Service Agreement. Any changes would be subject to regulatory approval.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. The Customer shall pay the Company the installed cost of any additional facilities required which are not supported by this rate.

7. The term of service under this Rider shall be no less than one year and must be consistent with the MISO or successor Planning Year or other planning criteria as determined by the Company. However, the Company, at its sole discretion, reserves the right to provide the Customer with a three-month notice to discontinue providing service under this Rider.

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

APPLICATION

Applicable to any Customer taking service under Large Power Service Schedule 74, whose Electric Service Agreement has a minimum term of at least four (4) years beyond the initiation of Incremental Production Service hereunder and which provides for the sale by the Company and the purchase by the Customer of Incremental Production Service, subject to the conditions set forth in the Customer's Electric Service Agreement and this Rider. Application of this Rider and establishment of an Incremental Production Service Threshold ("IPST") for those Customers with self-generation and whose Electric Service Agreement allows for purchase of Economy Energy shall be at the sole discretion of the Company.

DEFINITIONS

Real-time Buy-through Period: Period called by the Company where Company will re-price Incremental Production Service ("IPS") energy and where Customer will respond through curtailing IPS load or buying-through at the real-time locational marginal price ("LMP").

Curtailment Period: Period called by the Company where Customer is required to curtail load.

Renewable Surplus Period: Period called by the Company during times of high renewable generation, low system load or low LMPs where Customer may exceed 110% of the IPST.

RATE MODIFICATIONS

Demand Charge
During any Billing Month in which the Customer has Measured Demand in excess of the IPST but not greater than 110% of the IPST or has Measured Demand in excess of the IPST during a Renewable Surplus Period, the Customer's Measured Demand above the IPST shall not be subject to any demand charges or ratchet provisions associated with Contract Demand and Incremental Service Requirements under the Large Power Service Schedule and the Customer's Electric Service Agreement unless otherwise provided in this Rider or the Customer's Electric Service Agreement. If Customer has Measured Demand in excess of the IPST during a Curtailment Period, the Customer's Billed Demand will be increased by the amount the Measured Demand exceeded the IPST, and the Customer will be subject to any penalties imposed upon Company by the Midcontinent Independent System Operator ("MISO") or a successor entity relating specifically to Customer's failure to curtail IPS service.

Energy Charge
During any Billing Month in which the Customer has Measured Demand in excess of the IPST, the energy associated with the Customer's Measured Demand above the IPST shall

be subject to an energy charge equal to the Incremental Production Rate, the Real-time Buy-through Period Rate or the Curtailment Period Rate.

Incremental Production Rate
The Incremental Production Rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly day-ahead LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company.

Real-time Buy-through Period Rate
The Real-time Buy-through Period Rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company .

Curtailment Period Rate
The Curtailment Period rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company.

Renewable Surplus Period Rate
The Renewable Surplus Period rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company.

Excess Reactive Demand
Whenever a Customer's metered demand exceeds the IPST, the Company shall not bill the Customer for any excess reactive demand adjustments below the level specified in the Customer's Electric Service Agreement. However, the Company may, at its sole discretion, bill the Customer for any excess reactive demand adjustments above the specified level at the Excess Power Demand Charge, with excess reactive demand calculated as indicated in the Large Power Service Schedule.

SERVICE CONDITIONS

1. All curtailments, buy-throughs, or Company declarations of Curtailment Periods or Renewable Surplus Periods can be superseded by Company requests of Customer to

curtail load as soon as reasonably possible for purposes of grid stability, in accordance with Company's Service Regulations.

2. The Customer shall be permitted to purchase Incremental Production Service from the Company, for service above the IPST established in the Electric Service Agreement, whenever the Customer's Measured Demand during any Billing Month exceeds the IPST, with the exception of during Curtailment Periods.

The Customer's Measured Demand shall not exceed 110% of the IPST without the Company declaration of a Renewable Surplus Period or Company's prior written consent, which consent shall not be unreasonably withheld. In the event that the Customer exceeds this level without Company consent or outside of Renewable Surplus Periods, the Company may increase the Customer's contractual requirements, including Contract Demand, IPST, or other related terms, by that amount for the duration of the Customer's Electric Service Agreement.

Additional Service Conditions for Real-time Buy-through Periods

3. Upon notification from the Company of a Real-time Buy-through Period, the Customer has the option of reducing its metered demand to the IPST by the time given by the Company or have the Incremental Production Service energy repriced at the Real-time Buy-through Rate. The Customer shall be given 30 minutes or greater notice of a Curtailment Period.

4. Real-time Buy-through Periods will not be called for greater than 170 hours per calendar year, excluding MISO capacity event curtailments.

5. The duration and frequency of Real-time Buy-through Periods shall be at the sole discretion of the Company. Real-time Buy-through Periods shall normally occur during times of high or volatile real-time LMPs or low generation.

Additional Service Conditions for Curtailment Periods

6. Upon notification from the Company of a Curtailment Period, the Customer shall reduce its metered demand to the IPST by the time given by the Company, and for a duration as required by the Company. The curtailment shall be for the entire amount of Incremental Production Service unless otherwise notified by the Company. The Company shall give Customer 30 minutes or greater notice of a Curtailment Period. Thirty (30) minute notification under this Rider shall be via automatic control unless otherwise provided in the Customer's Electric Service Agreement.

7. Curtailment Periods will not be called for more than 170 hours per calendar year, excluding MISO capacity event curtailments.

8. Curtailment Periods will not be called for more than eight hours per day and no more than four hours per Curtailment Period.

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

9. The duration and frequency of Curtailment Periods shall be at the sole discretion of the Company. Curtailments shall normally occur for reasonable testing requirements, at such times when the Company expects to incur a system peak in excess of its MISO (or successor organization) accredited generating capability (less the required planning reserve) and at such other times when, in the Company's opinion, the reliability of the Company or MISO systems are endangered. Curtailments shall normally not occur due to high energy costs. Curtailments shall normally occur for capacity related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service Customers (those loads that meet the requirements as specified in the MISO (or successor organization) procedure for the certification of interruptible demand). Unless agreed to in advance by the Customer, the Company shall not make additional non-firm off-system energy sales that would, if made, require curtailment of Incremental Production Service.

10. The Customer shall pay any and all penalties or other costs incurred by the Company if the Customer fails to reduce its metered demand to the IPST or the requested reduction level (but not less than the IPST) within 30 minutes of receiving such notice from the Company. The penalties or other costs shall be divided pro rata between those Customers that did not curtail service as requested by the Company.

11. The Company shall reserve the right to discontinue service under this Rider to Customers who fail to curtail service as requested by the Company.

12. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any curtailment of service.

Additional Service Conditions for Renewable Surplus Periods

13. Upon notification from the Company, Customer may exceed 110% of the IPST for a duration determined at the sole discretion of the Company. The Customer shall be given, whenever possible, information regarding the probable time and duration of Renewable Surplus Periods the calendar day prior to any such period. Notice may also be given with at least a 30 minute notice.

14. The duration and frequency of Renewable Surplus Periods shall be at the sole discretion of the Company. Renewable Surplus Periods may occur during times of high renewable generation or low MP system load.

15. The Company may cancel Renewable Surplus Periods with 30 minutes notice if MISO or MP system conditions change.

RIDER FOR RELEASED ENERGY

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74. Application of this Rider and establishment of Released Energy Credit shall be at the sole discretion of Company and participation by Customer is voluntary.

RATE MODIFICATIONS

Energy Credit for Off-System Sales
Customer shall receive a credit during any Billing Month in which Customer and Company have cooperated to make an off-system energy sale. If the energy made available for sale is associated with Customer's Firm Large Power Service requirement, the Released Energy Credit shall equal a negotiated amount based on the off-system energy sale price, less (i) Company's highest firm energy costs, (ii) and all Midcontinent Independent System Operator (MISO) costs for each hour that such sales opportunity occurs.

Energy Credit for Avoided Energy Purchases
Company may request, and Customer may voluntarily reduce, Customer's energy requirement during times when Company anticipates purchasing energy to serve Firm Energy requirements, thereby enabling Company and its customers to avoid higher-cost energy purchases. Company shall provide Customer a Released Energy Credit for the reduced energy usage, such credit to not exceed the avoided cost for the hours of the release. The Released Energy Credit shall equal a fair market value for the hours of the release.

The Released Energy Credit shall be allowed as a recoverable cost for Fuel and Purchased Energy Rider purposes.

CONDITIONS

1. Customer may not purchase Large Power Incremental Production Service ("IPS") as established under the Rider for Large Power Incremental Production Service while participating in Released Energy Credit opportunities.

2. If Customer makes energy available for sale and the identified released energy sale or avoided energy purchase is not actually completed (for example, due to transmission constraints), the Released Energy Credit shall be zero. In the event that a scheduled released energy sale or avoided energy purchase is not completed or the terms and conditions change, Company shall notify Customer of such change as soon as possible.

3. Company shall establish and administer procedures to ensure actual and verifiable Customer load reductions occur when energy is released for sale or an avoided energy purchase is completed.

RIDER FOR RELEASED ENERGY

4. When Released Energy Credit opportunities are anticipated, Company shall provide advance notice, if possible, of the approximate margins or available energy purchase costs and hours of sale or purchase opportunity available to Customers who have indicated interest. Opportunities for voluntary load reductions will be communicated to customers primarily via email, and when possible, notice shall also be made via phone calls to individuals designated by Customer. If two or more notified customers make energy available for sale for the same time period, Company will prorate the Released Energy Credit among those customers. Released Energy Credits shall be determined for each Customer according to the amount of capacity made available for sale by each in proportion to the total amount of capacity made available by all Customers for a given time period.

5. In the event that additional released energy sales or avoided energy purchase opportunities arise during a day, Company shall provide Customers with as much advance notice as possible (via email and phone calls) to enable their participation. Credits associated with such opportunities shall be allocated to Customers on a first-come, first-served basis.

6. Customer may notify Company when Customer desires to reduce energy requirements for released energy sales or avoided energy purchase opportunities. Customer may have a "standing agreement" with Company regarding the conditions for Released Energy Credit opportunities, allowable duration, required margins, margin sharing, etc. These agreements, may be made on a customer by customer basis and shall be considered by Company without notice to other customers.

7. Energy shall be made available for sale in increments of 5 MW with a 10 MW minimum and shall be associated with actual reduced power requirements.

PENALTY FOR INSUFFICIENT LOAD CONTROL

In the event that Company has entered into a sale or purchase agreement for energy made available by a Customer, and Customer subsequently fails to maintain sufficient load control during the time(s) of the released energy sale or avoided energy purchase, Customer shall receive no credit for the time that load exceeded the specified level and shall be responsible for any and all costs incurred by Company due to such failure to control load.

RIDER FOR VOLUNTARY ENERGY BUYBACK

APPLICATION

Applicable to any Customer eligible for service under General Service Schedule 25; Large Light and Power Service Schedule 75 (and including all applicable Riders thereto); or Competitive Rate Schedules 73 or 79, and customers receiving service under contracts authorized by Minn. Stat. §216B.162 (the competitive and discretionary rate statute). Customer must be able to provide a minimum of 200 kW of curtailable demand for energy buyback transactions. Energy buyback transactions facilitate short-term off-system energy sales or assist in avoiding higher-cost energy purchases to meet Company's firm energy requirements. Application of this Rider and establishment of Buyback Energy Credit ("BEC") shall be at the sole discretion of Company. Participation by Customer is voluntary. All provisions of the applicable standard Service Schedule shall apply to service under this Rider except as noted below.

RATE MODIFICATION

Customer shall receive a BEC for any calendar month in which Customer and Company have agreed to participate in energy buyback transactions. The BEC shall occur as an adjustment on Customer's bill and shall consist of a payment per kWh for each hour subject to an energy buyback transaction.

BEC for Off-System Sales
Customer shall receive a credit during any Billing Month in which Customer and Company have cooperated to make an off-system energy sale. If the energy made available for sale is associated with Customer's Firm Service requirement, the BEC shall equal a negotiated amount based on the off-system energy sale price, less (i) Company's highest firm energy costs, (ii) and all Midcontinent Independent System Operator (MISO) costs for each hour that such sales opportunity occurs.

BEC for Avoided Energy Purchases
Company may request, and Customer may voluntarily reduce, Customer's energy requirement during times when Company anticipates purchasing energy to serve Firm Energy requirements, thereby enabling Company and its customers to avoid higher-cost energy purchases. Company shall provide Customer a BEC for the reduced energy usage, such credit to not exceed the avoided cost for the hours of the release. The BEC shall equal a fair market value for the hours of the release.

The BEC shall be allowed as a recoverable cost for Fuel and Purchased Energy Rider purposes.

RIDER FOR VOLUNTARY ENERGY BUYBACK

SERVICE CONDITIONS

1. Company and Customer shall enter into an Energy Buyback Agreement specifying the rates, and the terms and conditions, for participation in energy buyback transactions, including, but not limited to: (i) BEC calculation; (ii) period of possible energy buyback; (iii) minimum/maximum duration of each energy buyback; and (iv) commencement/ termination notice requirements.

2. Company and Customer shall agree to a typical peak kW level of operation ("Reference Operating Level"). Customer shall determine an acceptable reduced operating level for each energy buyback transaction time period ("Reduced Operating Level"). The amount of energy associated with each energy buyback transaction shall be equal to the difference between Customer's Reference Operating Level and the Reduced Operating Level multiplied by the hours of curtailment at a load factor mutually agreed to by Company and Customer.

3. Company shall notify Customer of energy buyback opportunities primarily via email, and when possible, notice shall also be made via phone calls to individuals designated by Customer. Alternatively, Customer may notify Company when Customer desires to reduce energy requirements for energy buyback transactions.

4. Under the terms of the Energy Buyback Agreement, at Company's request, Customer shall curtail down to the Reduced Operating Level for a duration as required by Company, such duration not to exceed the maximum number of curtailment hours agreed to by Company and Customer. Company shall establish and administer procedures to ensure actual and verifiable Customer load reductions occur when energy is made available for sale or an avoided energy purchase is completed.

5. Customer shall pay Company the installed cost of any additional facilities (e.g., metering, protective devices for interconnection with Company's system, etc.) required to participate in energy buyback transactions under this Rider.

6. If Customer makes energy available for sale and the identified off-system energy sale or avoided energy purchase is not actually completed (for example, due to transmission constraints), the BEC shall be zero. In the event that a scheduled off-system energy sale or avoided energy purchase is not completed or the terms and conditions change, Company shall notify Customer of such change as soon as possible.

7. In the event that Company has entered into a sale or purchase agreement for energy made available by Customer, and Customer subsequently fails to maintain sufficient load control during the time(s) of the buyback energy sale or avoided energy purchase, (i) Customer shall receive no credit for that calendar month in which the curtailment failure occurred, and (ii) Customer shall be responsible for any and all costs incurred by Company

RIDER FOR VOLUNTARY ENERGY BUYBACK

due to such failure, including but not limited to: (a) penalties imposed upon Company by the Midcontinent Independent System Operator (MISO) or any other entity, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases.

8. Company shall not be liable for any loss or damage caused by or resulting from any curtailment of service at Customer's facility undertaken in response to BEC.

RIDER FOR VOLUNTARY RENEWABLE ENERGY

APPLICATION

Application to customers taking service under all retail rate schedules. All provisions of the applicable standard Service Schedule shall apply to renewable energy service under this Rider except as noted below. The renewable energy service provided under this schedule is subject to the availability of renewable energy designated to it, as determined by the Company, and is made available on a first-come, first-served basis. “Renewable energy” means electricity generated through use of any of the following resources: wind, solar, geothermal, hydro, trees or other vegetation, or landfill gas. Participation by the Customer is voluntary.

RATE MODIFICATIONS

The Rates (Monthly) and all adjustments included in the applicable service Schedule shall apply. Additionally, the Customer shall pay a monthly renewable energy surcharge for each kWh of renewable energy nominated, and shall receive a credit for the rate-class-specific monthly Fuel and Purchased Energy Charge.

DETERMINATION OF THE RENEWABLE ENERGY SURCHARGE

The renewable energy surcharge shall be based on the total program costs including the sum of:

[b] The cost of renewable energy that will supply the program,

[c] The delivery costs,

Divided by

[a] The expected annual energy output.

The renewable energy surcharge will be recalculated annually to reflect power supply costs. An example of the calculation is shown below in Appendix 1.

Renewable Energy Surcharge

$0.03900 per kWh – All Customer Classes

The charge per kWh is in addition to the applicable Service Schedule currently serving the customer. All charges under existing tariffs remain in effect.

RIDER FOR VOLUNTARY RENEWABLE ENERGY

SERVICE CONDITIONS

1. The Customer may nominate between 25% and 100% of their monthly kWh use.

2. The Customer shall take service under this Rider for no less than one year. Service shall continue thereafter until and unless the Customer notifies the Company that service under the Rider is to be terminated.

Appendix 1

MINNESOTA POWER
Sample of
Renewable Rate Pricing Calculation

Power Supply Cost:	
[a] Expected annual energy output (PPA)	xx kWh
[b] Cost of Renewable energy to supply program (per PPA guidelines)	$xx
[c] Delivery Cost of renewable energy	$xx
[d] Renewable Energy Surcharge ([b] + [c]) / [a]	$xx per kWh

RIDER FOR CITY OF LONG PRAIRIE FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Long Prairie, except bills for electric service to property owned by the City of Long Prairie.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Long Prairie Franchise Fee assessment in the amount of:

$1.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Long Prairie Franchise Fee assessment collected will be passed along to the City of Long Prairie.

RIDER FOR CITY OF LITTLE FALLS FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Little Falls, except bills for electric service to property owned by the City of Little Falls.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Little Falls Franchise Fee assessment in the amount of:

$1.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Little Falls Franchise Fee assessment collected will be passed along to the City of Little Falls.

RIDER FOR CITY OF HERMANTOWN FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Hermantown, except bills for electric service to property owned by the City of Hermantown and property owned or leased by Company.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Hermantown Franchise Fee assessment in the amount of:

$2.00 per month for each residential electric service agreement; and
$2.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Hermantown Franchise Fee assessment collected will be passed along to the City of Hermantown.

RIDER FOR CITY OF PARK RAPIDS FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Park Rapids, except bills for electric service to property owned by the City of Park Rapids.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Park Rapids Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Park Rapids Franchise Fee assessment collected will be passed along to the City of Park Rapids.

RIDER FOR CITY OF AURORA FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Aurora, except bills for electric service to property owned by the City of Aurora.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Aurora Franchise Fee assessment in the amount of:

$2.00 per month for each residential electric service agreement; and
$2.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Aurora Franchise Fee assessment collected will be passed along to the City of Aurora.

RIDER FOR DISTRIBUTED GENERATION SERVICE

APPLICATION

To any Customer taking service under one of Company's following standard rate schedules: Residential Service (Schedule 20), Residential Dual Fuel Interruptible (Schedule 21), Commercial/Industrial Dual Fuel Interruptible (Schedule 26), General Service (Schedule 25), Large Light and Power Service (Schedule 55, 75), Municipal Pumping Service (Schedule 87) and Large Power Service (Schedule 54, 74) and who has entered into Minnesota Power's standard interconnection agreement with the Company for the operation of the on-site interconnection of a Distributed Energy Resource operating in parallel with the Company's distribution system. The Distributed Energy Resource must be:

a. an operable, permanently installed or mobile generation facility serving the customer receiving retail electric service at the same site; and

b. fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10 MW of interconnected capacity at a point of common coupling to Company's distribution system. The interconnection and operation of Distributed Energy Resources at each point of common coupling shall be considered as a separate application of the Rider.

Service under this Rider shall be required for any Customer who meets the Application criteria in the previous paragraph, subject to the following exceptions: (i) any Customer who takes service, as applicable, under Company's Rider for Parallel Generation as established under Minnesota Rules Chapter 7835 – Cogeneration and Small Power Production; or (ii) any Customer, in lieu of service under this Rider, who pursues reasonable transactions outside this Rider as agreed to by Company and Customer.

Customer shall execute an electric service agreement and a power purchase agreement with Company for service under this Rider. The minimum term of service taken under this Rider shall be one (1) year or such longer period as may be required under the electric service agreement. Service under this Rider is subject to Company's Electric Service Regulations and any other rules as applicable. All provisions of the applicable standard rate schedule shall apply to service under this Rider except as noted below.

TYPE OF SERVICE

Output of the Distributed Energy Resource shall be provided at 60 hertz and at the voltage and phase relationship specified under Company's applicable standard rate schedule for service to Customer or as agreed to by Company and Customer.

RIDER FOR DISTRIBUTED GENERATION SERVICE

RATE (Monthly)

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard rate schedule:

Service Charge: $15.83

Capacity/Energy Credits:

Customer may sell all the energy produced by the Distributed Energy Resource to Company, use all the Distributed Energy Resource energy to meet its own electric load requirements or use a portion of the energy from the Distributed Energy Resource and sell the remaining to Company.

Company shall purchase all capacity and energy made available by Customer from the Distributed Energy Resource. Such capacity and energy shall be purchased by Company under the rates, terms and conditions for such purchases as established by Company in a power purchase agreement with Customer.

Capacity Credits shall only be provided on that capacity available to Company which meets the accreditation requirements of the Midcontinent Independent System Operator (MISO) or successor organization.

Capacity and Energy Credits shall be based on Company's calculation of avoided capacity and energy costs. The Capacity Credits in effect at the time Customer enters into a power purchase agreement with Company shall remain in effect for the length of the agreement. Energy Credits for use under the power purchase agreement shall vary by month and time period (on-peak and off-peak) and shall be updated annually for the upcoming calendar year. Upon written request by Customer and after Customer signs a confidentiality agreement, Company shall provide Customer the current schedule of Capacity and Energy Credits.

Delivery Charge ($/kw):

Company may require any Customer with a Distributed Energy Resource of 1 MW or greater nameplate capacity rating to pay a Delivery Charge for all capacity and energy made available by Customer from the Distributed Energy Resource. Such Delivery Charge shall compensate Company for any additional distribution, transmission and ancillary services not included under this Rider provided by Company to Customer through Company's participation in the MISO or successor organization. For applying the Delivery Charge, the capacity shall be determined during the 15-minute period of Customer's greatest capacity delivered to Company during the billing month.

RIDER FOR DISTRIBUTED GENERATION SERVICE

Distribution Credits:

If the installation of the Distributed Energy Resource results in Company delaying or avoiding distribution investment, Company shall provide Distribution Credits to Customer that reflect the avoided distribution cost.

Company shall provide, upon Customer's written request, a list of substation areas or feeders that could be likely candidates for Distribution Credits as determined through Company's normal distribution planning process. Upon receiving an application from Customer for the interconnection and operation of a Distributed Energy Resource, Company shall perform an initial screening study to determine if the project has the potential to receive Distribution Credits. Customer shall be responsible for the cost of such screening study. If Company's initial study shows that there exists potential for Distribution Credits, Company shall, at its own expense, pursue further study to determine the Distribution Credits, as part of its annual distribution capacity study.

Line Loss Credits:

If the installation of the Distributed Energy Resource results in Company avoiding additional line losses, Company shall provide Line Loss Credits to Customer that reflect the additional line loss savings.

Company shall perform, upon Customer's written request, a specific line loss study to determine if the project has the potential to receive Line Loss Credits. Customer shall be responsible for the cost of such line loss study.

Renewable Credits:

If Company's purchase of capacity and energy from the Distributed Energy Resource results in Company meeting a requirement to obtain renewable capacity and energy, Company shall provide Renewable Credits to Customer that equal the additional avoided cost of the renewable addition or purchase. The purchase price of such Renewable Credits shall be net of payment for capacity and energy identified above.

In the event that Customer producing the power receives renewable credits, (that is, the Customer is paid by the Company the avoided cost of renewable energy purchases), then the transaction represented by the power purchase agreement will constitute a transfer from the Customer to the Company of the property rights, for those renewable attributes specific to the renewable energy generated by the Customer and for which the Company paid renewable credits.

Customer may receive either renewable credits or tradable emission credits but not both.

RIDER FOR DISTRIBUTED GENERATION SERVICE

Tradable Emission Credits:

If Company's purchase of capacity and energy from the Distributed Energy Resource results in Company receiving an economic value associated with tradable emissions, Company shall provide Tradable Emission Credits to Customer that equal the credit revenues associated with the Distributed Energy Resource of such Tradable Emission Credits received by Company. Customer may receive either renewable credits or tradable emission credits but not both.

In the event that Customer producing the power receives tradable emission credits, then the transaction represented by the power purchase agreement will constitute a transfer from the Customer to Company of the property rights, if any, for those tradable emission credits received by Customer and for which Company paid tradable emission credits.

SERVICE CONDITIONS

1. All electricity delivered to Company by Customer shall be measured by one or more meters installed at a single point of common coupling or as determined by Company. Company's meter for distributed generation service shall measure the flow of capacity and energy from Customer to Company only. Any flow of capacity and energy from Company to Customer shall be separately metered.

2. Service shall be provided under this Rider if Company has sufficient capacity available in existing transmission and distribution facilities to provide such service at the location where service is requested.

3. Customer shall pay Company the installed cost of any additional required facilities which are not supported by this Rider.

4. Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

PROCESS AND TECHNICAL DOCUMENTS AVAILABILITY

Company Distributed Energy Resource process and technical documents are available at www.mnpower.com or by contacting Company at 1-800-228-4966 or 30 West Superior Street, Duluth, MN 55802.

RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	$0.74 per kW-month for all Billing Demand kW and 0.097¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.250¢ per kWh for all kWh

RIDER FOR TRANSMISSION COST RECOVERY

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	$0.36 per kW-month for all Billing Demand kW and 0.047¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.195¢ per kWh for all kWh

RIDER FOR CITY OF NASHWAUK FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Nashwauk.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Nashwauk Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Nashwauk, which is currently 1.5% of the total bill excluding sales taxes. The fee is listed on the bill as "Nashwauk Franchise Fee (1.5%)" and is effective as of February 10, 2011.

100% of the City of Nashwauk Franchise Fee assessment collected will be passed along to the City of Nashwauk.

RIDER FOR FOUNDRY, FORGING AND MELTING CUSTOMERS

APPLICATION

Applicable to any customer in the Foundry, Forging, and Melting Industry, as determined by Company, taking service under Large Light and Power Service (Schedule 75).

Customers taking service under this Rider may not also take service under the Rider for General Service/Large Light and Power Interruptible Service.

The term of service under this Rider shall be no less than one year. Customers must provide 30 days advance notice to Company prior to taking service under this Rider or discontinuing service under this Rider after at least one year of service.

This Rider shall apply to the entire electric service requirements on Customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

RATE MODIFICATION

Demand Charge Credit: For each month that service is taken under this Rider, the Customer shall receive a billing credit of $3.00 per kW of Billing Demand.

Price Recall Energy: 200 Hours of Price Recall Energy per calendar year will be billed at Company's sole discretion subject to the following conditions.

- Minimum of three hours duration per price recall period.
- Price Recall hours will be limited to 6 a.m. to 10 p.m. Central Prevailing Time with the exception of time periods when Midcontinent Independent System Operator (MISO) (or successor) has declared an alert or emergency for the Minnesota Power area.
- Minnesota Power will provide day-ahead email notice by 4 p.m. Central Prevailing Time on the day prior to the price recall period(s). The notice will indicate the start and stop times for the price recall period(s) and estimated prices during these price recall period(s).
- Customer has the option to curtail load or to continue normal operations during the price recall period.
- Price Recall energy usage will be billed at 110% of the Company's hourly incremental energy costs during the time of the price recall period. Incremental energy costs are determined after assigning lower cost energy to all firm retail and firm wholesale customers including all inter-system pool sales which involve capacity on a firm or participation basis.

PILOT RIDER FOR LARGE LIGHT AND POWER TIME-OF-USE SERVICE

APPLICATION

Applicable to any customer taking service under Large Light and Power Service Schedule 75 with total power requirements of at least 3,000 kW. Application of this Rider shall be at the sole discretion of Company. All provisions of the Large Light and Power Service Schedule shall apply to the Time-of-Use service under this Rider except as noted below. Participation by customer is voluntary.

Customers taking service under this Rider may not also take service under the Rider for Parallel Generation or the Rider for General Service/Large Light and Power Interruptible Service.

RATE MODIFICATION

The monthly rate will be modified as follows:

Demand Charge	
For the first 100 kW or less of On-Peak Billing Demand	$1,050.00
All additional On-Peak Billing Demand ($/kW)	$9.75
Off-Peak Demand in excess of On-Peak Billing Demand ($/kW)	$4.50
Super Off-Peak Demand in excess of Off-Peak Billing Demand ($/kW)	$0.00
Transmission Demand Charge ($/kW)	
On-Peak Transmission Demand	$6.07
Energy Charge	
On-Peak kWh (¢/kWh)	7.071¢
Off-Peak kWh (¢/kWh)	4.715¢
Super Off-Peak kWh (¢/kWh)	3.538¢

Modified Determination of Billing Demand

On-Peak Billing Demand shall be the kW measured during the 15-minute period of the customer's greatest On-Peak use during the month, as adjusted for power factor, except that On-Peak Billing Demand will not be less than 75% of the greatest adjusted On-Peak demand during the preceding eleven months, nor shall it be less than any Minimum Contract Demand that may be specified in customer's Electric Service Agreement.

The Off-Peak Billing Demand is defined as the difference between the maximum kW measured during the 15-minute period of the customer's greatest use (On-Peak or Off-Peak) during the current month, as adjusted for power factor, and the On-Peak Billing Demand.

The Super Off-Peak Demand is defined as the difference between the maximum kW measured during the 15-minute period of the customer's greatest use (On-Peak, Off-Peak,

PILOT RIDER FOR LARGE LIGHT AND POWER TIME-OF-USE SERVICE

or Super Off-Peak) during the current month, as adjusted for power factor, and the On-Peak and Off-Peak Billing Demand.

SERVICE CONDITIONS

1. On-Peak, Off-Peak, and Super Off-Peak Periods Defined: The On-Peak time period shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Super-Off Peak period shall be defined as 11:00 p.m. to 5:00 a.m. CPT. The Off-Peak time period shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

2. At the end of the first year following the initial date when any customer takes service under this Rider, the applicability, rate modification, and service conditions will be evaluated for potential modification. The Rider will continue in effect after the initial year until it has been modified or cancelled based on the evaluation of the pilot.

3. The term of service under this Rider shall be no less than one year unless the pilot offering is terminated prior to the conclusion of customer's first year of service.

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

APPLICATION

Applicable to any Residential Service Customer taking service under Rate Code 20 (General) or Rate Code 22 (Space Heating) who is approved as qualified for the Low Income Home Energy Assistance Program (LIHEAP) by a designated social service agency (Agency) within Company's service territory during the program year (October 1 to September 30). Customers must receive certification annually through authorized Agency to be eligible for this Rider. A qualification exception applies for customers who initially self-declare as low income. Continued eligibility for the CARE program, beyond the initial exception, would be subject to customers requesting and being approved for LIHEAP within one year of their low income self-declaration.

DEFINITIONS

SENIOR Customers:
Seniors are those age 62 or older, as determined through the LIHEAP qualification and/or Low Income Self-Declaration process.

DISABLED Customers:
Disabled are those determined as disabled through the LIHEAP qualification and/or Low Income Self-Declaration process.

LEGACY CARE Customers:
Customers enrolled in the CARE Program as of September 30, 2019 or prior to the initial offering of the flat and affordability discounts under this Rider, whichever is later.

RATE MODIFICATION

All provisions of the Residential Service Schedule shall apply except as modified below:

FLAT DISCOUNT

Eligible Senior, Disabled, and / or Legacy CARE customers receive a $20 flat discount in each monthly billing period.

AFFORDABILITY DISCOUNT

Eligible Senior and / or Disabled Customers Under 62 Years of Age with no Disability, and Customers with certified medical circumstances:

A customer using more than 3% of their annual household income for electric bill payments may be eligible for the Company's affordability discount. The Company will offer customers with the lowest income, and a history of high electric consumption, an affordability discount

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

with the goal of keeping a household's annual energy burden within 3% of its income, on average. The affordability discount will be applied as a monthly percentage discount on bill.

LOW-INCOME AFFORDABILITY PROGRAM SURCHARGE

For Customers taking service under: Residential Service (Rate Code 20, 22, and 23) except those residential customers who are qualified for LIHEAP, General Service (Rate Code 25), Large Light & Power (Rate Code 75), Large Power (Rate Code 74), and Non-Contract Large Power (Rate Code 78) there shall be added to each service agreement, as designated above, on their monthly bill, a Low-Income Affordability Program Surcharge as specified below:

Residential (Except LIHEAP-qualified)	$2.41
General Service	$4.01
Large Light & Power	$26.74
Large Power	$1,826.31

SERVICE CONDITIONS

1. In order to determine customer eligibility for this Rider, the Company will review customer's LIHEAP approval and/or Low Income Self-Declaration status, Customer billing information, approved LIHEAP benefits, household income, and / or arrears.

2. For Legacy CARE and Affordability Discount Customers, any past due bills for electric service will be spread over a maximum of 24 months and shall be put in a 24-month payment arrangement under the Arrearage Forgiveness program.

3. Customers taking service under this Rider will be encouraged to participate in Minnesota Power's energy conservation programs.

4. Customers must be LIHEAP eligible by May 1 of each program year to continue receiving service under this Rider. The program year starts October 1 and ends September 30 of the following year.

5. Customers who become eligible through the Low Income Self-Declaration process must request and be determined eligible for LIHEAP within one year of their initial low income self-declaration in order to remain eligible for this Rider.

6. Customer must maintain an active account registered under Customer's name with the Company to be eligible for this Rider.

7. Qualified Customers are eligible to receive a discount under this Rider at only one residential location at any one time, and the Rider applies only to a qualified

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

Customer's primary residence. This Rider will not be available when, in the opinion of the Company, the Customer's residency or occupancy is of temporary nature.

8. It is the Customer's responsibility to notify the Company if there is a change of address or eligibility status.

9. Application of this Rider shall be prospective, and the Rider discount shall not be applicable to past due bills.

10. If the participating Customer misses two consecutive payments, the Customer will be removed from this Rider and ineligible until the next program year, at the Company's discretion. The Customer will become subject to standard collection activities for any past due amounts.

11. Refusal or failure of a Customer or Agency to provide documentation of eligibility acceptable to the Company may result in Customer removal from this Rider.

12. Customer may be re-billed for periods of ineligibility under the applicable standard rate schedule.

13. This Rider shall meet the conditions of Minnesota Statutes, Chapter 216B.16, Subd. 15 on low income affordability programs.

ARREARAGE FORGIVENESS CONDITIONS

1. Current Legacy CARE and Affordability Discount participants with past-due arrears balances that satisfy Service Condition 1 are eligible for Arrearage Forgiveness.

2. Potential Arrearage Forgiveness applies to outstanding arrears at the time of CARE enrollment or as of the effective date of the Arrearage Forgiveness component, whichever is later.

3. The Arrearage Forgiveness shall in no event exceed the outstanding arrears balance.

4. The Company shall total the amount of arrears payments made by all CARE customers each month, and based on available funds in the CARE Rider Tracker, shall determine the percentage matching rate and shall match each Customer's monthly paid arrears amount by applying the determined percentage to reduce arrears in the same month. The initial matching rate will be 100 percent.

5. In the event a Customer applies, qualifies and receives fuel assistance, the fuel assistance amount may be used to pay the arrears amount. The Company shall not match amounts paid by a third party; however, any amount of arrears paid by the Customer any

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

month shall be matched by the Company by applying the percentage of reduction in place as stated in Arrearage Forgiveness Condition 4 above.

6. If a Customer has new arrears, it means the Customer has missed at least two consecutive payments, therefore, Service Condition 10 applies, and the Customer shall no longer be eligible for the CARE Program or the Arrearage Forgiveness component.

RIDER FOR CITY OF SILVER BAY FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Silver Bay, except bills for electric service to property owned by the City of Silver Bay, for the period from January 1, 2014 to December 31, 2024.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Silver Bay Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$3.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Silver Bay Franchise Fee assessment collected will be passed along to the City of Silver Bay.

RIDER FOR CITY OF HOYT LAKES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Hoyt Lakes, except bills for electric service to property owned by the City of Hoyt Lakes, for the period from October 2015 to October 2035.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Hoyt Lakes Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$3.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Hoyt Lakes Franchise Fee assessment collected will be passed along to the City of Hoyt Lakes.

RIDER FOR SOLAR ENERGY ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79. This Rider shall be applicable to customers who are not exempt from Solar Energy Standard obligations under Minnesota Statutes, Section 216B.1691, subd. 2(f), hereby defined as Solar-Paying Customers.

SOLAR ENERGY ADJUSTMENT

The Solar Energy Adjustment (SEA) shall be added to or deducted from each Solar-Paying Customer's monthly bill in an amount per kilowatt-hour determined as described below.

The SEA shall be calculated each month using data for the first two of the preceding three months as follows:

(a) Cost of solar energy purchased,
(b) Plus a credit for fuel and purchased energy costs included in the Rider for Fuel and Purchased Energy Adjustment (FPE Rider). The credit is an adjustment for cost already collected through the FPE Rider, including the Time of Generation Adjustment (TOGA). This credit is determined by multiplying the solar energy generation by the TOGA-adjusted FPE Adjustment (e) and adding the TOGA (d) as defined below.

Total of (a) and (b) shall be divided by the total kilowatt-hour sales for Solar-Paying Customers for the first two of the preceding three months.

TIME OF GENERATION ADJUSTMENT

The TOGA shall quantify the value of the time of generation for solar energy in order to compensate Solar-Paying Customers based on the time the solar energy is produced. The TOGA shall be added to the FPE cost and the resulting TOGA-adjusted FPE Adjustment shall be calculated in the FPE Rider as follows and applied to all customer energy usage:

(c) Calculate the FPE Adjustment without solar ($/MWh) by dividing the FPE costs excluding solar costs ($) by the non-solar energy generation (MWh);
(d) Calculate the TOGA by multiplying the TOGA Factor as determined below by the solar energy generation and by the FPE Adjustment without solar;
(e) Calculate the TOGA-adjusted FPE Adjustment by adding the TOGA to the FPE costs excluding solar costs and dividing this sum by non-solar energy generation.

RIDER FOR SOLAR ENERGY ADJUSTMENT

TIME OF GENERATION ADJUSTMENT FACTOR

The TOGA Factor shall be determined as follows:

(f) Calculate the simple average of actual non-solar energy cost ($/MWh) for the first two of the preceding three months by dividing total monthly costs of non-solar generation by total monthly non-solar MWh sales;
(g) Calculate the total hourly solar energy generation (MWh) for the first two of the preceding three months;
(h) Calculate the weighted average solar generation cost by multiplying each hourly projected avoided energy cost ($/MWh) by the associated solar energy generation amount (MWh) and then summing the total for the month ($);
(i) Calculate the weighted average solar energy generation cost ($/MWh) by dividing (h) by (g);
(j) Calculate the TOGA Factor by dividing (i) by (f) and subtracting 1.

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

APPLICATION

This Rider shall be applicable on an optional basis to any retail customers who are not exempt from Solar Energy Standard obligations under Minnesota Statute § 216B.1691, subd. 2(d).

RATE (Monthly)

The Customer may choose one of the following options for charges and credits which shall be applicable in addition to all charges for service being taken under Company's standard rate schedule.

Option 1. Upfront Payment per kW

Customer shall pay a one-time subscription charge for each contracted kW solar block. A solar block under this rider represents 1 kW of capacity. Customer will receive a monthly energy kilowatt-hours (kWh) credit for the solar energy produced by each solar block. The charge and credit shall be as follows:

kW Block Charge	$2,132.15 per subscribed block.
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Option 2. Monthly Subscription per kW

Customer shall pay a monthly subscription charge for each contracted kW solar block. A solar block under this rider represents 1 kW of capacity. Customer will receive a monthly energy (kWh) credit for the solar energy produced by each solar block. The charge and credit shall be as follows:

kW Block Charge	$15.62 per subscribed block per month
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Option 3. Fixed Charge per kWh

Customer shall pay a charge for the energy the customer's subscribed portion of the solar garden generates. The charge shall be as follows:

Fixed kWh Charge	$0.1115 per kWh

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Monthly kWh Credit
The monthly energy credit (kWh) shall also be applied to the Company's following volumetric riders on the customer's monthly bill; Rider for Fuel and Purchased Energy Adjustment, Rider for Conservation Program Adjustment, Rider for Renewable Resources, Rider for Transmission Cost Recovery, Rider for Boswell Unit 4 Emission Reduction, and other Commission-approved volumetric riders on the customer's monthly bill.

Subscription Prices Calculation
The subscription prices above are calculated incorporating a $0.002 Solar Renewable Energy Credit (S-REC).

SERVICE CONDITIONS

1. To participate in the Community Solar Garden Pilot Program, a customer must submit an application to Minnesota Power's Renewable Programs Department. Each customer's subscription will be capped at 120 percent of the customer's average annual energy usage in the twelve months prior to the date of the customer's application to this program, but not to exceed 20 kW per Service Agreement.

2. Total participation of non-residential customers will be limited to no more than 50 percent of the total solar garden capacity during the initial offering.

3. Each customer participating in the Community Solar Garden Pilot Program will sign a 25-year contract which specifies the price the customer will pay for solar energy, aligned with the timeframe of the Company's power supply resource acquisition.
   a. Customers who choose Option 2 or Option 3 will have the ability to leave the program at any time. These customers may either have their subscriptions reassigned to another qualifying participant or relinquish their subscription to Minnesota Power.
   b. Customers who choose Option 1 will also have the opportunity to reassign or relinquish their subscription. Because customers on this option have made a significant upfront investment, if they cannot sell or transfer the subscription to another qualifying participant in a private transaction, Minnesota Power will purchase the subscription back from them at a predetermined amount that will decline by 4 percent per year from the original upfront payment amount.
   c. For cancelled subscriptions, Minnesota Power shall pay subscribers for the remaining kWh credits at the monthly average amount for the previous twelve months, plus any payment for S-RECs associated with the unused kWh credits.

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

4. Customers will not receive any cash payments or monetary credits in this program, with the exception of any payments resulting from subscription cancellation. Any excess energy shall be carried forward in the form of a kWh credit to the customer's subsequent bills for a period of five years. During this five-year period, the Company will evaluate what limits, if any, should be placed on the rolling over of energy credits. Banked credits are not transferable to other customers through subscription transfers.

RIDER FOR BACKUP GENERATION SERVICE

APPLICATION

To any Customer taking service under one of Company's following standard rate schedules: General Service (Schedule 25), Large Light and Power Service (Schedule 75), and Municipal Pumping Service (Schedule 87) who contract for backup generation service of at least 50 kW for an initial period of ten years or more. Program participation will be limited to 10 MW total customer load.

RATE (Monthly)

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedule:

I. Customers taking firm service under this Rider will have an additional charge for backup generation applied to the customer maximum 15-minute demand as shown below:

   a. The firm demand charge will be applied each month to the demand specified in customer's Backup Generation Service Agreement.

   b. Redundant on-site backup generation capacity is available from Company if the added capacity is available to the Company under the existing terms of the tariff. Redundant backup generation service will be subject to an additional demand charges shown below applied to the capacity of the redundant generator. Any generator(s) installed in addition to generator(s) deemed appropriate by the Company to serve the customer's maximum 15-minute demand will be considered redundant under this tariff.

II. Customers taking interruptible service under this Rider will have an additional charge for backup generation applied to the agreed upon minimum contract firm demand level.

III. Firm demand charges are as follows:

   A monthly per kW Firm Demand Charge shall be applied to the Customer maximum 15-minute demand, as defined in customer's Backup Generation Service Agreement.

SERVICE CONDITIONS

1. A customer receiving service under this Rider must enter into a contract that identifies the size of the generator specified and installed by the Company, the customer's expected annual maximum load, and the monthly firm demand charge. The company will have discretion as to the size and number of generators required to meet customer needs under this Rider.

2. If after five years the maximum customer 15-minute demand level falls below 75% of the contracted demand agreed upon in the customer's Backup Generation Service Agreement, the Company will determine whether to remove the generator and

discontinue Backup Generation Service at that site or retain service and charge for this Rider based on the minimum contracted demand level as specified in the customer's Backup Generation Service Agreement. Generator size, use of the generator elsewhere, future customer demand, and special usage circumstances will be considered in making this decision.

3. A customer that receives electric service through more than one distribution service feed at a single location (premise) may choose to take backup service under this Rider for all or only selected service feeds at that location. The Company may require the customer to pay in advance of installation for any additional metering or measurement equipment necessary for the customer to take backup service for less than the entire premise.

    a. For firm service customers, backup generation service must be taken at a minimum of the entire load at each distribution service chosen. For purposes of this Rider, the customer demand will be the greatest rate at which electrical energy has been used for the distribution service feeds during any 15 minute period, for a minimum, of the preceding 24 billing months. For purposes of this Rider, the minimum demand determined by Company will consider anticipated load changes and/or unusual operation circumstances.

    b. For interruptible and supplemental service customers, backup generation service must be taken for the full amount of the customer's firm load. For purposes of this Rider, the contract firm load will be the customer's contract firm load in effect at the time the customer enters into the Backup Generation Service Agreement with the Company.

4. The contract will have an initial minimum term of ten years. At the end of the initial term the contract will be automatically renewed on an annual basis unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the contract term.

5. The authorized rate in effect at the time the initial contract term begins for a customer will remain fixed for that customer for the entire initial contract term, regardless of other changes that may from time to time be approved by the Minnesota Public Utilities Commission. At the end of the initial term, service will be charged at the authorized rate in effect at the time.

6. The Company will work with the customer to determine where to install the generator(s) and associated equipment. The facilities will comply with National Electric Code, National Electric Safety Code, Minnesota electric code and all applicable, local ordinances, and accepted engineering and planning practices and will be connected to the Company's system over the most direct route as determined by the Company. The Company is responsible for maintaining facilities in compliance with applicable regulations and ordinances that may change over the term of the contract.

RIDER FOR BACKUP GENERATION SERVICE

7. The customer will provide or will be responsible for the cost of all right-of-way easements and building permits necessary for the Company to connect the generator to the Company's system and to install, maintain, or replace distribution facilities where necessary.

8. The customer will supply the space for the generator(s) and a concrete pad as specified by the Company. The customer is responsible for clearing and grading the property and building the pad to specifications required by the Company.

9. The Company is responsible for installation of the generator and associated electrical interconnect. The customer is responsible for the cost of restoration of the property after the Company has completed installation where applicable.

10. If the generator installation requires nonstandard service facilities or if the customer requests nonstandard facilities or design, including but not limited to aesthetics, noise attenuation, exhaust ventilation, or location on the customer's premise, the customer will be required to make payment arrangements satisfactory to the Company for the cost of the facilities in excess of standard design.

11. The customer will be required to make the Company equipment available and permit entry upon the property by Company or contracted personnel at all times for the purposes of testing, maintenance, and replacement of the equipment. The Company will be responsible for testing the generator at least once a year to ensure the equipment is in proper working condition.

12. The Company reserves the right to operate the generator to meet system load requirements. The Company will coordinate these operations to accommodate customer business requirements if possible.

13. The availability of service under this Rider may be limited at the discretion of the Company. Service under this Rider may be refused if the Company believes the customer presents an unacceptable credit risk or cannot provide or meet suitable generator siting requirements, including physical and environmental restrictions and liability limitations.

14. Energy furnished under this Rider will not be resold by the Customer.

15. The customer may request that Company’s on-site generation be operated during specific times. The Company will comply with Customer’s request provided the additional hours of operation do not adversely impact any permits or other regulatory requirements. The customer shall pay the replacement cost of all fuel consumed during the test. The Company will pay all associated fuel costs of the generator for standard operation.

16. Company shall not be held liable for loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

RIDER FOR BACKUP GENERATION SERVICE

17. If the customer chooses to end service under this Rider prior to the end of the current contract, the customer must pay 50% of the demand specified in customer's Backup Generation Service Agreement for the remaining term of the Backup Generation service obligation.

RIDER FOR BUSINESS EXPANSION INCENTIVE

APPLICATION

Applicable to any new or expanding commercial or industrial Customer taking service under General Service (Schedule 25), Large Light and Power Service (Schedule 75), or Large Power Service (Schedule 74) and which has at least 250 kW of new or expanding load. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

Customer must complete an application for service under the Rider for Business Expansion Incentive, and service is limited to customers whose application is approved by the Company. For existing customers, at least three months of Qualified Billing Demand must occur before service under this Rider may commence.

TYPE OF SERVICE

Service shall be taken at the voltage and phase relationship specified under Company's applicable standard rate schedule for service to Customer.

RATE

The provisions of the General Service, Large Light and Power, or Large Power Service Schedule shall apply, except monthly Demand Charges (excluding the Transmission Demand Charge) for customer's Qualified Billing Demand before the application of voltage discounts, shall be reduced as follows:

Large Power Service Schedule Demand Reduction Percent:

Years:	1-3	4	5	6
Percent Reduction:	30%	15%	5%	0%

General Service and Large Light and Power Service Schedule Demand Reduction Percent:

Years:	1-3	4	5	6
Percent Reduction:	50%	25%	15%	0%

For new or existing customers, Qualified Billing Demand is the new load of 250 kW or greater at a single delivery point. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies. The demand charge reduction shall not apply during any month in which the Qualified Billing Demand is below 250 kW, unless as a consequence of documented new conservation or load control by the customer.

RIDER FOR BUSINESS EXPANSION INCENTIVE

NEW CUSTOMER QUALIFICATIONS

This Rider is available for new load that is associated with initial permanent service. To be considered a new customer for the purpose of this Rider, an applicant must demonstrate one of the following:

1. Business has not been conducted at the premises for at least three monthly billing periods prior to application; or

2. The predecessor customer is in bankruptcy and the applicant has obtained the business in a liquidation of assets sale; or

3. Customer's activities are largely or entirely different in nature from that of the previous customer.

EXISTING CUSTOMER QUALIFICATIONS

Existing customers, at an existing delivery point or new delivery point, who materially increase their use of electric service may qualify for service under this Rider, provided such material increase is the result of the addition of equipment, or expansion of the customer's facility or operations. The customer shall notify the Company in writing and document the basis for the material increase in its use of electric service. Following such notification, the Company shall review the customer's monthly billing demands. If the billing demands for each of the next three consecutive months exceed that from the comparable monthly period of the preceding year by at least 250 kW at one delivery point, the customer will be eligible thereafter to receive service under this Rider. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies. If a customer's activities are very similar to the customer's previous activities, then the customer is considered to be an existing customer whether or not the owner(s), operator(s), or manager(s) are substantially different.

ENERGY EFFICIENCY

The Company is required to conduct an energy audit for all customers taking service under this Rider, and inform the customer of the conservation programs available.

TERMS AND CONDITIONS

1. This Rider contemplates that this service shall utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required, which are not supported by this Rider.

RIDER FOR BUSINESS EXPANSION INCENTIVE

2. The minimum discount under this Rider shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the Rider is in effect.

3. The Company shall execute an Electric Service Agreement (ESA), having a minimum term of six (6) years with a minimum cancellation provision of one (1) year. The ESA shall state the increased or new load level of the customer, and the effective date of service under this Rider shall be set forth in the ESA.

ELECTRIC SERVICE AGREEMENTS

1. Every ESA and every amendment or modification of an ESA shall be approved by the Minnesota Public Utilities Commission ("Commission").

2. Every new or amended ESA shall be filed with the Commission within 30 days after signing the agreement with the Customer.

3. Every ESA filing shall include the incremental revenue and the incremental costs associated with the new ESA.

4. If no party objects to the ESA within 30 days of the filing date, the ESA is deemed approved.

RIDER FOR CITY OF UPSALA FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Upsala, except bills for electric service to property owned by the City of Upsala.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Upsala Franchise Fee assessment in the amount of:

$5.00 per month for each electric residential service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Upsala Franchise Fee assessment collected will be passed along to the City of Upsala.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74, having a minimum contract term of at least the duration of the respective demand response product, and subject to the Conditions below.

DEFINITIONS

Demand Response Billing Demand: Capacity volume associated with the Rider for Large Power Demand Response Products A and C that will receive Demand Charge Credits on a monthly basis, as specified herein.

Demand Response Contract Demand: The aggregate of Customer's accredited capacity of Products A and C under this Rider.

Firm Service Level or Targeted Demand Reduction Level: Customer's targeted demand reduction threshold that is specified when customer registers for Products A and C.

Emergency Curtailment: Requirement for participating Customers to physically reduce load to their Firm Service Level or Targeted Demand Reduction Level.

LARGE POWER DEMAND RESPONSE PRODUCTS AND CONDITIONS

There are two optional Demand Response products available to Customers. The characteristics and conditions for each product are as follows:

Large Power Demand Response Product A - Short-Term Emergency Capacity
Product A is a one-year emergency-only capacity product. A minimum one-year Demand Response commitment and one-year term remaining on Customer's Electric Service Agreement at time of selection is required for this product. Product A includes a Demand Charge Credit as detailed in the Rate section below. The Company will call on this capacity as allowed under the requirements to accredit capacity for satisfying resource adequacy requirements or to mitigate local system emergency events.

Short-Term Emergency Capacity must meet applicable requirements to accredit capacity for satisfying resource adequacy requirements, including, but not limited to, maximum number of annual emergency curtailments, maximum duration of emergency curtailments, and seasons in which emergency curtailments can occur.

Before an Emergency Curtailment, the Company will provide the lesser of (1) at least two hours advance notice or (2) the notice that as required in connection with requirements to accredit capacity for satisfying resource adequacy requirements.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

Large Power Demand Response Product C – Market Surplus Service
Contract periods of between three and six years are available, provided that Customer's Electric Service Agreement duration at time of bidding is at least as long as the Market Surplus Service contract, and provided that neither the Customer nor the Company has served an Electric Service Agreement cancelation notice. Product C includes a Demand Charge Credit as detailed in the Rate section below. The Company will facilitate identification of options for a customer's excess demand response capacity that doesn't fit into Large Power Demand Response Product A.

RATE MODIFICATIONS

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard Large Power rate schedule:

Demand Response Product A - Short-Term Emergency Capacity
Demand Charge Credit:
For each month that Short-Term Emergency Capacity is provided, the Customer shall receive a per kW Demand Charge Credit based on an annual market price representative of market conditions as determined by the Company. Such credit shall be applied to the demand charges billed under Schedule 74. Customer will be notified of the annual credit amount by the preceding November for the following Midcontinent Independent System Operator (MISO) planning year.

Demand Response Product C- Market Surplus Service
Demand Charge Credit:
For each month that Market Surplus Service is provided and Minnesota Power has identified an option for customer's excess demand response capacity that results in revenue for the Company, the Customer shall receive a per kW Demand Charge Credit. Such credit shall be determined by the company and applied to Customer's demand charges billed under Schedule 74.

DETERMINATION OF DEMAND RESPONSE BILLING DEMAND (Monthly)

Demand Response Billing Demand shall be calculated as follows:

The lesser of: (1) the Demand Response Contract Demand or (2) Customer's nominated demand under Schedule 74 plus, if applicable, Maximum Replacement Amount less Firm Service Level.

Any reduction in the Demand Response Billing Demand from the Demand Response Contract Demand will first reduce Product A and then Product C.

The Customer's monthly Schedule 74 Billing Demand shall be calculated in accordance with Schedule 74.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED CURTAILMENT

A Customer is deemed to have failed to comply with the emergency capacity requirements when Minnesota Power calls on the emergency capacity and the Customer's actual firm load, as measured by the meters installed by the Company (netted across aggregated Customer facilities, if applicable), has not decreased to the Firm Service Level or Targeted Demand Reduction Level.

In the event that the Customer fails to follow an Emergency Curtailment request by Minnesota Power and such failure results in (a) any financial penalties being imposed upon the Company, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases, the Customer shall reimburse the Company for that portion of the penalty and/or financial damages caused by their failure, within 15 days of notification by Minnesota Power. In the event that the Customer follows Emergency Curtailment conditions as specified herein, the Customer shall not be liable for any (a) penalties imposed on the Company, or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases. Penalties and charges may include, but are not limited to, penalties associated with disqualification of the emergency capacity as accredited capacity.

ADDITIONAL SERVICE CONDITIONS

1. The duration and frequency of curtailments shall be at the sole discretion of the Company and follow the product conditions as stated above.

2. The Customer must provide, at its expense, a means of curtailing its demand response load upon receiving a command or signal from the Company. The Company reserves the right to inspect and approve the installation.

3. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any curtailment of service.

4. Company intends to accredit and register the demand response MW as a capacity resource with MISO (or successor entity), in accordance with Module E Tariff and Business Practices Manual for Resource Adequacy. Customer agrees to participate fully in the registration procedure.

5. In the event of a material change in MISO's (or any successor organization) capacity accreditation authority, the party's shall in good faith determine the most appropriate substitute accrediting and rate or cost determination authority within six months of the date such a change was made. Except as mutually agreed by the party's, no changes in MISO responsibilities shall materially and adversely affect either party's rights or obligations under the Electric Service Agreement. Any changes would be subject to regulatory approval.

PILOT RIDER FOR REMOTE SERVICE RECONNECTION

APPLICATION

Applicable on a voluntary basis to customers taking service under the Residential Service Schedule 20 or 22, Dual Fuel Interruptible Electric Service Schedule 21, Controlled Access Electric Service Schedule 24, or Residential Electric Vehicle Service Schedule 28.

In order to be eligible for this Pilot Rider, Customer must have Advanced Metering Infrastructure (AMI) with remote reconnect capability, and shall have been disconnected following procedures specified in Company's Service Regulations, Section VI, page 3.4, Regulation 19.

RATE MODIFICATION

Remote Service Reconnection is available any time of the day, all year and the Fee shall be as follows:

Remote Service Reconnection Fee: Waive

SERVICE CONDITIONS

1. Customers may choose to be reconnected using remote AMI capability and shall be reconnected for the Remote Service Reconnection Fee specified above after they have met the payment requirement as stipulated in the Company's Service Regulations, Section VI, page 3.5, Regulation 20. This Remote Service Reconnection Fee replaces the Service Reconnection Fee specified in regulation 20.A.

2. Customers who are remotely reconnected will be walked through the process on the phone by a Company representative during the reconnection process to ensure that the connection has taken place and is completed safely.

3. Customers without existing AMI equipment may request participation in this Pilot Rider. The Company will install and commission the equipment at the Customer's residence prior to making the Pilot Rider available.

RIDER FOR CITY OF PEQUOT LAKES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Pequot Lakes, except bills for electric service to property owned by the City of Pequot Lakes.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Pequot Lakes Franchise Fee assessment in the amount of:

$1.00 per month for each electric residential account; and
$1.00 per month for each commercial, industrial or other electric service account.
Dual fuel meters shall constitute one meter for purposes of this franchise fee Ord.

100% of the City of Pequot Lakes Franchise Fee assessment collected will be passed along to the City of Pequot Lakes.

RIDER FOR RENEWABLE RESOURCES – SOLAR FACTOR ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79. This Rider shall be applicable to customers who are not exempt from Solar Energy Standard (SES) obligations under Minnesota Statutes, Section 216B.1691, subd. 2(f). During the 2013 Minnesota legislative session, Minnesota Statutes Section 216B.1691, the statute establishing Minnesota's Renewable Standard, was amended to include an additional SES under Minnesota Statutes Section 216B.1691, Subd. 2f. Included in Minnesota Statutes, Section 216B.1691, subd. 2f is a provision exempting retail electric sales to certain customers, namely large iron mining and paper production businesses, from the total retail electric sales calculation of a public utility. Per subdivision 2f(f), exempted customers are:

1. an iron mining extraction and processing facility, including a scram mining facility as defined in Minnesota Rules, part 6130.0100, subpart 16; or
2. a paper mill, wood products manufacturer, sawmill, or oriented strand board manufacturer.

Exempted customers cannot be charged for any costs specific to satisfying the Solar Energy Standard.

The solar capacity benefit charge associated with the Camp Ripley Solar Project is applied to exempt customers as they share in these benefits.

ADJUSTMENT

Customers' monthly bills will be adjusted in accordance with each customer's status per Minnesota Statutes, Section 216B.1691, Subd. 2f. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules.

	SES-Paying Customers	SES-Exempt Customers
Residential Customers	0.045¢ per kWh for all kWh	----
General Service Customers	0.051¢ per kWh for all kWh	0.031¢ per kWh for all kWh
Large Light & Power Customers	0.026¢ per kWh for all kWh	0.018¢ per kWh for all kWh
Large Power Customers	----	0.010¢ per kWh for all kWh
Lighting Customers	0.131¢ per kWh for all kWh	----

RIDER FOR ADVANCED METERING INFRASTRUCTURE (AMI) OPT-OUT

APPLICATION

Applicable to Customers taking service under: Residential Service Schedule 20 (General), Schedule 22 (Space Heating), and Schedule 23 (Seasonal) who do not want advanced metering infrastructure ("AMI") at their residence ("Opt-Out Customers"). All provisions of the Residential Service Schedule and the Company's Electric Service Regulations shall apply to the service under this Rider except as noted below.

DESCRIPTION

There shall be applied to an Opt-Out Customer's monthly bill a recurring monthly fee after enrollment. The applicable fee for participating in the AMI Opt-Out will be shown as a separate line item on the monthly bill as follows:

AMI Opt-Out Charge $20.00 per month

The monthly charge will be applied following the meter exchange. Where a meter exchange is not required, the charge will be applied following the AMI Opt-Out election or action by the Opt-Out Customer, as described in the Service Conditions.

SERVICE CONDITIONS

1. The Company shall have the right to refuse to provide AMI Opt-Out service in any of the following circumstances:
    a) If such a service creates a safety hazard to the Customer or their premises, the public, or the Company's personnel or facilities.
    b) If a Customer does not allow the Company's employees access to the meter at the Customer's premises.
    c) If the Customer has a history of meter tampering.

2. Opt-Out Provisions:
    a) Opt-Out Election: A Customer must affirmatively elect to opt-out of having electric consumption metered through AMI to obtain service under this Rider. Customers shall default to AMI absent such an election. Customers who do not provide reasonable access to their meter or affirmatively prevent the installation of AMI shall be deemed to have elected this Opt-Out Rider.
    b) Frequency of Election: A Customer may only enroll in this AMI Opt-Out Rider once per twelve-month period at the same residence.
    c) Opt-In Election: At any time, Opt-Out Customers may opt back into electric service with AMI.
    d) Local governments and entities such as condominiums and other multi-unit dwellings are not allowed to exercise the Opt-Out option on behalf of individually metered residents.

RIDER FOR ADVANCED METERING INFRASTRUCTURE (AMI) OPT-OUT

3. Metering Equipment: A non-communicating meter will be used to provide electric service for Customers who elect this option.

4. Customers enrolled in interruptible electric service, controlled access, time-of-day, or other service requiring AMI will be notified that the Customer must discontinue participation in the service offering in order to participate in this Opt-Out option.

5. Estimated Meter Reading: Opt-Out Customers may receive bills based on estimated meter reads if circumstances prevent reading a meter in a given month.

6. Billing: Customers will be billed for charges incurred for electric consumption under the applicable Residential Service Schedule, plus the Monthly Charge described in this AMI Opt-Out Rider.

RIDER FOR RESIDENTIAL TIME-OF-DAY SERVICE

APPLICATION

Applicable to customers taking service under Residential Service Schedule 20 (General) or Schedule 22 (Space Heating), for single-family dwellings. All provisions of the Residential Service Schedule shall apply to the Residential Time-Of-Day service under this Rider except as noted below.

Customers taking service under this Rider may not also take service under the Pilot Rider for Community Solar Garden Subscription, nor under the Rider for Parallel Generation.

RATE MODIFICATION

Customers will be billed at the Residential Service rate, plus the following Energy Charge Adjustments shall apply:

	Energy Charge Adjustment
All On-Peak kWh	4.800¢/kWh
All Off-Peak kWh	-0.293¢/kWh
All Super Off-Peak kWh	-3.416¢/kWh

SERVICE CONDITIONS

On-Peak, Off-Peak, and Super Off-Peak Period Defined: The On-Peak Periods shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Super Off-Peak Period shall be defined as 11:00 p.m. to 5 a.m. Central Prevailing Time (CPT), inclusive. The Off-Peak Periods shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

SPECIAL RULES

1. Any Customer choosing to be served on this rate tariff thereby waives all rights to any billing adjustment arising from any claim that the bill for the Customer's services would be cheaper on any alternative rate schedule for any period of time.

PRIVACY PROVISION

The Company follows its standard operational privacy guidelines and practices for all customers, including those participating under this Service Schedule. The Company complies with the State and Federal laws and regulations governing utility customer data

use such as the Federal Power Act, the Minnesota Public Utilities Act, and the Minnesota State Statutes including Chapters 47 and 248B.

The Company routinely collects data about and from its Customers through various sources as part of the normal course of providing services. Customer personal information, account and usage details, billing information, and program participation details are secured and retained in internal and online databases in accordance with the Company's standard operational guidelines which maintain administrative, technical, and physical safeguards to protect the privacy and security of the information. These safeguards include but are not limited to encryption, password protection, and secured files and buildings.

Energy Consumption Data:

Energy consumption and tariff data will be collected during the participation period. This data includes:

a. Date and hour of each day, with time zone;
b. Hourly interval meter usage data for 0-12 months prior to commencement of the Tariff (depending upon the date of meter installation relative to start of Tariff) and during the participation period;
c. Hourly weather data from the nearest weather station for 12 months prior to commencement of the Tariff and during the participation period;
d. Tariff sheet reference (i.e., which tariff sheet(s) each customer was on and the date range that the customer was on that tariff sheet for the 12 months prior to the commencement of the Tariff);
e. Start date of billing cycle;
f. Monthly electricity bill (i.e., $ amount) for 12 months prior to commencement of the Tariff; and
g. Electricity usage from the monthly bill for 12 months prior to commencement of the Tariff and during the participation period.

RIDER FOR CITY OF SANDSTONE FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Sandstone, except bills for electric service to property owned by the City of Sandstone.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Sandstone Franchise Fee assessment in the amount of:

$2.59 per month for each electric residential service agreement; and
$2.59 per month for each commercial, industrial or other electric service agreement.
Dual fuel meters shall constitute one meter for purposes of this franchise fee Ord.

100% of the City of Sandstone Franchise Fee assessment collected will be passed along to the City of Sandstone.

RIDER FOR CAPACITY REVENUE AND EXPENSE ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79.

CAPACITY REVENUE AND EXPENSE ADJUSTMENT

The Forecasted System Average Capacity Revenue and Expense Adjustment (CREA), that includes bilateral or customer capacity contracts and Planning Reserve Auction results for a period that is equal to or less than three years, for each month shall be the forecasted CREA for the current month divided by the forecasted Kilowatt-Hour Sales. The applicable Forecasted CREA shall be added to customers' monthly bill according to each customer's rate class and CREA Factor.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of revenue and expense for the twelve months ending May 31 of each year as reported in an annual compliance filing with the Minnesota Public Utilities Commission report to be filed by July 31 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs to the forecasted costs, and shall be applied to the subsequent months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under- recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each rate class shall be calculated as follows. The over- or under- recovery amount as shown in the current year annual compliance filing will be divided by the forecasted Kilowatt-Hours subject to the Capacity Revenue and Expense Adjustment for the proposed twelve-month recovery period the true-up rate will be in effect and then multiplied by the applicable CREA Factor. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each rate class that will be applied to Customers' bills in the same manner as the forecasted monthly CRE Charge.

FORECASTED SYSTEM AVERAGE CAPACITY REVENUE AND EXPENSE ADJUSTMENT

The monthly Forecasted Average Capacity Revenue and Expense Adjustment shall be the **sum** of the following:

(a) MISO Planning Reserve Auction charges net of revenues for the applicable MISO planning year ending May 31 of each year.

(b) Bilateral and customer capacity contract charges net of revenues with terms of three years or less for the applicable MISO planning year ending May 31 of each year.

RIDER FOR CAPACITY REVENUE AND EXPENSE ADJUSTMENT

The Forecasted Kilowatt-Hour Sales shall be Company's total forecasted kilowatt-hour Sales of Electricity, excluding inter-system sales related to economy energy sales and other energy sold on an economic dispatch basis, sales related to the renewable source and community solar garden programs, and solar energy production and purchases to meet the Solar Energy Standard.

CAPACITY REVENUE AND EXPENSE ADJUSTMENT (CREA) FACTORS

A separate CREA Factor shall be applied to calculate the Forecasted CREA Charge for each Rate Class. A Class Cost Factor shall be calculated for each Rate Class. For Residential Time-Of-Day (TOD) and Large Light & Power Time-Of-Use (TOU) customers a TOD or TOU Factor shall also be calculated for each TOD or TOU period. The CREA Factor is the Class Cost Factor multiplied by the corresponding TOD or TOU Factor.

Rate Class	Class Cost Factor	TOD / TOU Factor	CREA Factor
Residential	1.05841	1.00000	1.05841
Residential On-Peak	1.05841	1.17042	1.23878
Residential Off-Peak	1.05841	1.03330	1.09366
Residential Super Off-Peak	1.05841	0.75930	0.80365
General Service	1.02995	1.00000	1.02995
Large Light & Power	0.99451	1.00000	0.99451
Large Light & Power On-Peak	0.99451	1.17042	1.16399
Large Light & Power Off-Peak	0.99451	1.03330	1.02763
Large Light & Power Super Off-Peak	0.99451	0.75930	0.75513
Large Power	0.98328	1.00000	0.98328
Lighting	0.89264	1.00000	0.89264

RIDER FOR CAPACITY REVENUE AND EXPENSE ADJUSTMENT

2025 FORECASTED and TRUE-UP CREA RATE

Applicable Month	CREA Forecasted Rate (¢/kWh)	CREA True-up Rate (¢/kWh)
January 2025	-	
February 2025	-	
March 2025	0.0030	
April 2025	0.0030	
May 2025	(0.0060)	
June 2025		
July 2025		
August 2025		
September 2025		
October 2025		
November 2025		
December 2025		

A breakdown by month and Rate Class can be found on Minnesota Power's website at https://www.mnpower.com/CustomerService/YourBill

RIDER FOR VOLUNTARY RENEWABLE ENERGY LARGE CUSTOMERS

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74 or Large Light and Power Service Schedule 75; and having an approved Electric Service Agreement in which neither the Customer nor Minnesota Power has served a notice of contract cancelation; and subject to the Conditions below.

The total availability of service under this Rider is limited to 300 MW_{ac}, for qualifying customers who choose to offset a portion of their Firm Energy requirements in an existing Electric Service Agreement with dedicated renewable energy.

DEFINITIONS

Dedicated Renewable Resource: A new renewable generating resource(s) as defined under Minnesota Statues Section 216B.1691 that the Company will use to produce energy for sale to customer(s) under terms and condition of this Rider.

RATE MODIFICATIONS

The Rates (Monthly) and all adjustments included in the applicable service Schedule shall apply. Additionally, the Customer shall pay a monthly renewable energy surcharge for each kWh of renewable energy as defined in an Electric Service Agreement, and the Customer shall receive a credit for the rate-class-specific monthly Fuel and Purchased Energy Charge.

SERVICE CONDITIONS

1. A customer must execute an Electric Service Agreement which provides for dedication of renewable resource owned or procured by the Company and dedicated to a specific customer. The Electric Service Agreement must demonstrate benefits to the customer without harming the Company and non-participating customers and must include details of the Dedicated Renewable Resource to provide energy to the customer at the Renewable Resource Rate.

2. If applicable, multiple customers purchasing power from the same Dedicated Renewable Resource may not, in total, exceed 100% of the average annual output of the Dedicated Renewable Resource, as determined by the Company.

3. Energy purchased under this Rider will be considered as ‘first through the meter’ in deliveries to the customer.

RIDER FOR VOLUNTARY RENEWABLE ENERGY LARGE CUSTOMERS

4. When applicable, multiple customers purchasing power from the same Dedicated Renewable Resource will purchase and receive energy based on a pro-rata share of the energy produced:

   (Contracted kWac ÷ Total Resource kWac) x Resource kWh produced

5. A customer's pro-rata share of the energy purchased from a Dedicated Renewable Resource may not exceed 100% of the average annual usage of the customer's aggregated accounts subject to the contract as determined by the Company. Terms and conditions shall be reflected in the Electric Service Agreement and approved by the Commission.

6. The Company may require the credit of a customer to be established to the Company's satisfaction in sole judgment of the Company.

7. After the term or termination of the Electric Service Agreement the Company will be assigned and assume all responsibilities associated with the Dedicated Renewable Resource.

8. All Renewable Energy Credits ("RECs") associated with energy generated by Dedicated Renewable Resources shall be assigned to the Company on behalf of the Customer, and the Company shall retire any RECs associated with Dedicated Renewable Resource generation that are tracked in the Midwest Renewable Energy Tracking System program or any similar program established by the Commission under Minnesota Statutes Section 216B.1691, subdivision 4 on behalf of the Customer, unless the Electric Service Agreement describes an alternative treatment of RECs, and shall also be used for compliance with MN Renewable Energy Standard, Solar Energy Standard, and/or the Carbon Free standard under Minnesota Statutes Section 216B.1691, as applicable, and any other eligible state or federal requirements and standards.

9. Service may be limited at the sole discretion of the Company. The Company reserves the right to terminate this program at its sole discretion upon a requisite filing with the MPUC. The Electric Service Agreement will define the terms and conditions under which the Company may terminate the program and will include an assignment provision which allows customers who choose to terminate their participation in the program early to reassign their subscription to another customer. In addition, the Customer's Electric Service Agreement associated with this Rider will include language that protects the Company and the non-participating customers from paying for the renewable asset in the event the contract is terminated early.

DEFINITIONS OF CLASSES OF CUSTOMERS

RESIDENTIAL

A customer using electric energy supplied for residential (household) purposes.

RESIDENTIAL WITH TOTAL ELECTRIC SPACE HEATING

A subdivision of the Residential classification that includes those customers who use electricity as the source of space heating throughout the entire premises from permanently installed electric heating equipment.

COMMERCIAL

A customer using service at a location where the purchaser is engaged in selling, warehousing, or distributing a commodity, in some business activity, in rendering professional service, or in some form of social activity. In borderline cases where the nature of the customers' activities does not differentiate clearly between Commercial and Industrial, the service is classified as Commercial.

INDUSTRIAL

A customer using service at a location where the purchaser is engaged in an industrial activity, such as the operation of factories, mills, machine shops, mines, oil wells, refineries, pumping plants, cleaning and dyeing works, creameries, canning establishments, stockyards, etc., that is, in extractive, fabricating or processing activities.

GOVERNMENTAL

Municipalities and all divisions or agencies of state or federal governments.

RESIDENTIAL SERVICE RULES

1. Equipment which is capable of disturbing service to neighboring customers and/or motors operating with phase converters totaling more than 20 horsepower shall be separately metered on the applicable General Service schedule. Equipment capable of disturbing service to neighboring customers may include, but is not limited to, the following: welders, motors not conforming to Company's starting current limits, cooking and heating equipment of a design not approved by the Company.

2. In buildings having two or more apartments (as defined below), each apartment shall be considered a single-family dwelling. For each apartment building or portion of a building used for apartments that is arranged to permit the consumption of electricity by each apartment to be individually metered, Company will install meters to measure the consumption of electricity and will separately bill each individual apartment on the applicable rate schedule. However, where a landlord advises the Company that service applies to a single-metered residential apartment building, the billing shall be to the landlord and in accordance with Minn. Stat. 504B.215. The billing shall be computed as though each apartment used an equal portion of the total service and were independently billed. Service shall not be submetered or resold.

3. An apartment is defined as a portion of a building consisting of two or more rooms completely equipped for living purposes. Janitor's quarters shall be classified as an apartment.

4. A customer occupying a building or apartment for residential and commercial purposes jointly may combine his residential and commercial use on the applicable General Service schedule but not under the Residential Service schedule.

5. The public portion of apartment buildings, such as lobbies, halls, laundry rooms, boiler rooms, etc., and the power equipment, such as coal stokers, oil burners, air conditioners, elevators, etc., shall be served on the applicable General Service schedule.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

PURPOSE AND CONTENTS

These Service Regulations govern the supplying and taking of electric service. The regulations are designed to provide each Customer the greatest practicable latitude in the use of safe, reliable, and affordable service .

These Service Regulations, together with Extension Rules and Rate Schedules, are on file in the Company's various offices, and copies are obtainable by any Customer upon request by telephone, by mail, or www.mnpower.com.

Section I - Definitions
1 Customer
2 Company
3 Electric Service
4 Point of Delivery
5 Customer's Installation
6 Service Drop
7 Service Entrance Conductors
8 Month
9 Service Agreement
10 Notice
11 Meter
12 Customer Extension

Section II - Service Agreements
13 Form and Execution of Service Agreements
14 Contract Period of Service Agreements
15 Renewal and Termination of Service Agreements
16 Company's Right to Cancel Service Agreement or to Suspend Service
17 Successors and Assigns

Section III - Supplying and Taking of Service
18 Supplying of Service
19 Disconnection of Service
20 Reconnection of Service
21 Service Relock Penalty
22 Continuity of Service
23 Suspension of Service for Repairs and Changes
24 Use of Service
25 Customer's Responsibility
26 Right-of-Way
27 Access to Premises
28 Location of Point of Attachment

Section IV - Customer's Installation
29 Nature and Use of Installation
30 Inspection by Company
31 Changes in Installation

Section V - Company's Installation
32 Installation and Maintenance
33 Protection by Customer
34 Customer Extensions
35 Alteration of Facilities

Section VI - Metering
36 Installation
37 Evidence of Consumption
38 Tests

Section VII - Parallel Generation
39 Design
40 Disconnection
41 Customer Responsibility

Section VIII - Billing
42 Billing Periods

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

43 Separate Billing for Each Point of Delivery
44 Adjustment for Inaccurate Meter Registration
45 Late Payment Charge
46 Delinquent Bills
47 Unlawful Use of Service
48 Charge for Restoring Service
49 Selection of Schedule
50 Proration of Bills
51 Company Billing Errors

Section IX - Deposits and Guarantees
52 When Required
53 When Refunded
54 Interest on Deposits
55 Conditions Requiring a Deposit or Guarantee
56 Conditional Service Prior to Establishment of Credit

Section X - Cold Weather Rule
57 Applicability
58 Definitions
59 Company Obligations Before Cold Weather Period
60 Notice Before Disconnection During Cold Weather Period
61 Cold Weather Rule
62 Verification of Income
63 Prohibitions and Requirements
64 Disputes, Customer Appeals
65 Customers Above 50 Percent of State median income

Section XI – Residential Customer Protections
66 Applicability
67 Budget Billing Plans
68 Payment Agreements
69 Undercharges
70 Medically Necessary Equipment
71 Commission Authority

Section XII – Miscellaneous Regulations
72 Conflicts
73 Franchise Limitations
74 Franchise Fees Notification
75 Franchise Fees Customer Notification
76 Regulation and Jurisdiction

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

SECTION I - DEFINITIONS

The following terms when used in these Service Regulations, in Rate Schedules and in Service Agreements, shall, unless otherwise indicated, have the meanings given below:

1. **Customer:** Any individual(s), partnership, association, firm, public or private corporation or governmental agency having Company's electric service at any specified location.

2. **Company:** Minnesota Power.

3. **Electric Service:** The supplying of electric power and energy, or its availability, irrespective of whether any electric power and energy is actually used. Supplying of service by Company consists of the maintaining by it, at the point of delivery, of approximately the agreed voltage and frequency by means of facilities adequate for carrying Customer's contracted load.

4. **Point of Delivery:** The end of Company's service drop, or the point where Company's wires are joined to Customer's service entrance conductors or apparatus, unless otherwise specified in Customer's Service Agreement.

5. **Customer's Installation:** In general, all wiring, appliances and apparatus of any kind or nature on Customer's side of the point of delivery (except Company's meter installation), useful in connection with Customer's ability to take electric service.

6. **Service Drop:** The wires, owned by Company, connecting Company's distribution mains to Customer's service entrance conductors.

7. **Service Entrance Conductors:** The wires provided by the Customer extending from Customer's main line switch or center at which circuits originate, to the terminal of the Company's service drop.

8. **Month:** An interval of approximately thirty days between successive meter reading dates, except when the calendar month is specified.

9. **Service Agreement:** The agreement or contract between Company and Customer pursuant to which service is supplied and taken.

10. **Notice:** Unless otherwise specified, a written notification delivered personally or mailed by one party to the other at such other party's last known address, the period of notice being computed from the date of such personal delivery or mailing.

11. **Meter:** The meter or meters, together with auxiliary devices, if any, constituting the complete installation needed to measure and report the power and energy supplied to any Customer at a single point of delivery.

12. **Customer Extension:** Any branch from, or continuation of, an existing line to the point of delivery to Customer, including increases in capacity of any of Company's existing facilities, or the changing of any line to meet the Customer's requirements, and including all transformers, service drops and meters.

SECTION II - SERVICE AGREEMENTS

13. **Form and Execution of Service Agreements:** Each application for service normally is made on Company's standard form of application, which, when properly executed by Customer and Company, becomes binding and along with the applicable Rate Schedules, Rules and Regulations, is termed a Service Agreement. Any Service Agreement referred to herein is subject to amendment or change by Company. Any such amendment or change to a Service Agreement may be subject to acceptance or approval by any regulatory body having jurisdiction thereof and upon acceptance or approval will automatically apply to any executed Service Agreement.

    If for any reason an application is not signed by the Customer, the giving of service by the Company and the accepting of such service by all Customers receiving service shall impose the same obligation on each as if a Service Agreement had been executed.

14. **Contract Period of Service Agreements:** The contract period shall be as indicated in the applicable Rate Schedule, unless otherwise provided for in the Service Agreement.

15. **Renewal and Termination of Service Agreements:** Renewals shall be as provided for in the Service Agreement. Unless otherwise provided in the Service Agreement or Rate Schedule, Customers requesting termination of service through a physical disconnect and removal of Company owned equipment must fill out Form 6032 and give Company at least 7 days notice prior to the date termination is desired. Customer will be held responsible for all service supplied to vacated premises until such notice has been received by Company. Notification may be made by writing, e-mail through the MyAccount tool, or by visiting the Company's website at www.mnpower.com.

    When the contract period of a Service Agreement is extended, the demand previously established by Customer is considered as having been established under the extended contract period.

When a new Service Agreement is entered into, the demand previously established by Customer is considered as having been established under the contract period of the new Service Agreement except that, when the contract demand under the new Service Agreement is less than 60% of the highest actual demand established in the previous contract year, the Company will waive the above requirement.

16. **Company's Right to Cancel Service Agreement or to Suspend Service:** Company, in addition to all other legal remedies, may terminate the Service Agreement, or suspend delivery of service, for any default or breach of the Service Agreement by the Customer, but no such termination or suspension will be made by Company without five (5) days written notice, excluding Sundays and legal holidays, to Customer, stating in what particular the Service Agreement has been violated, except in cases of unlawful or unauthorized use of service by Customer, or dangerous leakage or short circuit on Customer's side of the point of delivery, or in case of utilization by Customer of service in such manner as to cause danger to persons or property. Failure of Company at any time to either suspend delivery of service or to terminate the Service Agreement, or to resort to any other legal remedy, or its adoption of either one or the other of such alternatives, shall not affect Company's right to resort to any of such remedies for the same or any future default or breach by Customer.

17. **Successors and Assigns:** Service Agreements inure to the benefit of and are binding upon the respective heirs, legal representatives, successors and assigns of the parties thereto; but no assignment by Customer shall be binding upon Company until accepted in writing by the latter.

SECTION III - SUPPLY AND TAKING OF SERVICE

18. **Supplying of Service:** Service is supplied only under and pursuant to these Service Regulations and the applicable Rate Schedule, Riders, and Regulatory Rules. Service is supplied under a given Rate Schedule only at such points of delivery as are adjacent to facilities of Company adequate and suitable, as to capacity and voltage, for the service desired.

Service will be subject to disconnection and deposit requirements as provided by rules of the Minnesota Public Utilities Commission and other applicable law, if, at the time of application for service, the Customer is indebted to the Company for service previously supplied at the same or another address.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

19. **Disconnection of Service:**

A. With Notice - Service may be disconnected with notice for any reason under Minn. Rules Part 7820.1000 or as may otherwise be provided in Company's Service Regulations, Service Schedules or Service Agreements.

B. Without Notice - Service may be disconnected without notice for any reason under Minn. Rules Part 7820.1100 or as may otherwise be provided in Company's Service Regulations, Service Schedules or Service Agreements.

20. **Reconnection of Service:** Company shall reconnect service following disconnection for non-payment:

- After all past due accounts, deposits and reconnection fees, where applicable, shall have been paid or

- Under a payment agreement for all past due accounts, deposits and reconnection fees, where applicable. Payment agreements must consider a Customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to reconnect or continue service to a Customer who has entered and is reasonably on time under an accepted payment agreement. If a Customer has a history of repeatedly breaking payment agreements (two or more times in a twelve month period), a payment agreement may not be offered to be reconnected.

A. The Service Reconnection Fee shall be as follows:

i. $20.00 between the hours of 8:00 AM and 4:30 PM Monday through Friday.

ii. $100.00 after 4:30 PM, before 8:00 AM and on Saturdays, Sundays and legal holidays.

B. Where service has been disconnected under Minn. Rules Part 7820.1100.B., a reconnection fee will not be required.

C. Following disconnection under Minn. Rules 7820.1100.A., reconnection will occur only after Company has received payment from Customer of the following:

i. Power and energy not recorded on the meter at the appropriate rate, the amount of which may be estimated by Company based on the best available data.
ii. All expenses incurred by Company due to any such unauthorized act or acts.

21. **Service Relock Penalty:**

A. Company shall assess a Service Relock Penalty of $100.00 where the Company has previously disconnected service and is required to subsequently return to relock or disconnect the service after it was connected by a Customer without Company authorization.

B. Company shall assess a penalty for all expenses incurred if additional disconnection of service is required at Customer premises.

C. In the event of any loss or damage to such property of Company or other person caused by or arising out of carelessness, neglect or misuse by Customer or other unauthorized persons, the cost of making good such loss or repairing such damage shall be paid by Customer.

22. **Continuity of Service:** Company will endeavor to provide continuous service but does not guarantee a constant supply of electric energy and shall not be liable to Customer for damages occasioned by interruption, except as provided by law. The Company shall not be liable for any loss of profits, special, or consequential damages resulting from the use of service or any interruption or disturbance of service.

In the event of power shortage any curtailment among Customers shall be made as nearly as practical pro rata without liability on the part of Company to any Customer affected.

If any part of service furnished by Company is employed for purpose of pumping water, Company assumes no obligation to maintain an adequate supply for fire protection, or any other purpose, whatsoever, and such use shall not subject Company to any liability to any party for damages to person or property due to failure of water supply resulting from an interruption or deficiency of electric service from whatsoever cause the same may arise.

23. **Suspension of Service for Repairs and Changes:** When necessary to make repairs to or changes in its lines or system, Company may, without incurring any liability therefore, suspend service for such periods as may be necessary, and in such manner as to minimize inconvenience to Customer.

24. **Use of Service:** Service is for Customer's use only. Company permits redistribution and submetering only where allowed by law. The electric service equipment and associated building wiring of buildings shall be arranged by the owner to permit individual metering of the electrical consumption of each building and occupancy unit

to comply with Minn. Stat. 504B.161 and any law amendatory thereto. If desired by the owner, the Company will install and maintain necessary individual Company meters to measure consumption and render bills on the applicable Rate Schedules to each Customer and separately occupied building and occupancy unit.

In no case may Customer, except with the written consent of Company, extend or connect an installation to lines across or under a street, alley, lane, court or avenue or other public or private space in order to obtain service for adjacent property through one meter even though such adjacent property be owned by Customer. Such consent may be given when such adjacent properties are operated as one integral unit under the same name and for carrying on parts of the same business. In case of unauthorized remetering, sale or extension of service to another person, Company, after five (5) days written notice excluding Sundays and legal holidays, may discontinue the supplying of service to Customer until such unauthorized act is discontinued and full payment is made for all service supplied or used, billed on proper classification and Rate Schedule, and reimbursement in full made to Company for all extra expenses incurred, including expenses for clerical work, testing and inspections.

25. **Customer's Responsibility:** Customer assumes all responsibility on Customer's side of the point of delivery for the service supplied or taken, as well as for the electrical installation, appliances and apparatus used in connection therewith, and shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from such service or the use thereof on Customer's side of the point of delivery.

26. **Right-of-Way:** Customer shall, without compensation, make or procure satisfactory conveyance to Company of right-of-way for Company's lines necessary and incidental to the furnishing of service to Customer and for continuing or extending said lines over, under, across or through the property owned or controlled by Customer in a manner deemed appropriate by the Company (including facility maintenance and vegetation management rights).

27. **Access to Premises:** Company personnel may enter Customer's premises only as authorized by applicable law and regulations. Failure of Customer to provide Company reasonable access may result in disconnection of service under Minn. Rules Part 7820.1000(E).

28. **Location of Point of Attachment:** Customer's Point of Attachment is to be located at a point readily accessible to Company's distribution mains. Customer shall install and maintain a point of attachment for Company's service drop. Said point of attachment shall be of sufficient mechanical strength to support the wind and ice

loaded weight of the service drop and shall be located as determined by the Company.

SECTION IV - CUSTOMER'S INSTALLATION

29. **Nature and Use of Installation:** All of Customer's wires, apparatus and equipment shall be selected with the view to obtaining safety, good efficiency, good voltage regulation and the highest practicable power factor and shall be installed in accordance with standard practices. Customer shall install and maintain, on Customer's side of point of delivery, suitable protective equipment as may be required by the Company for the protection of its service to other customers and may not employ or utilize any equipment, appliance or device so as to affect adversely Company's service to Customer or to others. The Company's failure to require such equipment shall not operate to relieve Customer from the obligation to utilize and comply with standard practices. Company may require auto starters or other suitable starting devices for motors above 5 horsepower. When polyphase service is supplied by Company, Customer shall control the use thereof so that the load at the point of delivery will be maintained in reasonable electrical balance between the phases.

    Installations of neon, fluorescent, mercury vapor lamps or tubes, or other types of gaseous tube lamps, or other devices having low power factor characteristics, should be equipped with corrective apparatus to increase the power factor of each unit or separately controlled group of units to not less than approximately 90% lagging.

30. **Inspection by Company:** Company retains the right, but does not assume the duty, to inspect Customer's installation at any time and will refuse to commence or to continue service whenever it does not consider such installation to be in good operating condition, but Company does not in any event assume any responsibility whatever in connection with such matters.

31. **Changes in Installations:** As Company's service drops, transformers, meters, and other facilities used in supplying service to Customer have a definite limited capacity, Customer shall give notice to Company, and obtain Company's consent, before making any material changes or increases in Customer's installation. Company as promptly as possible after receipt of such notice will give its approval to the proposed change or increase, or will advise Customer upon what conditions service can be supplied for such change or increase. Failure to secure Company's approval shall make Customer liable for any damage to Company's facilities.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

SECTION V - COMPANY'S INSTALLATION

32. **Installation and Maintenance:** Except as otherwise provided in these Service Regulations, in Service Agreements or Rate Schedules, Company will install and maintain its lines and equipment on its side of the point of delivery, but shall not be required to install or maintain any lines or equipment, except meters, on Customer's side of the point of delivery. Only Company's agents are authorized to connect Company's service drop to Customer's service entrance conductors and to connect Company's meters.

    A. Electrical Permit: The Company is prohibited from connecting its service drop to Customer's service entrance conductors until permitted by the governmental authority having jurisdiction.

    B. Standard Connection: The ordinary method of connection between Company's distribution mains and Customer's service entrance conductors will be by overhead wires. If Customer desires to have connection made in any other manner, special arrangements will be made between Customer and Company by which the connection will be made and maintained at Customer's expense.

    C. Suitable Space: The Customer shall provide at no cost to Company a suitable room or space for Company's transformers and equipment specifically used in providing service to Customer when such room or space is deemed necessary by Company.

33. **Protection by Customer:** Customer shall protect Company's wiring and apparatus on Customer's premises and shall permit no one except Company's agents or persons authorized by law to inspect or handle same. In the event of any loss or damage to such property of Company or other person caused by or arising out of carelessness, neglect or misuse by Customer or other unauthorized persons, the cost of making good such loss or repairing such damage shall be paid by Customer.

    Company shall not be responsible to Customer or any other party because of any damage resulting from such installations which are not readily subject to inspection from the ground and the exterior of the premises, or from the meter location, unless Customer shall have notified Company of a condition which, in the reasonable opinion of the Customer, requires attention and the Company shall have had a reasonable time within which to inspect and, if necessary, repair the same.

34. **Customer Extensions:** The Company, at its own expense, makes extensions where the revenue therefrom is sufficient, in Company's opinion, to justify the necessary expenditure.

Where the Company cannot be assured that the business offered is of sufficient duration, where unusual expenditures are necessary to supply service because of location, size or character of installation, or where area requirements of regulatory bodies may control, the Customer or Customers shall make arrangements satisfactory to Company dependent upon the particular conditions of each situation.

35. **Alteration of Facilities:** Company will, at its discretion, alter, relocate, convert to underground, or remove Company's facilities as may be requested in writing by Customer. Customer shall pay Company for all costs, except as limited below, associated with such alteration, relocation, conversion to underground, or removal including any new facilities required to provide service after the alteration, relocation, conversion, or removal.

    Customers requesting the alteration, relocation, conversion, or removal shall pay the estimated cost for the change, less salvage, of the facilities required to effect such change prior to Company committing funds for the work. Where the actual cost is different from the estimated cost upon which the advance payment was based, as determined upon completion of the requested alteration, relocation, conversion, or removal, Company will refund any excess payment made by Customer or render a bill for any additional amount due.

SECTION VI - METERING

36. **Installation:** Company shall furnish and install the necessary meter or meters, and Customer shall provide and maintain a location, free of expense and satisfactory to Company, all in accordance with Company's Metering Standards.

37. **Evidence of Consumption:** Unless proven to be inaccurate, the registration of Company's meter shall be accepted and received at all times and places as prima facie evidence of the amount of power and energy taken by Customer.

38. **Tests:** Company tests its meters and maintains their accuracy of registration in accordance with good practice. On request of Customer, Company will make a special test which will be done at the expense of the Company. If the Customer requests another test before the expiration of a twelve-month period, the Customer shall bear the cost of the test if the meter is found to be in error by less than 2%, fast or slow. The average registration accuracy of a meter is taken as the mean of full load (100% of rated load) accuracy, and light load (5-10% of rated load) accuracy. At Company's discretion, tests may be made under average load conditions.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

SECTION VII - PARALLEL GENERATION

39. **Design:** Customer's electric generating equipment shall be designed (1) to operate in synchronization with Company's system and (2) to automatically disconnect the facility from Company's system in the event Company's system becomes de-energized unless by mutual agreement between the Customer and Company. All synchronizing and protective devices to accomplish this mode of operation shall be provided and maintained by Customer.

40. **Disconnection:** Customer shall provide and maintain a manual, lockable disconnect switch providing a visible open and capable of isolating the Customer's generator from the Company's electrical system. This disconnect switch shall be readily accessible to Company personnel at all times, shall include a provision for padlocking it in the open position, and shall meet all other reasonable requirements established by Company.

41. **Customer Responsibility:** Customer shall pay for the cost of rebuilding and/or modifying Company facilities to provide adequate capacity for the parallel generation system and adequate protection for the Company's electrical system.

    Customer shall be subject to the State of Minnesota Distributed Energy Resources Interconnection Process and Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements or the most recent version of Minnesota's interconnection standards. Copies of such standards shall be made available to Customer upon request and are available at www.mnpower.com.

SECTION VIII - BILLING

42. **Billing Periods:** Bills ordinarily are rendered regularly at monthly intervals, but may be rendered more or less frequently at Company's option. Non-receipt of bills by Customer does not release or diminish the obligation of Customer with respect to payment thereof.

43. **Separate Billing for Each Point of Delivery:** At each point of delivery the use of service is metered separately for each Customer served. Whenever for any reason Company furnishes two or more meter installations for a single Customer, or supplies service under a Rate Schedule which does not require a meter, each point of metering and/or point of delivery where no meter is required is considered as a separate service. A separate Service Agreement is required, and bills are separately calculated, for each such separate service, except where Company may, under special circumstances, waive this requirement.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

44. **Adjustment for Inaccurate Meter Registration:** Meter too fast or too slow: In the event that any routine or special test of a Company meter discloses its average accuracy of registration to be in error by more than 2%, fast or slow, Company will refund the overcharge for a fast meter or charge for electricity consumed, but not included in the bills previously rendered for a slow meter. The refund or charge for both fast and slow meters will be based on corrected meter readings for a period equal to one-half the time elapsed since the last previous test but not to exceed six (6) months, unless it can be established that the error was due to some cause, the date of which can be fixed with reasonable certainty, in which case the refund or charge will be computed to that date, but in no event for a period longer than one (1) year.

    Whenever any bill or bills have been adjusted or corrected as provided above, the Company will refund to existing Customer any amount due when the amount due exceeds one ($1.00) dollar or to previous Customer any amount due when the amount due exceeds two ($2.00) dollars or Company will bill Customer for any amount owed when the amount owed exceeds ten ($10.00) dollars, as the case may be.

    Meter fails to register or registers intermittently: When the average error cannot be determined by test because the meter is not found to register or is found to register intermittently, the Company may charge for an estimated amount of electricity used, which shall be calculated by averaging the amounts registered over corresponding periods in previous years or in the absence of such information, over similar periods of known accurate measurement preceding or subsequent thereto, but in no event shall such charge be for a period longer than one year.

    If a Customer has called to the Company's attention doubts as to the meter's accuracy and the Company has failed within a reasonable time to check it, there shall be no back billing for the period between the date of the Customer's notification and the date the meter was checked.

45. **Late Payment Charge:** Company shall assess a Late Payment Charge of 1.5% per monthly billing period, on that portion of a retail Customer's account representing charges for Company service(s) past due, if the unpaid balance exceeds $10.00. All late payments received will be credited against the oldest outstanding account balance before the application of any Late Payment Charge. The unpaid Company account balance for a Customer under the Budget Billing Plan or another Company approved payment plan shall mean that the Company budget arrears balance and not the accumulated actual Company balance will be subject to a Late Payment Charge. No Late Payment Charge will be charged on the portion of the Company balance in dispute while dispute procedures are underway. A Late Payment Charge may be retroactively charged on the settled amount after dispute procedures are

completed. At Company's discretion, any Late Payment Charge, or portion thereof, may be waived provided such waiver is consistent with the Minnesota Public Utilities Act.

A. Residential Customer: A Late Payment Charge shall be added to any Company account for which payment is not received and credited by Company within fifteen (15) days from the current billing date, plus ten (10) days of grace period, or a total of twenty-five (25) days. Residential customer who qualifies for assistance under the Low Income Home Energy Assistance Program (LIHEAP) may request waiver of the Late Payment Charge on the "current bill" portion of each monthly bill. Self-qualification using LIHEAP income guidelines will be permitted for Senior Citizens at age 62 or older. Efforts will be made by Company to work with local governmental agencies to pre-qualify Customers where administratively feasible. Customer accounts must be re-qualified annually.

B. Nonresidential Customer: A Late Payment Charge shall be added to any Nonresidential Customer account for which bill payment is not received and credited by Company within fifteen (15) days from the current billing date.

46. **Delinquent Bills:** Bills become delinquent if not paid on or before the past due date as shown on bill and service may be discontinued upon five (5) days written notice, excluding Sundays and legal holidays, to Customer after becoming delinquent. During the Cold Weather Rule months, October 1 through April 30, service may be disconnected only as provided in section 60 and Minnesota Statutes, section 216B.096. For residential customers, such written notice of disconnection shall specify a disconnection date not earlier than the third working day after the next scheduled billing date.

47. **Unlawful Use of Service:** In any case of tampering with meter installation or interfering with the proper functioning thereof or any other unlawful use or diversion of service by any person, or evidence of any such tampering, interfering, unlawful use or service diversion, Customer is liable to immediate discontinuance of service, without notice, and to prosecution under applicable laws, and Company shall be entitled to collect from Customer at the appropriate rate for all power and energy not recorded on the meter by reason of such tampering, interfering, or other unlawful use or service diversion (the amount of which may be estimated by Company from the best available data), and also for all expenses incurred by the Company on account of such unauthorized act or acts.

48. **Charge for Restoring Service:** If service to Customer is discontinued by Company for valid cause, then before service is restored, Customer shall pay Company all permitted costs of discontinuing and restoring service. There will be no charge for reconnection when service has been discontinued in the event of a condition

determined to be hazardous to Customer, to other Customers of Company, to Company's equipment, or to the public.

If Customer requests that service be discontinued and subsequently requests restoration of service at same premises within twelve (12) months of discontinuance, the charge for restoring service will be the sum of minimum bills during the elapsed period but not less than all costs of discontinuing and restoring service.

49. **Selection of Schedule:** The Company's Rate Schedules are designed for service supplied to Customer on a continuous annual basis. Customer may elect to take service under any of the Rate Schedules applicable to such service. Company will advise Customer of the Rate Schedules which, in its judgment, are best adapted to Customer's needs on an annual basis, but such advice must be based upon Customer's statements as to Customer's installation and requirements for service and Company assumes no responsibility for the selection of the Rate Schedule made by Customer. If Customer changes selection of a Rate Schedule, Customer may not go back to the previous Rate Schedule for a period of twelve (12) months; provided, however, that a Large Light and Power Customer whose normal monthly firm demand is below 50,000 kW shall be billed on the Large Power Service Schedule in months in which its measured demand, as adjusted for power factor, exceeds 50,000 kW, and shall go back to the Large Light and Power Service Schedule when its demand falls below 50,000 kW. Rules applicable to specific Rate Schedules shall apply when Customer desires service on other than a continuous annual basis, or the term of service provision of the Rate Schedule is greater than one (1) year.

If, for any cause a Service Agreement is entered into in which is specified a Rate Schedule not applicable to the class of service taken, on discovery of the error all bills rendered during the preceding twelve (12) months will be recalculated in accordance with the properly applicable Rate Schedule and Company will refund to existing Customer any amount due, when the amount due exceeds one ($1.00) dollar or to previous Customer any amount due, when the amount due exceeds two ($2.00) dollars, or Company will bill Customer for any amount owed, when the amount owed exceeds ten ($10.00) dollars, as the case may be. If the amount due Company is not paid within ten (10) days from presentation of bill, or Customer does not agree to payment over a reasonable period of time, or Customer fails to sign a new Service Agreement, Company may, after five (5) days written notice excluding Sundays and legal holidays, disconnect service.

50. **Proration of Bills:** Bills for energy used during a billing period that is longer or shorter than the normal billing period by more than five (5) days shall be prorated on a daily basis, but no billing will be made for three (3) or less days when no energy is used. However, in no event will the total length of service between initial and final

service be taken as less than one (1) month. No bill will be prorated for change in operating level within the billing period.

51. **Company Billing Errors:** When a Customer has been overcharged or undercharged as a result of incorrect reading of the meter, incorrect application of rate schedule, incorrect connection of the meter, application of an incorrect multiplier or constant or other similar reasons, the amount of the overcharge shall be refunded to the Customer or the amount of the undercharge may be billed to the Customer as detailed in Minnesota Administrative Rules 7820.3800 subparts 2 through 4.

    A. Remedy for Overcharge: If a Customer was overcharged, the Company shall calculate the difference between the amount collected for service rendered and the amount the Company should have collected for service rendered, plus interest up to a maximum of three years from the date of discovery. Interest will be calculated as prescribed by Minnesota Statutes, section 325E.02(b). If the recalculated amount indicates that more than $1.00 is due an existing Customer or $2.00 is due a person no longer a Customer of the Company, the full amount of the calculated difference between the amount paid and the recalculated amount shall be refunded to the Customer.

    B. Remedy for Undercharge: If a Customer was undercharged, the Company shall calculate the difference between the amount collected for service rendered and the amount the Company should have collected for service rendered, for the period beginning one year before the date of discovery. If the recalculated amount due the Company exceeds $10.00, the Company may bill the Customer for the amount due. The Company must not bill any undercharge incurred after the date of a Customer inquiry or complaint if the Company failed to begin investigating the matter within a reasonable time and the inquiry or complaint ultimately resulted in the discovery of the undercharge.

    C. Exception if Error Date Known: If the date the error occurred can be fixed with reasonable certainty, the remedy shall be calculated on the basis of payments for service rendered after that date, but in no event for a period beginning more than three years before the discovery of an overcharge or one year before the discovery of an undercharge.

SECTION IX - DEPOSITS AND GUARANTEES

52. **When Required:** Company may require Customer to make a deposit or guarantee satisfactory to Company to secure the payment of bills as they become due. Specific conditions requiring deposits or guarantees are identified in Regulation 54. The amount of such deposit shall not exceed twice the average monthly bill of Customer

as estimated by Company from Customer's statement in his or her application or as thereafter ascertained.

53. **When Refunded:** The deposit shall be refunded to Customer after twelve (12) consecutive months of prompt payment of all Company bills. Company may, at its option, refund the deposit by direct payment or as a credit on the bill. Upon termination of service, the deposit with accrued interest shall be credited to Customer's final bill and the balance, if any, shall be returned within forty-five (45) days to Customer with a written receipt as required under Minn. Stat. 325E.02(b).

54. **Interest on Deposits:** Interest shall be paid annually on all deposits at the rate specified by Minn. Stat. 325E.02(b) or other applicable laws of the State of Minnesota and will be applied against the electric service bill. Any unpaid interest at time of final settlement of Customer's accounts will be credited to Customer's accounts.

55. **Conditions Requiring a Deposit or Guarantee:** Company may require a deposit or guarantee of payment as condition of obtaining new service or continuing existing service under Minn. Rules Part 7820.4300, 7820.4400 or as may otherwise be provided below.

    A. Customer has outstanding a prior utility service account with another electric or gas utility which at the time of request for service remains unpaid and not in dispute.

    B. Information requested under Minn. Rules Part 7820.4300 or 7820.4400 is not provided within twenty (20) days of the request for service (except where Customer has sought but not yet received credit information from a prior utility).

    C. Information provided pursuant to Minn. Rules Part 7820.4300 or 7820.4400 is determined to be false or erroneous.

56. **Conditional Service Prior to Establishment of Credit:** Conditional service shall be provided expeditiously upon receipt of an application for service, and for up to twenty (20) days until credit has been satisfactorily established. Conditional service may be disconnected immediately without notice if required information or a required deposit or guarantee has not been received twenty (20) days after Company's request.

SECTION X – COLD WEATHER RULE

57. **Applicability:** This section applies only to residential customers of the Company.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

58. **Definitions:**

A. The terms used in this section have the meanings given them in Minnesota Statute, 216B.096.

B. “Cold weather period” means the period from October 1 through April 30 of the following year.

C. “Customer” means a residential customer of the Company.

D. “Disconnection” means the involuntary loss of Company heating service as a result of a physical act by the Company to discontinue service. Disconnection includes installation of a service or load limiter or any device that limits or interrupts Company service in any way.

E. “Household income” means the combined income, as defined in Minnesota Statutes 290A.03, subdivision 3, of all residents of the Customer’s household, computed on an annual basis. Household income does not include any amount received for energy assistance.

F. “Reasonably timely payment” means payment within five working days of agreed-upon due dates.

G. “Reconnection” means the restoration of Company heating service after it has been disconnected.

H. “Summary of rights and responsibilities” means a Commission-approved notice that contains, at a minimum, the following:

i. an explanation of the provisions of subdivision 5;

ii. an explanation of no-cost and low-cost methods to reduce the consumption of energy;

iii. a third-party notice;

iv. ways to avoid disconnection;

v. information regarding payment agreements;

vi. an explanation of the Customer’s right to appeal a determination of income by the Company and the right to appeal if the Company and the Customer cannot arrive at a mutually acceptable payment agreement, and a list of

names and telephone numbers for county and local energy assistance, and weatherization providers in each county served by the Company.

I. "Third-party notice" means a commission-approved notice containing, at a minimum, the following information;

i. a statement that the Company will send a copy of any future notice of proposed disconnection of Company heating service to a third party designated by the residential customer;

ii. instructions on how to request this service; and

iii. a statement that the residential customer should contact the person the Customer intends to designate as the third-party's name.

J. "Company" means Minnesota Power.

K. "Company heating service" means natural gas or electricity used as a primary heating source, including electricity service necessary to operate gas heating equipment, for the Customer's primary residence.

L. "Working days" means Mondays through Fridays, excluding legal holidays. The day of receipt of a personally served notice and the day of mailing a notice shall not be counted in calculating working days.

59. **Company Obligations Before Cold Weather Period:** Each year, between August 15 and October 1, the Company must provide all Customers, personally or by first class mail, a summary of rights and responsibilities. The summary must also be provided to all new residential customers when service is initiated.

60. **Notice Before Disconnection During Cold Weather Period:** Before disconnecting Company heating service during the cold weather period, the Company must provide, personally or by first class mail, a commission-approved notice to a Customer, in easy-to-understand language, that contains, at a minimum, the date of the scheduled disconnection, the amount due, and a summary of right and responsibilities.

61. **Cold Weather Rule:**

A. During the cold weather period, the Company may not disconnect and must reconnect Company heating service of a Customer whose household income is at or below 50 percent of the state median income if the Customer enters into and makes reasonably timely payments under a mutually acceptable payment

agreement with the Company that is based on the financial resources and circumstances of the household; provided that, the Company may not require a Customer to pay more than ten percent of the household income toward current and past Company bills for Company heating service.

B. The Company may accept more than ten percent of the household income as the payment arrangement amount if agreed to by the Customer.

C. The Customer or a designated third party may request a modification of the terms of a payment agreement previously entered into if the Customer's financial circumstances have changed or the Customer is unable to make reasonably timely payments.

D. The payment agreement terminates at the expiration of the cold weather period unless a longer period is mutually agreed to by the Customer and the Company.

E. The Company shall use reasonable efforts to restore service within 24 hours of an accepted payment agreement, taking into consideration Customer availability.

62. **Verification of Income:**

A. In verifying a Customer's household income, the Company may:

1. accept the signed statement of a Customer that the Customer is income eligible;

2. obtain income verification from a local energy assistance provider or a government agency;

3. consider one or more of the following:

i. the most recent income tax return filed by members of the Customer's household;

ii. for each employed member of the Customer's household, paycheck stubs for the last two months or a written statement from the employer reporting wages earned during the preceding two months;

iii. documentation that the Customer receives a pension from the Department of Human Services, the Social Security Administration, the Veteran's Administration, or other pension

provider; a letter showing the Customer's dismissal from a job or other documentation of unemployment; or

iv. other documentation that supports the Customer's declaration of income eligibility.

B. A Customer who receives energy assistance benefits under any federal, state or county government programs in which eligibility is defined as household income at or below 50 percent of state median income is deemed to be automatically eligible for protection under this section and no other verification of income may be required.

63. **Prohibitions and Requirements:**

A. Section 63 applies during the cold weather period.

B. The Company may not charge a deposit or delinquency charge to a Customer who entered into a payment agreement or a Customer who has appealed to the Commission under Minnesota Statutes 216B.096 subdivision 8.

C. The Company may not disconnect service during the following periods:

i. during the pendency of any appeal under Minnesota Statutes 216B.096 subdivision 8;

ii. earlier than ten working days after the Company has deposited in first class mail, or seven working days after the Company has personally served, the notice required under Minnesota Statutes 216B.096 subdivision 4 to a Customer in an occupied dwelling;

iii. earlier than ten working days after the Company has deposited in first class mail the notice required under Minnesota Statutes 216B.096 subdivision 4 to the recorded billing address of the Customer, if the Company has reasonably determined from an on-site inspection that the dwelling is unoccupied;

iv. on a Friday, unless the Company makes personal contact with and offers a payment agreement consistent with this section to the Customer;

v. on a Saturday, Sunday, holiday , or the day before the holiday;

vi. when Company offices are closed;

vii. when no Company personnel are available to resolve disputes, enter into payment agreements, accept payments, and reconnect service, or;

viii. when Commission offices are closed.

D. The Company may not discontinue service until the Company investigates whether the dwelling is actually occupied. At a minimum, the investigation must include one visit by the Company to the dwelling during normal working hours. If no contact is made and there is reason to believe that the dwelling is occupied, the Company must attempt a second contact during non-business hours. If personal contact is made, the Company representative must provide notice required under Minnesota Statutes 216B.096 subdivision 4 and, if the Company representative is not authorized to enter into a payment agreement, the telephone number the Customer can call to establish a payment agreement.

E. The Company must reconnect Company service if, following disconnection, the dwelling is found to be occupied and the Customer agrees to enter into a payment agreement or appeals to the Commission because the Customer and the Company are unable to agree on a payment agreement.

64. **Disputes, Customer Appeals:**

A. The Company must provide the Customer and any designated third party with a Commission-approved written notice of the right to appeal:

i. the Company determination that the Customer's household income is more than 50 percent of state median household income; or

ii. when the Company and Customer are unable to agree on the establishment or modification of a payment agreement.

B. A Customer's appeal must be filed with the Commission no later seven working days after the Customer's receipt of a personally served appeal notice, or within ten working days after the Company has deposited a first class mail appeal notice.

C. The Commission must determine all Customer appeals on an informal basis, within 20 working days of receipt of a Customer's written appeal. In making its determination, the Commission must consider one or more of the factors in Minnesota Statutes 216B.096 subdivision 6.

D. Notwithstanding any other law, following an appeals decision adverse to the Customer, the Company may not disconnect Company heating service for seven

working days after the Company has personally served a disconnection notice, or for ten working days after the Company has deposited a first class mail notice. The notice must contain, in easy-to-understand language, the date on or after which disconnection will occur, the reason for disconnection, and ways to avoid disconnection.

65. **Customers Above 50 Percent of State Median Income:** During the cold weather period, a Customer whose household income is above 50 percent of state median income:

    A. has the right to a payment agreement that takes into consideration the Customer's financial circumstances and any other extenuating circumstances of the household; and

    B. may not be disconnected and must be reconnected if the Customer makes timely payments under a payment agreement accepted by the Company.

SECTION XI – RESIDENTIAL CUSTOMER PROTECTIONS

66. **Applicability:** The provisions of this section apply to residential customers of the Company.

67. **Budget Billing Plans:** The Company shall offer a Customer a budget billing plan for payment of charges for service, including adequate notice to Customer prior to changing budget payment amounts.

68. **Payment Agreements:** In compliance with Minnesota Statute 216B.098, the Company shall offer a payment agreement for the payment of arrears for past due customers that have not yet been disconnected, or to customers disconnected during non-Cold Weather Rule months. During Cold Weather Rule months, Cold Weather Rule provisions will apply. Payment agreements must consider a Customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to reconnect or continue service to a Customer who has entered and is reasonably on time under an accepted payment agreement. If a Customer has a broken payment agreement immediately preceding disconnection or has a history of repeatedly breaking payment agreements (two or more times in a twelve month period), a payment agreement may not be offered to be reconnected. Under these circumstances, to be reconnected, all past due accounts, deposits and reconnection fees, where applicable, shall have been paid.

69. **Undercharges:**

A. In compliance with Minnesota Statutes 216B.098, the Company shall offer a payment agreement to Customers who have been undercharged if no culpable conduct by the Customer or resident of the Customer's household caused the undercharge. The agreement must cover a period equal to the time over which the undercharge occurred or a different time period that is mutually agreeable to the Customer and the Company, except that the duration of a payment agreement offered by the Company to a Customer whose household income is at or below 50 percent of state median household income must consider the financial circumstances of the Customer's household.

B. No interest or delinquency fee may be charged as part of an undercharge agreement under this subdivision.

C. If a Customer inquiry or complaint results in the Company's discovery of the undercharge, the Company may bill for the undercharges incurred after the date of the inquiry or complaint only if the Company began investigating the inquiry or complaint within a reasonable time after it was made.

70. **Medically Necessary Equipment:** The Company shall reconnect or continue service to a Customer's residence where a medical emergency exists or where medical equipment requiring electricity necessary to sustain life is in use, provided that the Company receives from a medical doctor written certification, or initial certification by telephone and written certification within five business days, that failure to reconnect or continue service will impair or threaten the health or safety of a resident of the Customer's household. The Customer must enter into a payment agreement.

71. **Commission Authority:** In addition to any other authority, the Commission has the authority to resolve Customer complaints against the Company, whether or not the complaint involves a violation of this Chapter 216B of Minnesota Statutes. The Commission may delegate this authority to Commission staff as it deems appropriate.

SECTION XII - MISCELLANEOUS REGULATIONS

72. **Conflicts:** In case of conflict between any provision of these approved Service Regulations, Customer's Service Agreement or a Rate Schedule, the provision of the Service Agreement takes precedence, followed by the provision of the Rate Schedule. The Customer's Service Agreement will identify all such conflicts with the Service Regulations or Rate Schedule.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

73. **Franchise Limitations:** All Service Agreements are subject to existing franchise limitations.

74. **Franchise Fees Notification:** The Company will notify the Minnesota Public Utilities Commission of any new, renewed, expired, or changed fee, authorized by Minn. Stat. § 216B.36 to raise revenue, at least 60 days prior to its implementation. If the Company receives less than 60 days' notice of a repealed or reduced fee from a city, the Company will notify the Minnesota Public Utilities Commission within 10 business days of receiving notice. Notification to the Minnesota Public Utilities Commission will include a copy of the relevant franchise fee ordinance, or other operative document authorizing imposition of, or change in, the fee.

75. **Franchise Fees Customer Notification:** The following language will be included with the first customer bills on which a new or amended franchise fee is collected:

    The City of _____granted Minnesota Power a franchise to operate within the City limits. An electric franchise fee of (____% OF GROSS REVENUES or $_____ PER METER or $_____ PER KWH) will be imposed on customers effective MM/DD/YYYY. The line item appears on your bills as "_____Franchise Fee." Minnesota Power remits 100% of this fee to the City of _____.

76. **Regulation and Jurisdiction:** Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable Rate Schedule or other superseding Rate Schedules in effect from time to time. All the rates and regulations referred to herein are subject to amendment and change by Company. Any such amendments or changes may be subject to acceptance or approval by any regulatory body having jurisdiction thereof.

EXTENSION RULES

I. GENERAL

The following rules shall govern the extension of Company's electric transmission/distribution lines and service connections in all areas served by Company to all classes of retail Customers requiring Company's standard single or three phase electric transmission/distribution service.

The standard type of extension shall be the most feasible and economical as determined by the Company and shall be constructed in accordance with Company's Distribution Construction Standards. When conditions require extensions from or connections to lines of voltages other than the standard voltage or where line construction other than Company's standard construction is required, Company reserves the right to make adjustments to these rules for such non-standard extensions such that adequate revenues are provided to fund the extension cost for a single point of delivery. The Company's standard extension does not include a second service point.

Except when meter pedestals for underground service have been installed, all facilities installed by Company on either side of the service point and not expressly sold and conveyed to Customers by written agreement shall at all times remain the sole property of Company, regardless of any Contributions in Aid of Construction paid by Customers. When meter pedestals have been installed by Company, Customer shall be responsible for installing and will remain the sole property owner of all facilities on Customer's side of the meter. In case of cancellation of Customer's service agreement for any cause, Company shall have the right to remove all facilities installed for serving Customer.

Service will be supplied in accordance with Company's schedules for the respective classes of service in the respective rate areas, Company's Electric Service Regulations and the provisions of these Extension Rules.

II. EXTENSION COST

The "Extension Cost" is the estimated cost of extending lines and the addition or relocation of facilities to serve new Customers or new loads. This shall be the total cost of extending the line, including all branch or lateral lines, but excluding the cost of transformer, meter and any system betterments. The Extension Cost shall include the customer's choice of either an overhead or underground service point and estimation of special condition costs anticipated.

III. EXTENSION COST CALCULATION

The Extension Cost shall be calculated by Company as follows:

1. All single phase line extensions of 1,000 feet or less shall be calculated using a unit cost of $37.00 per foot. The unit cost of $37.00 per foot may be adjusted for non-standard extensions or special conditions.

2. All single phase line extensions over 1,000 feet and all three phase line extensions shall be estimated based on Company's Compatible Unit Estimator (CUE). The CUE consists of Compatible Units Identifications (CU IDs), which contain descriptions and costs of service-extension components such as distribution materials, labor, and vehicle usage. The service-extension designer chooses the necessary CU IDs needed for the line extension. A total job cost is estimated using the CUE based on data for the applicable CU IDs. The distribution material cost is the actual cost of items listed in the Company's inventory data base, based on actual purchase prices. The labor cost is based on one lead lineman and two linemen, the typical crew used to install a new service extension. The vehicle use cost is based on a percentage of labor based on prior year actual labor overheads.

IV. CONTRIBUTIONS

The "Contribution in Aid of Construction," hereafter referred to as Contribution, is the amount required to support the Company's Extension Cost excluding allowance if applicable and including any applicable fees. Where a line extension other than Company's standard type extension is requested by the customer, a Contribution shall be required to support all additional costs of such non-standard extension. A customer may request an upgrade to existing service or an additional service point. An advanced Contribution is required to support costs of all additional facilities requested by the customer.

Any customer may pay all or part of a Contribution required of another Customer with such other Customer's authorization, and subject to acceptance by Company.

V. BASIS FOR MAKING EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS ARE $30,000 OR LESS

If the Company's standard type construction is used in making the extension, Customer shall not be required to make payment to Company for the Extension Cost if:

The Extension Cost is for a Residential customer and does not exceed $751 for single-phase;

The Extension Cost is for a General Service or Commercial Electric Vehicle Charging Service customer and does not exceed $1,020 for single-phase and $3,152 for three-phase; or

EXTENSION RULES

The Extension Cost is for a Large Light and Power customer and does not exceed $30,000.

If the extension cost exceeds the respective rate class service-extension allowance specified above and is for single phase service, customer must pay the Company in advance a Contribution for the Extension Cost in excess of the respective rate class service-extension allowance.

If the Extension Cost exceeds the respective rate class service-extension allowance specified above and is for three phase non-refundable line extension service, Customer has the following options:

1. Pay Company in advance a Contribution for the Extension Cost in excess of the rate class service-extension allowance, or

2. No advance contribution for extension costs will be required, if the customer enters into a five year Electric Service Agreement where the Company's costs relating to the entire extension are equal to or less than three times the Customer's Guaranteed Annual Revenues (GAR), as defined below, or

3. If the Customer enters into a five-year Electric Service Agreement where the Company's costs relating to the entire extension are greater than three times the Customer's guaranteed annual revenues, the Customer will be required to pay the Company in advance a Contribution for the balance of the Extension Cost not supported by GAR.

The Guaranteed Annual Revenue (GAR) is the minimum annual amount of revenue from billings under the applicable rate schedule that a Customer who enters into an Electric Service Agreement (ESA) commits to pay to Minnesota Power to support extension costs for installing a three phase line extension.

To determine the required GAR, the Company estimates the costs of the service extension from which the revenue is derived. The service-extension job is estimated using the Compatible Unit Estimator (CUE). The cost estimate is divided by three according to the three-times-annual-revenue methodology. This is the annual amount the Customer will pay under the GAR agreement.

The GAR used in the ESA shall be estimated by the Company and determined under the existing rate schedule for providing service to the Customer.

Developers of Residential Housing Sites

A Developer of residential housing sites requiring electric service must make a Contribution equal to the Extension Cost. As customers are connected Developer is entitled to receive a refund for each customer connected of the current residential allowance amount. However, in no event will the total refund exceed the Contribution. After Developer has received the maximum allowable refund or after the initial five years, whichever occurs first, customers requesting service to additional lots for which the extension was made shall make appropriate arrangements directly with Company in order to satisfy additional extension costs related to the respective service connections.

VI. BASIS FOR MAKING EXTENSIONS FOR TEMPORARY SERVICE

"Temporary Service," for purposes of these Extension Rules, is service to a Customer whose use of that service, in the Company's judgment, may be of less than five years duration, or is service to a Customer who is unwilling to enter into an Electric Service Agreement having a minimum term of five years.

Customers expected to take service for less than one year duration shall be required to take such service in accordance with Company's Temporary Service Rider to the applicable General Service Schedules.

Customers expected to take Temporary Service for more than one year but less than five years will be served under the Company's standard rate schedules. Such customers with requirements of 500 kW or more shall enter into a contract for a minimum term of one year.

Prior to installation Temporary Service Customers shall pay a Contribution equal to the estimated cost of installation and removal of the facilities required to render Temporary Service.
A connection to a permanent service for power used during construction is not considered to be Temporary Service under these rules.

VII. REAPPORTIONMENT AND REFUNDS

When the Extension Cost is $30,000 or less and additional Customer(s) are connected to a line extension during the initial five year period of any Customer on the extension, the Extension Cost(s) of all previously connected Customer(s) on the extension will be reapportioned among all Customers served from the combined line extension, including the Customer(s) who are being added to the extension. The reapportionment shall be calculated such that each individual customer on the line extension shall be responsible for:

EXTENSION RULES

1. The cost of that portion of the extension which services only that individual Customer; plus

2. The cost of that portion of the line extension which that individual Customer shares with other Customers on the line extension divided by the total number of Customers who share such portion of the line extension.

After reapportionment it will be determined whether the previously connected Customer(s) are entitled to a refund. If a refund is due, the amount to be refunded shall be the difference between the previous and reapportioned Extension Costs, provided that such refunds will not:

1. Exceed the actual Contribution paid by the respective Customer.

2. Be made to any Customer after the expiration of the initial five year period of that Customer.

3. Be made after Customer terminates service.

When a Customer who has paid a Contribution terminates service within the initial five year period and another Customer immediately commences taking service at the same premises, such Customer may transfer his right to future refunds, if any, to the new Customer, provided an agreement covering such transfer is executed by the Customers and accepted by the Company at the time the new Customer applies for service.

Following the initial five year period of the most recently connected Customer(s) on the extension, any line extension necessary to serve additional Customers will be considered as a separate extension not affecting Customers connected previously.

When the Extension Cost is $30,000 or less and the Customer has entered into an Electric Service Agreement and paid a Contribution, the Company will, through its Customer Information System, at the end of the each year of the Electric Service Agreement, compare the Customer's average annual revenue for the first year and thereafter, to the minimum annual revenue which Customer elected to guarantee. The Company will, at the election of the Customer:

1. Collect an additional contribution from the Customer not to exceed an amount equal to the difference between the extension cost supported by the revenue for the first year and the extension cost supported by the minimum annual revenue the Customer elected to guarantee; or

2. Continue the minimum guaranteed annual revenues set forth in the existing Electric Service Agreement.

In no event will the minimum annual guarantee be greater than the amount necessary to satisfy the Extension Cost.

VIII. SPECIAL CONDITIONS

Construction of an extension will commence when the following conditions have been met.

1. Agreements, when required, shall have been executed by each Customer and accepted by Company specifying initial contract period, guaranteed annual revenue, and any Contribution.

2. Each Customer has paid to Company his share of any Contribution.

3. Satisfactory right-of-way necessary for the construction, operation and maintenance of the extension (including any vegetation management rights) both for the purpose of providing access to the extension on Customers' premises and for continuing the extension to other Customers, has been furnished without expense to the Company.

4. Each Customer has made satisfactory credit arrangements with the Company. In the case of tenants, the Company may require owner to guarantee payment.

5. The extension cost will include excess installation costs incurred by the Company because of special conditions that impede the installation of distribution facilities. Such special conditions include, but are not limited to ground frost, surface or subsurface impediments and submarine installations. Surface or subsurface impediments may include, but are not limited to: rock, bedrock, subsurface structures and wetlands.

6. Winter charges will be assessed October 15 through April 1 of each year. In no event will Customer costs exceed line extension costs.

IX. BASIS FOR MAKING DISTRIBUTION EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS EXCEED $30,000

The above rules shall be applicable except where specifically stated otherwise and except that the Extension Cost will be the actual cost determined upon completion of the extension. The amount of Extension Costs relating to the extension which will be recovered by the Company through application of its rate schedule will be determined on an individual customer basis. Electric Service Agreements will be required and will be for

sufficient duration and at sufficient revenue levels to support extension and other costs required to provide service.

If the Extension Cost exceeds the Extension Cost Credit as determined by the Company, the Customer(s) shall pay the Company a Contribution equal to the amount of the Extension Cost that exceeds the Extension Cost Credit. Where more than one Customer is served from the extension, the Contribution will be apportioned in the ratio of each Customer's Contract Demand to total Contract Demand for all Customers initially served from the extension. If there are circumstances unique to an extension in which application of the above rules would not be appropriate or would not properly recover costs, the Company will make necessary adjustments in the application of the rules such that adequate revenues are provided to fund Extension Costs through a combination of Extension Cost Credits and/or Contributions. Similarly, any refund which may be due, as a result of increased Customer Contract Demand during the initial ten year period, or as a result of additional Customers being served subsequently but during the initial ten year period, will be determined by the Company based upon all relevant dates such that revenue recovery is adequate to fund the Extension Costs through a combination of Extension Cost Credits and/or Contributions.

X. BASIS FOR MAKING TRANSMISSION EXTENSIONS FOR PERMANENT SERVICE

"Transmission" service for purposes of these Extension Rules is service to a Customer taken at 115 kV or higher. Customer connections involving loads served at transmission voltage will be considered on an individual customer basis. Electric Service Agreements will be required and will be of sufficient duration and at sufficient revenue levels to support extension and other costs required to provide service.

REQUEST FOR BUDGET BILLING PLAN FORM

Any all-year retail customer may apply for service to be billed in accordance with Company's Budget Billing Plan by completing the applicable form available at:

http://www.mnpower.com/CustomerService/BudgetBilling

Billing under this plan shall commence upon acceptance of the application by Company. Company may require partial payment of arrears for those customers who wish to include a large arrears balance in a newly established budget billing plan.

The amount of the monthly budget billings shall be determined as follows:

1. Where sufficient billing history is available,

   A. Company will determine Customer's average monthly billing during the preceding 12 months

   B The average monthly billing determined in Step A shall be adjusted for anticipated changes in rate level during the following 12 months.

   C. An existing arrears or credit balance shall be divided by twelve and added to or deducted from the amount determined in Step B.

   D. The amount of the monthly budget billing shall then be the amount determined in Step C rounded to the nearest dollar.

2. Where insufficient billing history is available, Company will determine Customer's connected load for use in estimating the first year's consumption upon which to base budget billings.

Customer's budget billings shall be reviewed and recalculated annually on the date following preparation of the twelfth billing under an existing budget billing plan. Company may also review Customer's account at times other than the normal review date and, where an unusually large arrears or credit balance exists, adjust the budget billing amount accordingly. Customer shall be notified of such adjustment made in the budget billing amount. When there is an unusually large credit balance, Customer may request a refund and/or reduction of budget billings.

Customer may discontinue budget billing at any time by notifying Company. Company may discontinue budget billing upon failure of the Customer to make timely payments of budget billings. Any credit balance remaining at the time of discontinuance in the Plan shall be carried forward unless Customer requests a refund. Any amount past due shall be treated under Company's normal notice and collection procedures.

STANDARD CONTRACTS AND AGREEMENTS

The application for Residential electric service can be found at:
https://www.mnpower.com/CustomerService/ResidentialConstruction

The application for Commercial electric service can be found at:
https://www.mnpower.com/CustomerService/CommercialConstruction

Sample Electric Service Agreement Form:

Form 351 Rev. 1/00

ELECTRIC SERVICE AGREEMENT

THIS AGREEMENT, made this _____ day of _____ , _____, between Minnesota Power, a Minnesota corporation, and _____, hereafter called Customer, in consideration for the covenants and promises made herein creates the obligation of Minnesota Power to furnish electric service and Customer to pay for said electric service in accordance with the following terms and conditions.

1. Electric service shall be furnished to Customer's premises located at _____
_____
in the County of _____ and State of Minnesota, described as follows:

2. Electric service shall be furnished at a point of delivery described as _____
_____

3. Annual revenues paid to Minnesota Power by Customer inclusive of payments for electric service received, billed at the applicable rate schedule plus any adjustments shall not be less than _____ per year, for a period of not less than _____ years, commencing from the date Minnesota Power begins providing electric service or 90 days from the date of installation of said electric service, whichever occurs first. An annual billing will be rendered for any deficit to the above annual revenue guarantee.

4. An advance payment of _____ shall be made to cover that portion of Minnesota Power's investment not covered by the revenue guarantee.

5. This electric service shall be billed at the current applicable rate and class at the time the electric service is used or as approved by any regulating body having jurisdiction thereof.

6. Meter-Special Conditions: _____
_____
_____

7. The parties hereto mutually agree to abide by any and all applicable statutes, agency rules and Minnesota Power's Electric Service Regulations which are hereby incorporated by reference.

8. This Agreement is not assignable to any other party without the express written consent of Minnesota Power.

9. This Agreement shall be in full force and effect for the term above specified and each party shall be bound unless an express written release is executed by the party not requesting said release.

MINNESOTA POWER

By _____
Title _____

CUSTOMER

_____
By _____
Title _____

RESERVED FOR FUTURE USE

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

TERRITORY

Applicable to Community-Based Energy Development (C-BED) projects located in the State of Minnesota.

APPLICATION

To any qualifying owner of a C-BED project who meets Company's Electric Service Regulations and any applicable Riders, technical standards and rules. Service under this Schedule is closed to new customers.

A C-BED project must be a new renewable energy project that utilizes an eligible energy technology, as defined in Minn. Stat. § 216B.1691, subd. 1(a). A C-BED project may either be a stand-alone project or part of a community energy partnership that allows Company participation as an owner, equity partner, or provider of technical or financial assistance:

(1) has no single qualifying owner owning more than 15 percent of a C-BED wind energy project unless: (i) the C-BED wind energy project consists of only one or two turbines; or (ii) the qualifying owner is a public entity listed under Minn. Stat. § 216B.1612, subd. 2(c)(5), that is not a municipal utility;
(2) demonstrates that at least 51 percent of the gross revenues from a power purchase agreement over the life of the C-BED project will flow to qualifying owners and other local entities;
(3) includes a qualifying owner, or any combination of qualifying owners, that may develop a joint venture project with a nonqualifying renewable energy project developer. However, the terms of this Schedule may only apply to the portion of the energy production of the total project that is directly proportional to the equity share of the C-BED project owned by the qualifying owners; and
(4) has a resolution of support adopted by the county board of each county in which the C-BED project is to be located, or in the case of a C-BED project located within the boundaries of a reservation, the tribal council for that reservation;

Where a qualifying owner means:

(1) a Minnesota resident;
(2) a limited liability company that is organized under Minn. Stat. Chapter 322B and that is made up of members who are Minnesota residents;
(3) a Minnesota nonprofit organization organized under Minn. Stat. Chapter 317A;
(4) a Minnesota cooperative association organized under Minn. Stat. Chapter 308A or 308B, including a rural electric cooperative association or a generation and transmission cooperative on behalf of and at the request of a member distribution utility;
(5) a Minnesota political subdivision or local government including, but not limited to, a municipal electric utility, or a municipal power agency on behalf of and at the request of a member distribution utility, a county, statutory or home rule charter city, town,

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

school district, or public or private higher education institution or any other local or regional governmental organization such as a board, commission, or association; or

(6) a tribal council.

TYPE OF SERVICE

Output of the C-BED project shall be provided at 60 hertz and at the voltage and phase relationship as agreed to by Company and a qualifying owner.

RATE

A qualifying owner may sell all the energy produced by the C-BED project to Company or use a portion of the energy from the C-BED project and sell the remaining to Company. The following information provides guidelines for the negotiated power purchase agreements for service under this C-BED Schedule.

Company may purchase all or a portion of the energy made available by the qualifying owner from the C-BED project. A qualifying owner and Company shall negotiate the rate and power purchase agreement terms consistent with this Schedule. In the alternative, at the discretion of a qualifying owner, the qualifying owner and Company may negotiate a power purchase agreement with terms different from this Schedule. Company must receive Minnesota Public Utilities Commission approval of a power purchase agreement for a C-BED project. Nothing in this Schedule shall be construed to obligate Company to enter into a power purchase agreement.

The energy rate shall equal the net present value of the nominal payments to the C-BED project divided by the total expected energy production of the C-BED project over the 20-year life of the power purchase agreement with a rate higher in the first ten years of the power purchase agreement than in the last ten years. The receipt of the payment of this rate constitutes a transfer of the property rights of all renewable and other attributes/credits associated with the generation from the C-BED project to Company, unless otherwise agreed to by the qualifying owners of the C-BED project and Company.

Qualifying and nonqualifying owners shall provide sufficient security as determined by Company based on standard industry practice, risk-adjusted for the C-BED project, that considers such things as ownership arrangement, project accreditation, credit rating and experience of financing sources and project management and project development experience to secure performance under the power purchase agreement, and shall not transfer the C-BED project to a nonqualifying owner during the initial 20 years of the power purchase agreement.

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

A C-BED project that is operating under a power purchase agreement under this Schedule is not eligible for net energy billing under Minn. Stat. § 216B.164, subd. 3, or for production incentives under Minn. Stat. § 216C.41.

SERVICE CONDITIONS

1. A C-BED project must be: (1) safely integrated into and operated within Company's grid without causing any adverse or unsafe consequences; and (2) consistent with Company's resource needs as identified in Company's most recent resource plan submitted under Minn. Stat. § 216B.2422 and meet Company's cost and reliability requirements to fulfill some or all of the identified need at a minimal impact to customer rates.

2. All electricity delivered to Company by a qualifying owner shall be measured by one or more meters installed at a single point of common coupling or as determined by Company. The meter(s) for C-BED service shall measure the flow of capacity and energy from a qualifying owner to Company only. Any flow of capacity and energy from Company to a qualifying owner shall be separately metered.

3. Service shall be provided under this Schedule if Company has sufficient capacity available in existing transmission and distribution facilities to provide such service at the location where service is requested.

4. A qualifying owner shall pay Company the installed cost of any additional required facilities, including any required studies and testing which, at a minimum, demonstrate upfront the C-BED project's technical feasibility and resource adequacy.

5. Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Schedule.

RATE, SERVICE, PROCESS AND TECHNICAL DOCUMENTS AVAILABILITY

Related Company rate, service, process and technical documents for distributed generation are available by contacting Company at 218-722-2625.

SOLARSENSE CUSTOMER SOLAR PROGRAM

APPLICATION

The goal of the Low Income ("LI") Solar Grant Program is to increase the accessibility of solar energy to Customers by creating a viable, long-term solar market for low-income customers in northern Minnesota. Starting in 2021, the annual budget is $120,000 per year, with a maximum individual grant cap of $30,000. This allows for up to four projects per year to be funded at the $30,000 level. A Low Income Solar Grant Committee ("Committee") comprised of both external stakeholders and Minnesota Power employees make project funding recommendations.

GRANT COMMITTEE CONFLICTS OF INTEREST

In order to evaluate possible conflicts, all Low Income Solar Grant Committee candidates must complete a Conflict of Interest disclosure. If it is determined the candidate has a conflict of interest, or the appearance of a conflict of interest, they will not be eligible to join the Committee. The following Conflict of Interest Policy applies to all Grant Committee members.

Existence of Conflict of Interest or Appearance of Conflict of Interest

A conflict of interest exists if a Committee member:

1. Is an applicant for a Low Income Solar Grant, intends to apply for a grant (as an individual or with an organization) in the next two years, or is personally involved as a partner to the project, or
2. Serves on the Board of Directors or other governing or advisory board of an applicant organization, or
3. Is a volunteer or paid employee of an organization being considered for funding, or
4. Is a paid consultant or service provider of an organization being considered for funding, or
5. Has an immediate family member or relation with an applicant that would impair their ability to make a grants award decision.

Minnesota Power also reserves the right to determine when a Grant Committee member's relationship with an individual or organization creates an appearance of a conflict of interest that, in its judgment, could compromise the integrity of the grant process and should be treated as a conflict of interest.

Remedies for Conflicts of Interest

If a Committee member has a conflict of interest as defined above, they must notify Minnesota Power as soon as they are aware of a conflict. Committee members with a conflict of interest have one of two options to remedy the conflict 1) recuse themselves from the entire grant process for that cycle (including the meeting, discussion, and voting) or 2) resign from the committee. Committee members will only be allowed to recuse themselves

SOLARSENSE CUSTOMER SOLAR PROGRAM

from one grant cycle. If conflicts persist, the member will no longer be eligible to serve on the Grants Committee.

If Minnesota Power or the committee member identifies a perceived conflict of interest, the Company will make a determination on how to proceed. Possibilities include, but are not limited to:

- Allowing the committee member to remain on the committee and review applications without limitation
- Having the committee member recuse themselves from reviewing the application(s) where a perceived conflict of interest exists but allowing them to review all others
- Recusing the committee member from the entire grant process for that grant cycle.

PILOT FOR RETAIL COMPANY-OWNED ELECTRIC VEHICLE CHARGING SERVICE

APPLICATION

Available to all customers taking service at Company owned Electric Vehicle Service Equipment (EVSE) charging stations. Service shall be delivered at publicly available charging stations operated by the Company. Stations may include Direct Current Fast Charging (DCFC) and Level 2 EVSE infrastructure served by Company owned facilities.

TYPE OF EQUIPMENT

For purposes of this tariff, Electric Vehicle Service Equipment means the installed device used to deliver electricity for electric vehicle charging and includes the ungrounded, grounded, and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets or apparatuses associated with the installed devices.

PAYMENT COLLECTION METHODS

All Electric Vehicle Service Equipment will have a minimum of two payment options for taking service at Company owned EVSE charging stations.

RATES

Connection Fees:

Level 2 Charger Only:	$3.00
DCFC 100 kW or less:	$5.00
DCFC 101-200 kW:	$6.00
DCFC 200 kW plus:	$7.00

Charge per kWh:	Level 2	DCFC
On-peak (kWh)	31.896¢	45.930¢
Off-peak (kWh)	22.832¢	32.878¢
Super Off-Peak (kWh)	16.183¢	23.304¢

PILOT FOR RETAIL COMPANY-OWNED ELECTRIC VEHICLE CHARGING SERVICE

EVSE TIME OF DAY PERIODS

On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. CST Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. CST Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak.

Weekdays	Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Legend	Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
-1 Super off-peak	Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
0 Off-peak	Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
1 Peak	Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1

Weekends & Holidays	Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Legend	Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
-1 Super off-peak	Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
0 Off-peak	Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
1 Peak	Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

Contact Theodore Widmer
Title: Account Analyst II
Phone: (218) 355-3197 FAX: Email: twidmer@allete.com

REPORT FOR: ALLETE, Inc. 12647
REPORTING PERIOD: 2024

Supervisor Josh Rostollan
Title: Supervisor
Phone: (218) 355-3151 FAX: Email: jrostollan@allete.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	ALLETE, Inc.	**Submission Status/Date:**	Submitted	04/30/2025
2	Current Address of Principal Business Office	30 West Superior Street Duluth MN 55802 0000			
3	Preparer's Legal Name Operator (if different than line 1)				
4	Current Address of Preparer's Office (if different than line 2)				
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility	☐ State ☐ Municipal ☒ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Community Choice Aggregator	☐ Transmission ☐ Behind the Meter ☐ Wholesale Power Marketer ☐ DSM Administrator	

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Stephen Scott Phone: (202) 586-5140 Email: stephen.scott@eia.gov

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 2. PART A. GENERAL INFORMATION

LINE NO.						
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT)	[ ] NPCC	[ ] SPP		
		[ ] FRCC	[ ] RFC (formerly ECAR, MAIN. MAAC)	[ ] WECC		
		[x] MRO	[ ] SERC			
2	Name of RTO or ISO	[ ] California ISO	[ ] Southwest Power Pool			
		[ ] Electric Reliability Council of Texas	[X] Midwest ISO			
		[ ] PJM Interconnection	[ ] ISO New England			
		[ ] New York ISO	[ ] None			
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO				
4	Did Your Company Operate Generating Plants(s)?	[x] Yes	[ ] No			
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant	[ ] Buying distribution on other electrical system			
		[x] Transmission	[x] Wholesale power marketing			
		[x] Buying transmission services on other electrical system	[ ] Retail power marketing			
		[x] Distribution using owned/leased electric wires	[ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))			
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts)	1,532.0	Prior Year	1,551.0	
		Winter (Megawatts)	1,532.0	Prior Year	1,528.0	
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[x] Yes	[ ] No			
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes	[ ] No			
	If "Yes", Please Provide Additional Contact Information	Name: Andy Scheidel				
		Title: Fleet Administrator				
		Telephone: 218 - 355 - 2753	Fax: - -	Email: ascheidel@mnpower.com		

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	5,832,104	11	Sales to Ultimate Consumers	8,391,265
2	Purchases from Electricity Suppliers	7,147,244	12	Sales For Resale	4,182,855
3	Exchanged Received (In)		13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	16,352
5	Exchanged Net				
6	Wheeled Received (In)	2,647,577			
7	Wheeled Delivered (Out)	2,567,216	15	Total Energy Losses (positive number)	469,237
8	Wheeled Net	80,361			
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	13,059,709	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	13,059,709

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 2. PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	884,002.2
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	249,963.6
4	Electric Credits/Other Adjustments	$	-22,045.6
5	Revenue from Transmission	$	74,495.4
6	Other Electric Operating Revenue	$	15,864.0
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	1,202,279.6

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **MN**

1	Total Number of Distribution Circuits	340.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	1.0

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. [x] Yes [ ] No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. [x] Yes [ ] No

	State	MN
3a.	SAIDI value including Major Event days	119.900
3b.	SAIDI value excluding Major Event days	119.900
4	SAIDI value including Major Event days minus loss of supply	109.430
5a.	SAIFI value including Major Event days	1.300
5b.	SAIFI value excluding Major Event days	1.300
6.	SAIFI value including Major Event days minus loss of supply	1.110
7.	Total number of customers used in these calculations	138,546.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)	69.0
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[ ] Yes [x] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	

13. Do you include inactive accounts? ☐ Yes ☐ No

14. How do you define momentary interruptions ☐ Less than 1 min. ☐ Less than 5 min. ☐ Other

15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? kv

16. Is information about customer outages recorded automatically? ☐ Yes ☐ No

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State MN **Balancing Authority**	56669				
Revenue (thousand dollars)	154,078.7	174,471.2	555,452.3	0.0	884,002.2
Megawatthours	983,680	1,204,294	6,203,291	0	8,391,265
Number of Customers	125,896	26,027	419	0	152,342
Are your rates decoupled?	Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	[N] automatic	[N] automatic	[N] automatic	[N] automatic	
	[N] proceeding	[N] proceeding	[N] proceeding	[N] proceeding	
Cents/Kwh	15.663	14.487	8.954		10.535
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Are your rates decoupled?					
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?					
Cents/Kwh					
Total					
Revenue (thousand dollars)	154,078.7	174,471.2	555,452.3	0.0	884,002.2
Megawatthours	983,680	1,204,294	6,203,291	0	8,391,265
Number of Customers	125,896	26,027	419	0	152,342

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 4. PART B. SALES TO ULTIMATE CUSTOMERS. ENERGY – ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 4. PART C. SALES TO ULTIMATE CUSTOMERS. DELIVERY – ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total
Revenue (thousand dollars)
Megawatthours
Number of Customers

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 4. PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

REPORT FOR: ALLETE, Inc. 12647

REPORTING PERIOD ENDING: 2024

SCHEDULE 5. MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory **MN** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	11,828.397	57,972.080			69,800.477
2	Peak Demand Savings (MW)	1.412	4.004			5.416
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	141089.292	794,654.670			935,743.962
4	Peake Demand Savings (MW)	0.924	2.692			3.616
	Reporting Year Incremental Costs					
5	Customer Incentives	1,710.748	2,847.528			4,558.276
6	All other costs	2,220.539	941.877			3,162.416
	Incremental Life Sycle Costs					
7	Customer Incentives	1,710.748	2,847.528			4,558.276
8	All other costs	2,220.539	941.877			3,162.416
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	11.928	13.708			26.000

Please provide website address to your energy efficiency program reports:

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

DMS Administration only. List all utilities that you provide service for.

State	Utility Name

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory MN Balancing Authority 56669

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	7,084	473	6		7,563
2	Energy Savings (Mwh)	61.210	55.990	0.540		117.740
3	Potential Peak Demand Savings (MW)	19.146	2.987	303.031		325.164
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

5	Customer Incentives	1,842.697	597.102	11,496.440		13,936.239
6	All other costs					

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory MN **Balancing Authority** 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	15,596				15,596

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **MN** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	56	1	0	0	57
2	Number of AMI Meters	125,840	26,026	419	0	152,285
3	Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4	Number of non AMR/AMI Meters	0	0	0	0	0
5	Total Number of Meters (All Types), line 1+2+4	125,896	26,027	419	0	152,342
6	Energy Served Through AMI	983,242	1,204,248	6,203,291	0	8,390,781
7	Number of Customers able to access daily energy usage through a webportal or other electronic means	125,896	26,027	419	0	152,342
8	Number of customers with direct load control					

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State	MN Balancing Authority 56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photo voltaic	Net Metering Installed Capacity (MW)	9.589	8.987	0.020	0.000	18.596
	Net Metering Installations	1,014	191	1	0	1,206
	Virtual NM Installed Capacity (1 MW and greater)					0.000
	Virtual NM Customers (1 MW and greater)					0
	Virtual NM Installed Capacity (less than 1MW)	0.518	0.522	0.000	0.000	1.040
	Virtual NM Customers (less than 1MW)	95	3	0	0	98
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	3,422.875	1,025.631	0.000	0.000	4,448.506
Battery Storage	PV-Paired Net Metering Installed Capacity (MW)	0.554	0.006	0.000	0.000	0.560
	PV-Paired Energy Capacity (MWh)					0.000
	PV-Paired Installations	30.000	1.000	0.000	0.000	31.000
	Not PV-Paired Net Metering Installed Capacity (MW)					0.000
	Not PV-Paired Energy Capacity (MWh)					0.000
	Not PV-Paired Net Metering Installations					0.000
	Total Battery Storage Capacity	0.554	0.006	0.000	0.000	0.560
	Total Battery Storage Energy Capacity (MWh)	0.000	0.000	0.000	0.000	0.000
	Total Battery Storage Installations	30	1	0	0	31
Wind	Installed Net Metering Capacity (MW)	0.072	0.093	0.000	0.000	0.165
	Number of Net Metering Customers	7	7	0	0	14
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0.000
Other	Installed Net Metering Capacity (MW)					0.000
	Number of Net Metering Customers					0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0.000

SCHEDULE 7. PART A. NET METERING Continued

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Total	Installed Net Metering Capacity (MW)	10.179	9.602	0.020	0.000	19.801
	Number of Net Metering Customers	1116	201	1	0	1318
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	3,422.875	1,025.631	0.000	0.000	4,448.506
Grand Total All States	**Net Metering Installed Capacity (MW)**	10.179	9.602	0.020	0.000	19.801
	Net Metering Installations/customers	1116	201	1	0	1318
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	3,422.875	1,025.631	0.000	0.000	4,448.506

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR ALLETE, Inc.

REPORT PERIOD ENDING:

SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS

If your company owns and/or operates a distribution system, please report information on known distributed generation (grid connected/synchronized) capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State	Balancing Authority	< 1MW

1. Number of generators
2. Total combined capacity (MW)
3. Capacity that consists of backup-only units
4. Capacity owned by respondent

Capacity by Technology and Sector (MW)

	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
5. Internal combustion						
6. Combustion turbine(s)						
7. Steam turbine(s)						
8. Fuel Cell(s)						
9. Hydroelectric						
10. Photovoltaic						
10a. Nature of PV Data:						
11. Battery Capacity (MW)						
11a. *Energy Capacity(MWh)						
12. Wind turbine(s)						
13. Other						
14. Total						

*Line 11a Energy Capacity is not included in the toal on line 14.

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN - Aitkin				
2	MN - Benton				
3	MN - Carlton				
4	MN - Cass				
5	MN - Cook				
6	MN - Crow Wing				
7	MN - Hubbard				
8	MN - Itasca				
9	MN - Koochiching				
10	MN - Lake				
11	MN - Morrison				
12	MN - Otter Tail				
13	MN - Pine				
14	MN - St Louis				
15	MN - Stearns				
16	MN - Todd				
17	MN - Wadena				

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 9. COMMENTS

SCHEDULE	PART	LINE NO.	COLUMN	NOTES
(a)	(b)	(c)	(d)	(e)

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

EIA861 ERROR LOG

Part	State	BA ID	Error No.	Error Description/Override Comment	Type	Override

APPENDIX L

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

MINNESOTA POWER'S CONSERVATION FILINGS

APPENDIX L
DEMAND-SIDE MANAGEMENT AND CONSERVATION

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. Applicants requested and were granted an exemption to this rule requirement by the Minnesota Public Utilities Commission. In lieu of the information required by Minn. R. 7849.0290, Applicants agreed to provide a summary of the conservation and demand-side management information that was provided as part of Applicants' individual Integrated Resource Plan and Conservation and Improvement Plan ("CIP") filings. The Applicants also agreed to provide information regarding how conservation and energy efficiency was considered by Midcontinent Independent System Operator, Inc. ("MISO") in its evaluation of the Project. A summary of this information is provided in this appendix and discussed in Section 3.6 of the Application.

Minnesota Power

Minnesota Power filed its 2024 Energy Conservation and Optimization Plan with the Commission on April 1, 2025 in Docket No. E015/M-25-48. A copy of the "Summary" section and the "Status Report" section of this filing is provided in this appendix. Minnesota Power filed its 2025 Integrated Resource Plan ("IRP") ("2025 IRP") with the Commission on March 3, 2025 in Docket No. E015/RP-25-127. Appendix B of the 2025 IRP filing contained information regarding Minnesota Power's planning and strategies for demand-side management, Energy Efficiency, and CIP. A copy of Appendix B of the 2025 IRP filing is provided in this appendix. Additional information regarding Minnesota Power's conservation and demand-side management programs can be found on Minnesota Power's website at: https://www.mnpower.com/ProgramsRebates.

MISO Energy Efficiency Considerations

MISO's annual transmission planning process develops multiple future scenarios to study transmission needs under a variety of economic, policy, and technological possibilities. Each future scenario contains assumptions about future fuel costs, environmental regulations, demand and energy levels, and technological possibilities.

As part of the development of these future scenarios, MISO develops forecasts for conservation, energy efficiency, and demand response, collectively referred to as "Distributed Energy Resources" ("DER") by MISO. These forecasts are developed by aggregating each MISO member's load forecasts. To consider a broader range of potential DER outcomes, MISO creates forecasts considering varying adoption rates, technological advancements, and economic factors. MISO's forecasts are developed for each of MISO's 10 Local Resource Zones, to consider regional differences, and then are aggregated to a MISO-wide forecast.

For the Series 1 futures developed to support Tranche 1, MISO commissioned Applied Energy Group ("AEG") to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities ("LSE") and secondary research.

To support Series 1A modeling used to support Tranche 2.1, AEG compiled DER programs by type and cost into program blocks for Electric Generation Expansion Analysis System ("EGEAS") – an integrated resource planning tool – through study period ending in 2042.

According to AEG data, Future 1 DER program levels represent minimum expected resource levels. Therefore, Future 1A programs are included as minima within the base model of all Series 1A scenarios. Futures 2A and 3A employ all Future 1A program amounts and allow incremental program blocks (the difference of total Future 2A or Future 3A programs and Future 1A levels) for selection. Previously referred to as demand-side additions or management ("DSM"), these resources were modeled as program blocks in three main categories: Demand Response ("DR"), Energy Efficiency ("EE"), and Distributed Generation ("DG"). Programs also fall into two sectors: Residential and Commercial and Industrial ("C&I").

During the program selection phase for the Future 2A and 3A models, incremental program blocks were offered against supply-side alternatives to determine economic viability. For both Future 2A and 3A, EGEAS selected the following program blocks: C&I Price Response, Residential Direct Load Control, and Residential Price Response. Future 2A also selected C&I Demand Response. Additionally, Future 3A selected C&I Utility Incentive PV; C&I High-, Mid-, and Low-Cost Energy Efficiency; and Residential High- and Low-Cost Energy Efficiency. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of the DER programs considered by MISO in MTEP24 is provided below in Table 1.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals in Table 2 below. Table 2 and Table 3 show total DER technical potential and additions modeled in MISO by the end of the study period.

Table 1 MTEP24 Distributed Energy Resource Programs[1]

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 2 DER Capacity (GW): 20-Year Technical Potential Additions in MISO in Series 1A Futures[2]

Series 1A DERs Capacity (GW) Technical Potential & Added	Future 1A	Future 2A		Future 3A	
	Added	Potential	Added	Potential	Added
Demand Response (DR)	10.8	11.2	11.2	11.2	11
Energy Efficiency (EE)	17.7	19.4	17.7	20.5	20.5
Distributed Generation (DG)	19.9	19.9	19.9	28.6	20.5

[1] *Available at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf*
[2] *Id*.

Table 3 DER Energy (GWh): 20-Year Technical Potential Additions in MISO in Series 1A Futures[3]

Series 1A DERs Energy (GWh) Technical Potential & Added	Future 1A	Future 2A		Future 3A	
	Added	Potential	Added	Potential	Added
Demand Response (DR)	1,051	1,147	1,147	1,154	1,142
Energy Efficiency (EE)	75,620	80,247	75,620	78,763	78,763
Distributed Generation (DG)	34,977	34,977	34,977	48,173	35,993

[3] *Id*.

2024 CONSOLIDATED FILING

ENERGY CONSERVATION AND OPTIMIZATION PLAN











minnesota power

AN ALLETE COMPANY

April 1, 2025

Docket Nos. E-015/M-25-48, E-015/CIP-23-93, E,G-999/CI-22-624

ISA Combined Application
Docket Nos. E015/CN-25-111 and E015/TL-25-112
Appendix 1039 | 3.18.25
Page 7 of 40

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

April 1, 2025

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Deputy Commissioner Pete Wyckoff
Minnesota Department of Commerce
85 Seventh Place East, Suite 500
St. Paul, MN 55101-2198

Re: 2024 Conservation Improvement Program Consolidated Filing
Docket Nos. E015/M-25-48, E015/CIP-23-93

In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act
Docket No. E,G-999/CI-22-624

Dear Mr. Seuffert and Mr. Wyckoff:

Attached please find via eFiling Minnesota Power's 2024 Energy Conservation and Optimization Program ("ECO") Consolidated Filing. This submittal includes an ECO Tracker Activity Report, a Financial Incentives Report, a Proposed Conservation Program Adjustment Factor, 2024 ECO Project Evaluations and a compliance with Department of Commerce ("DOC") orders section. Minnesota Power is filing this information pursuant to Minn. Stat. §§ 216B.241, 216B.16, subd, 6c, 216B.2401, and 216B.2411 and in compliance with Minnesota Public Utilities Commission ("MPUC") and DOC rules and orders relating to annual filings associated with Company-sponsored conservation program activities, including Minn. Rule 7690.0550.

Minnesota Power requests that the MPUC review the filed material and approve Minnesota Power's 2024 ECO Tracker Activity, Financial Incentives, and proposed Conservation Program Adjustment factor. Further, Minnesota Power requests that the DOC review and approve the evaluations of the various ECO projects included herein and the compliance with prior DOC orders. Minnesota Power has electronically filed this document and copies of this Cover Letter along with the Summary of Filing have been served on the parties on the attached service list.

Also included in this filing on page 23 is compliance for Order Point 3 from the September 12, 2023 order in Docket No. E,G-999/CI-22-624, In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act.

If you have any questions regarding this filing, please contact me at (218) 591-4870 or avang@mnpower.com.

Sincerely,



Analeisha Vang
Regulatory Compliance Specialist, Senior

AMV:th
Attach.

SUMMARY

Minnesota Power

2024 Energy Conservation and Optimization Program ("ECO") Consolidated Filing

EXECUTIVE SUMMARY

Minnesota Power (or, "the Company") is pleased to report its 2024 energy conservation program results:

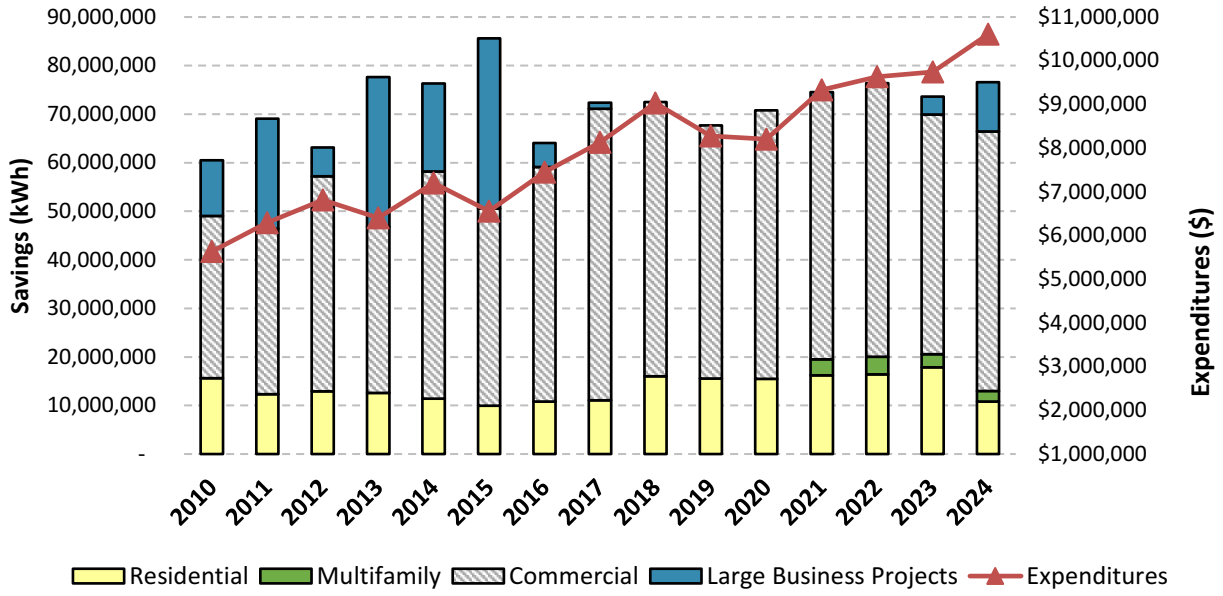
- Minnesota Power achieved energy savings of **3.0%** of gross annual retail energy sales,[1] well above the 1.75% minimum energy-savings goal set in the 2021 Energy Conservation and Optimization Act and detailed in the 2024-2026 Triennial Plan.[2]
- The Company achieved energy savings totaling **76,582,710 kilowatt hours ("kWh")**, which is **105%** of the approved energy-savings goal for the year. The Company also achieved demand savings of **5,942 kilowatts ("kW")**, which is **87%** of the approved demand-savings goal.
- Expenditures totaled **$10,604,663**, which was **84%** of the approved budget for 2024.

The following figure illustrates historical and recent kWh energy-savings achievements, along with ECO expenditures. While Minnesota Power continues to have a successful track record of exceeding the state energy savings goal, the cost of delivering on these goals continues to increase. The Company anticipates the trend of increasing costs will continue as economic changes impact the cost of both products and labor and more cost-effective measures reach market saturation. While Minnesota Power's ECO portfolio continues to be cost-effective overall, higher cost programs – especially those serving income-qualified customers – are becoming increasingly less cost-effective.

[1] In accordance with Minnesota Rules part 7690.1200, weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2024–2026 Triennial Plan.

[2] Minnesota Power's minimum goal was updated due to a newly ECO-exempt customer effective January 1, 2024. A Courtesy Notification was approved by the Department July 5, 2024.

Minnesota Power's 2010–2024 ECO Achievements



Minnesota Power's 2024 ECO Expenditures and Energy Savings

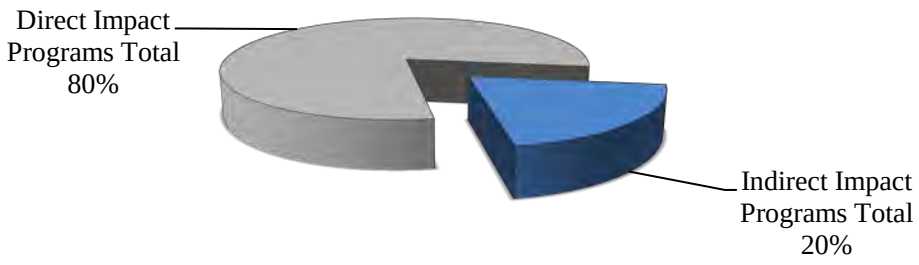
2024	*Expenditures*	*Energy Savings (kWh) at busbar*
Direct Savings Programs:		
Residential		
Energy Partners (Income-qualified)	$561,103	735,109
Home Efficiency (Residential)	$1,977,512	10,091,089
Multifamily		
Multifamily Efficiency	$360,725	2,151,517
Commercial		
Business Efficiency (Business/Commercial/Industrial/Agricultural)	$5,443,941	63,604,995
Indirect Savings Programs:		
Community Engagement	$430,399	
Energy Analysis	$497,313	
Research & Development	$230,419	
Evaluation & Planning	$630,717	
Minnesota Efficient Technology Accelerator, "ETA"	$281,840	
Regulatory Charges	$190,694	
Total	**$10,604,663**	**76,582,710**

STATUS REPORT

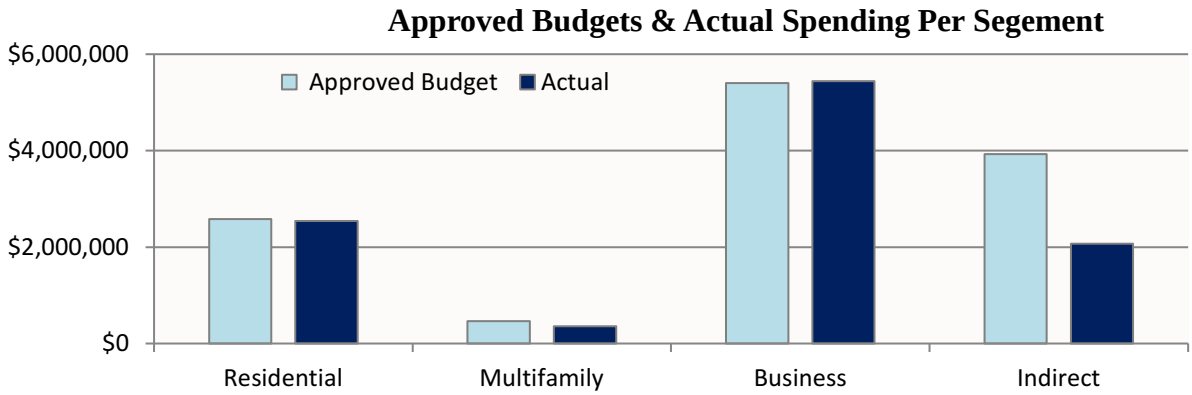
2024 ECO STATUS REPORT

Minnesota Power's energy conservation strategy provides a wide variety of program offerings to best serve its diverse customer mix. Each customer is unique in both their motivations for pursuing energy efficiency opportunities and their ability to engage in different offerings. With this knowledge, Minnesota Power provides a combination of traditional programs and innovative delivery strategies designed to address the needs and barriers of each customer segment including residential, multifamily and business. Minnesota Power's ECO portfolio includes a combination of "direct savings" and "indirect savings" programs that complement each other and provide for a balanced and meaningful customer experience.

2024 Program Spending By Direct and Indirect Savings Programs

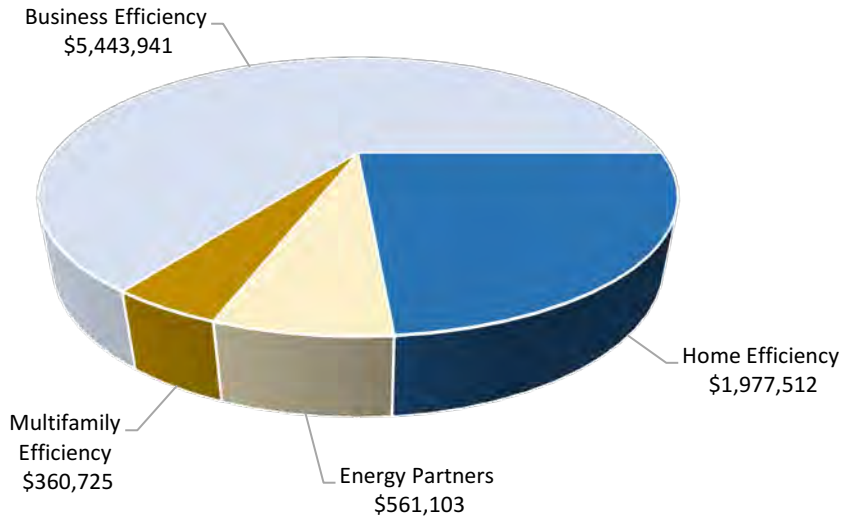


2024 Approved Budgets & Actual Spending Per Segment

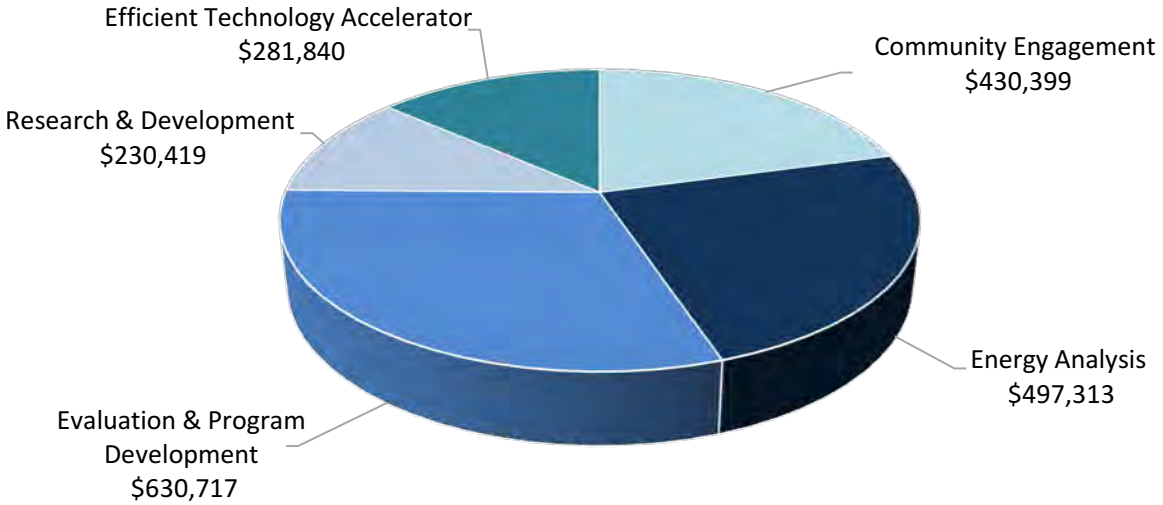


Investing in a range of programs is essential to keep Minnesota Power's program portfolio strong. Minnesota Power has included three vital customer segments along with indirect programs that effectively round out the portfolio in the 2024-2026 Triennial Plan. See the figures below for a breakdown of spending by program.

2024 Direct Programs Spending Breakdown

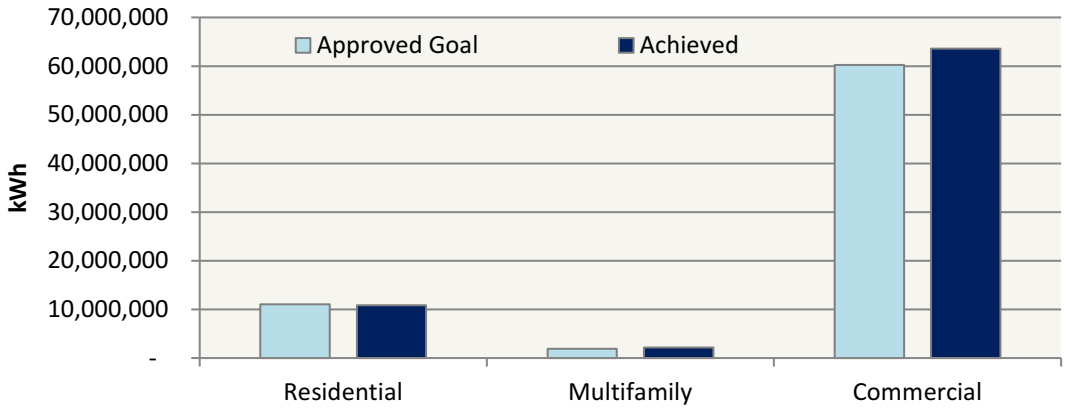


2024 Indirect Programs Spending Breakdown



In 2024, Minnesota Power's ECO portfolio successfully met its overall energy savings goal. Both the Commercial and Multifamily segments surpassed their individual savings goals, while the Residential segment fell slightly short of its target, as illustrated in the chart below. Savings and spending for each program is detailed in each programs section in the filing.

2024 Approved Savings Goals & Achievements per Segment



Looking Forward

There are many factors influencing the energy efficiency environment in Minnesota, including economic pressures leading to rising delivery costs, evolving state and federal policy, and changes in cost effectiveness. Minnesota Power has worked closely with customers, contractors, stakeholders, and regulators to ensure that programs are flexible and responsive to the evolving industry and has taken steps to modify programs as needed. However, additional actions will be required to ensure Minnesota Power's ECO portfolio continues to meet customer needs and encourages equitable access to customer programs as the environment perpetually evolves.

Program delivery costs have increased significantly in recent years. The combination of inflation and economic uncertainty have impacted customers' ability to make capital improvements to their homes and businesses. Additionally, attracting and retaining talent in northern Minnesota has continued to create challenges for customers, delivery partners, and the Company. Encouraging

customers to make energy-efficient investments has required higher incentives, more costly equipment and more resources than have historically been required.

Minnesota Power's ECO programming is currently undergoing a significant shift and transformation as a result of federal and state policy changes. While adjustments to the ECO statute were approved in the 2024 legislative session, implementation is still in progress. Despite ongoing development and implementation, the Company will be proposing to add efficient fuel switching measures to the ECO portfolio and is exploring load management activities, resulting in a more robust portfolio that further supports utility and state initiatives. Meanwhile, the IRA, which has introduced a significant amount of federal funding for energy efficiency projects, coupled with new state energy programs, present an opportunity for coordination. It will be critical for utilities and the Department to continue to coordinate on the design and eventual implementation of these programs to ensure that customers are able to maximize the benefits of ECO, IRA, and state programs. While effective coordination and implementation of these funds could help address the rising costs of utility conservation programs, there is significant uncertainty around actual impacts.

Meanwhile, the Company continues to assess the implications of the significant modifications made to the ECO evaluation framework and general program cost effectiveness transition from recent years. Recent changes include the addition of a new primary screening test designed to reflect the State's energy policy goals and objectives referred to as the Minnesota Cost Test ("MCT"), inclusion of new utility system and non-utility system impacts within the tests, and potential standardization of existing impacts that historically have been utility specific. In addition, cost effectiveness of efficiency programs overall has been heavily impacted by the increased efficiency standards of general service lighting. These changes, along with rising delivery costs and the new IRA programs described above, make it difficult to predict the overall cost-effectiveness of the ECO portfolio going forward. Flexibility to update and modify programs and portfolios will be more critical than ever as the Company navigates these challenges.

Minnesota Power will continue to work with customers, stakeholders, and regulators to ensure that programs are well-positioned to address challenges and opportunities associated with the rapidly evolving energy conservation and optimization landscape into the future. Minnesota Power remains committed to providing sustainable, inclusive, and cost-effective energy efficiency programs, with ongoing program development and increased efforts to raise program awareness and participation.

Minnestota Power's 2024 ECO Expenditures & Achievements

2024	*Expenditures*				*Energy Savings (kWh @ Busbar)*				*Demand Savings (kW @ Busbar)*				*Participation*			
Direct Impact Programs	***Filed Budget***	***Approved Budget***	***Actual***	***Percent of Approved***	***Filed Goal***	***Approved Goal***	***Achieved***	***Percent to Goal***	***Filed Goal***	***Approved Goal***	***Achieved***	***Percent to Goal***	***Filed Goal***	***Approved Goal***	***Achieved***	***Percent to Goal***
Home Efficiency	$ 1,930,969	$ 1,933,669	$ 1,977,511.60	102%	10,330,910	10,346,997	10,091,089	98%	1,124	1,126	1,014.3	90%	66,701	66,710	106,536	160%
Energy Partners	$ 642,993	$ 644,687	$ 561,102.87	87%	722,378	725,226	735,109	101%	67	68	71.8	106%	2,156	2,201	2,479	113%
Multifamily Efficiency	$ 465,012	$ 465,612	$ 360,724.81	77%	1,897,574	1,898,945	2,151,517	113%	130	134	462.8	345%	97	99	186	188%
Business Efficiency	$ 5,398,621	$ 5,399,821	$ 5,443,941.07	101%	60,222,957	60,225,700	63,604,995	106%	5,514	5,521	4,393.5	80%	1,344	1,348	1,308	97%
Direct Impact Programs Total	**$ 8,437,594**	**$ 8,443,788**	**$ 8,343,280**	**99%**	**73,173,819**	**73,196,868**	**76,582,710**	**105%**	**6,835.8**	**6,848.7**	**5,942.4**	**87%**	**70,298**	**70,358**	**110,509**	**157%**
Indirect Impact Programs																
Community Engagement	$ 983,500	$ 983,500	$ 430,399	44%									110,800	110,800	98,694	89%
Energy Analysis	$ 1,454,250	$ 1,454,250	$ 497,313	34%									2,362	2,362	3,340	141%
Evaluation & Planning	$ 860,500	$ 860,500	$ 630,717	73%												
Research & Development	$ 350,000	$ 350,000	$ 230,419	66%												
Efficient Technology Accelerator	$ 245,840	$ 281,841	$ 281,840	100%												
Indirect Impact Programs Total	**$ 3,894,090**	**$ 3,930,091**	**$ 2,070,688**	**53%**	-	-	-						**113,162**	**113,162**	**102,034**	**90%**
Regulatory Charges	$ 200,000	$ 200,000	$ 190,694	95%												
Total	**$ 12,531,684**	**$ 12,573,879**	**$ 10,604,663**	**84%**	**73,173,819**	**73,196,868**	**76,582,710**	**105%**	**6,835.8**	**6,848.7**	**5,942.4**	**87%**	**183,460**	**183,520**	**212,543**	**116%**

APPENDIX B: DEMAND SIDE MANAGEMENT AND DISTRIBUTED RESOURCES

This Appendix of the 2025-2039 Integrated Resource Plan ("2025 Plan") contains information regarding Minnesota Power's (or the "Company") planning and strategies for demand side management ("DSM"), including energy efficiency ("EE") and energy conservation and optimization ("ECO"), along with Residential Time-of-Day ("TOD"), alternative demand side management programs, distributed generation ("DG"), and microgrids. This Appendix is broken into five parts as detailed below.

1. Minnesota Power's EE Resource Alternatives and ECO Strategy;
2. Residential TOD;
3. Alternative Demand Side Management Programs;
4. Distributed Generation; and
5. Microgrids.

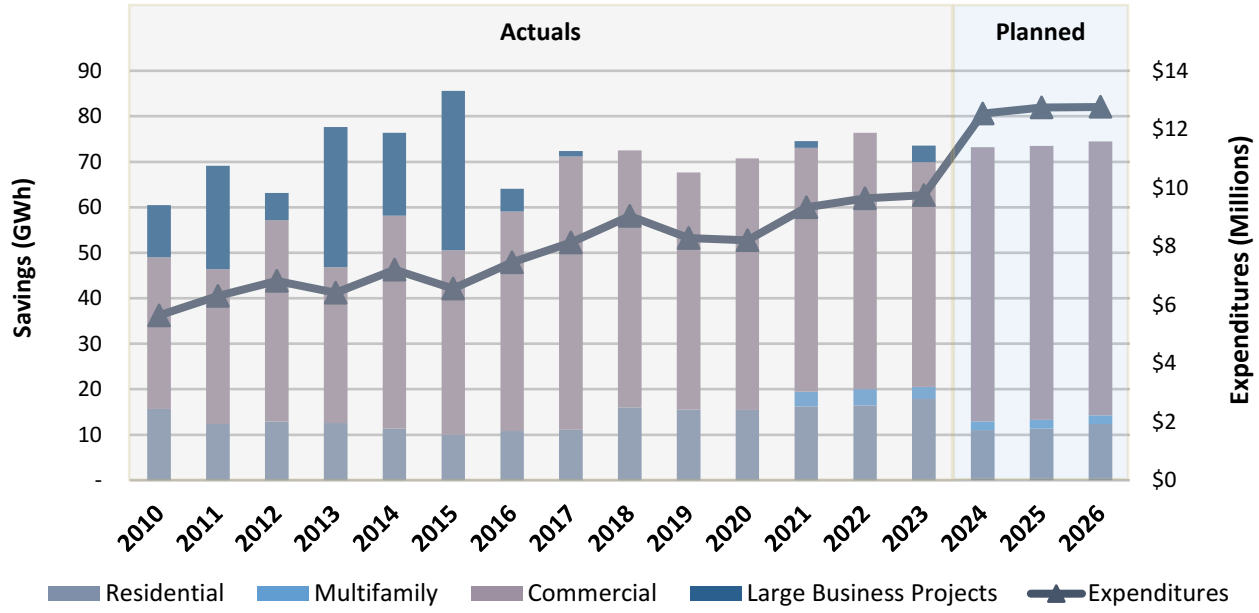
A. Part 1: Minnesota Power's EE Resource Alternatives and ECO Strategy

Minnesota Power is committed to providing sustainable energy-efficiency programs, as demonstrated by its strong historical conservation program achievements. Since the Minnesota Next Generation Energy Act of 2007 ("NGEA"), Minnesota Power has been refining and expanding upon its proven conservation program platform to deliver cost-effective savings, customer value, and environmental benefits. The Energy Conservation and Optimization Act of 2021 ("ECO Act") provided a timely pathway for building on core conservation program offerings and expanding those to reach more customers while providing a broader suite of programs and services. Minnesota Power filed its 2024-2026 Triennial ECO Plan on June 30, 2023,[1] and remains dedicated to continuous program improvement. Ongoing conservation initiatives are part of Minnesota Power's broader *Energy**Forward*** resource strategy – a strategy designed to provide a safe, reliable, and affordable power supply while identifying sustainable solutions for compliance with Minnesota's Carbon-Free Electricity Standard. This part of the appendix discusses the development of the Company's energy conservation targets included in the 2024-2026 ECO Triennial Plan filing[2] and the 2025 IRP baseline assumptions, as well as two increased EE alternative resource scenarios.

Figure 1 below reflects historical (first year) savings achievements and the proposed savings goals for 2024-2026, as filed in the latest ECO Triennial Plan. Minnesota Power, together with its customers, community stakeholders, and trade allies, has achieved great success through its energy conservation programs. The Company has delivered energy savings at or above the state's 1.5 percent energy-savings goal since 2010 when the goal went into effect, all while maintaining focus on targeted program objectives – quality installations, informed decisions, EE, and safety. The proposed goal for 2024-2026 and the assumed EE in the baseline forecast, 2.9 percent of sales, reflect the Company's intent to continue achieving significant savings and is well above the state's new ECO goal of 1.75 percent that became effective with the ECO Act.

[1] *Minnesota Power's 2024-2026 Triennial Energy Conservation and Optimization Program Filing*, Docket No. E-015/CIP-23-93, ECO Triennial Compliance Filing (June 30, 2023)
[2] *Minnesota Power's 2021-2023 Triennial Conservation Improvement Program Filing*, Docket No. E-015/CIP-20-476, Petition (July 1, 2020).

Figure 1. Minnesota Power Historical ECO Achievements and 2024-2026 Goals



2025 IRP Baseline Assumptions and the 2024-2026 ECO Triennial

For purposes of both ECO Triennial planning and 2025 IRP modeling, Minnesota Power started with an approach similar to the 2021 IRP. Assumptions used in the 2021-2023 ECO Triennial and the 2021 IRP were developed using the 2020-2029 Minnesota State Demand Side Management Potential Study ("Potential Study") funded by the Minnesota Department of Commerce and led by the Center for Energy and Environment ("CEE").[3] During the study, Minnesota Power worked closely with CEE to update assumptions used in the Minnesota Power specific projections to more accurately capture the Company's specific territory, customer base, and historical experience with energy efficiency programs. Individual program targets and technology contributions were updated to reflect recent historical experience, current policy, industry and market conditions, and realistic expectations for the coming years.[4] Subsequently, the 2021 IRP informed the Company's goals for the 2024-2026 ECO plan, which was used as the baseline EE assumption built into the 2025 IRP customer demand forecast. These savings targets are well above the State of Minnesota's 1.75 percent minimum energy-savings goal for ECO,[5] which equates to roughly 45 gigawatt hours ("GWh") on Minnesota Power's system. The Baseline scenario assumes these savings targets will equate to roughly 74 GWh on Minnesota Power's system in 2024-2026. The savings goals in the ECO Triennial Plan and the efficiency levels assumed in the baseline assumptions for the IRP are aggressive, but the Company believes these

[3] *See* Minnesota Department of Commerce, "Minnesota Energy Efficiency Potential Study: 2020-2029," (December 4, 2018), available at https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf.

[4] The process of updating the CEE potential projections and method used to incorporate them into the 2020 load forecast are documented in the Company's AFR2020, included as Appendix A in the 2021 IRP.

[5] Minn. Stat. § 216B.241, subd. 1c(b) ("A public utility providing electric service has an annual energy-savings goal equivalent to 1.75 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (c).The savings goals must be calculated based on the most recent three-year weather-normalized average.").

are achievable. Individual program targets and technology contributions have been updated to reflect recent historical experience, current policy, industry and market conditions, and realistic expectations for the coming years. As many of these factors are still evolving, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty.

Summary of Alternative Energy Efficiency Scenarios

Based on the current ECO strategy, and analysis of historical performance and future opportunities, Minnesota Power provided two alternative EE scenarios with additional energy and capacity savings above the Baseline Scenario (built into the base/expected 2024 Annual Electric Utility Forecast Report ("AFR2024") forecast). The Company further developed cost projections consistent with each outlook. The two alternative energy efficiency scenarios evaluated in the IRP analysis are:

1. "High" Scenario: modeled to reflect savings of 3.5 percent of sales, and
2. "Very High" Scenario: modeled to reflect savings of 4 percent of sales.

These scenarios were incorporated in the EnCompass modeling process as supply side alternatives in the capacity expansion plan analysis.

The alternative efficiency scenarios ("High" and "Very High") considered in the IRP analysis begin in the year 2027. These alternatives were not modeled as an option for 2024-2026 due to currently approved savings levels and the limited ability to significantly increase EE above the approved 2024-2026 ECO Triennial Plan. All three EE scenarios assume new program implementation costs (and new savings) each year through 2039. For the purposes of modeling the alternative scenarios in the 2025 IRP, only the additional costs and additional first year MWh/MW savings above the baseline are included. A high-level summary of the baseline EE (assumed in the forecast) and the increased efficiency scenarios modeled in the resource plan are shown in Table 1 and includes the following:

- Percentage of Sales: Represents the level of 2027 savings under each scenario as a percentage of average weather normalized 2020-2022, non-ECO exempt retail sales—the baseline for the 2024-2026 ECO Triennial Plan.[6]
- Energy: Total estimated first year energy savings associated with each scenario for the year 2027.
- Energy Above Base: The additional MWh associated with each scenario in terms of first year savings as compared to the baseline plan (EE assumed in forecast).
- Seasonal Peak: Estimated first year MW demand savings coincident with Midcontinent Independent System Operator ("MISO"). Table 1 below shows summer peak for the year 2027 as an example.
- Summer Peak Reduction Above Base: The additional first year MW demand savings associated with the scenario as compared to the baseline plan.
- Incentives: Program costs directly related to incentivizing customers to install/complete an efficiency measure by covering part or all of the incremental costs associated with implementing the measure.
- Non-Incentives: All other costs incurred by the Company to implement the 2027 EE plan.

[6] In accordance with Minn. R. 7690.1200, 2020-2022 weather-normalized average retail energy sales were used to calculate the minimum electric savings goal for Minnesota Power's 2024-2026 Triennial ECO plan. Effective January 1, 2024, adjusted retail energy sales were approved by the Department of Commerce due to a newly exempt ECO Customer. This equated to 2,555,346,232 kWh, net of ECO exempt customers. Savings as a percent of sales in Table 1 were calculated using this figure.

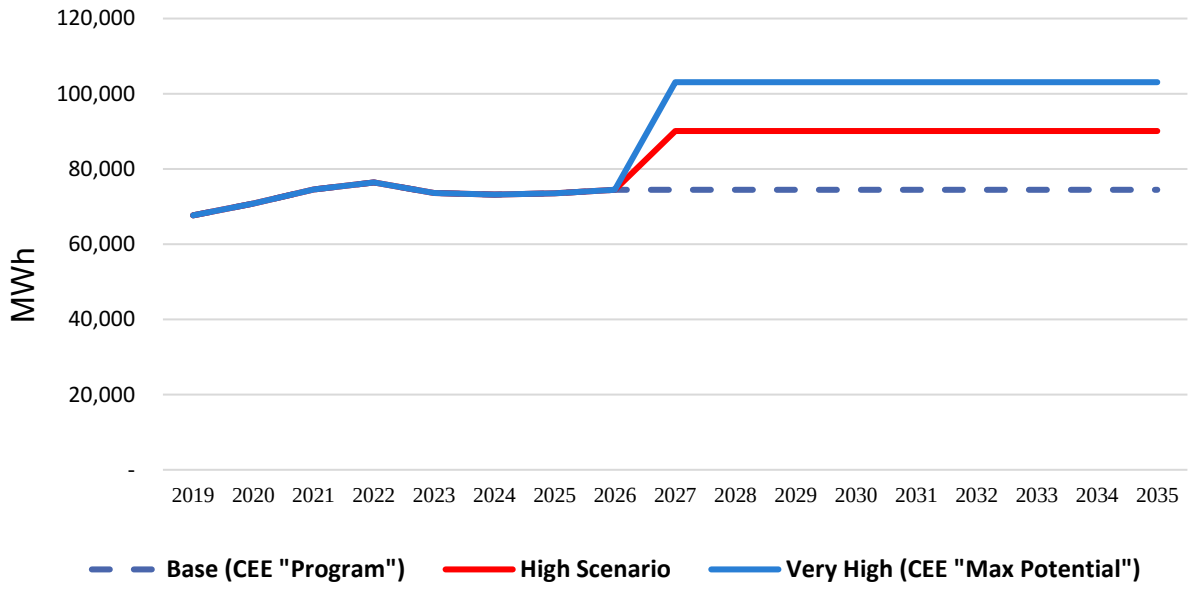
- Total Cost: The estimated total program costs assumed to achieve the level of savings associated with each scenario in the year 2027.
- Total Cost Above Base: The estimated additional spending needed to achieve the incremental savings as compared with the existing plan for the year 2027.

Table 1. Summary of Energy Efficiency Scenarios

		First Year Annual Savings at Generator (Energy: GWh/Peak: MW)				First Year Program Costs (Millions $)			
Scenarios	% of Sales (Rounded)	Energy	Energy Above Base	MP Summer Peak Reduction	Summer Peak Reduction Above Base	Incentives	Non-Incentives	Total Costs	Total Costs Above Base
Base	2.91%	74.5	-	6.8	-	$4.41	$8.15	$12.56	-
High	3.53%	90.1	15.6	8.3	1.5	$14.79	$10.27	$25.06	$12.50
Very High	4.03%	103.1	28.6	9.6	2.8	$32.73	$12.39	$45.12	$32.56

Figure 2 below reflects the first year EE savings (measured at the generator) assumed in each year through 2039 for each of the three scenarios.

Figure 2. 2025 IRP Energy Efficiency Scenarios



Energy Efficiency Scenario Development and Assumptions

As previously noted, Minnesota Power's 2021 IRP was the starting point for developing the 2024-2026 ECO triennial which was used as the Baseline Scenario. The two alternative EE scenarios, which reflect savings levels equivalent to 3.5 percent and 4 percent of eligible sales, were developed by increasing the measure participation assumptions from the baseline scenario

proportionally to arrive at the respective savings levels. The costs for the two higher scenarios were developed using a similar approach to the 2021 IRP EE scenarios. Those incentive costs were increased by setting them to a specific percent of incremental costs and adjusting the non-incentive costs to reflect more aggressive levels of program design, delivery, and marketing efforts anticipated to achieve savings beyond the baseline.

Savings Targets and Contribution

Savings contributions by class and technology for the baseline and planning scenarios align with the savings targets assumed in the 2024-2026 ECO plan. They reflect historical patterns, recent experience, and factors that may impact specific measure or class level savings opportunities including policy changes, market penetration, and updates to approved measures and savings calculations as defined in the Technical Reference Manual ("TRM").[7] Updated avoided costs and net benefit estimates were also taken into account to evaluate changes in cost-effectiveness for various technologies compared to in the past.

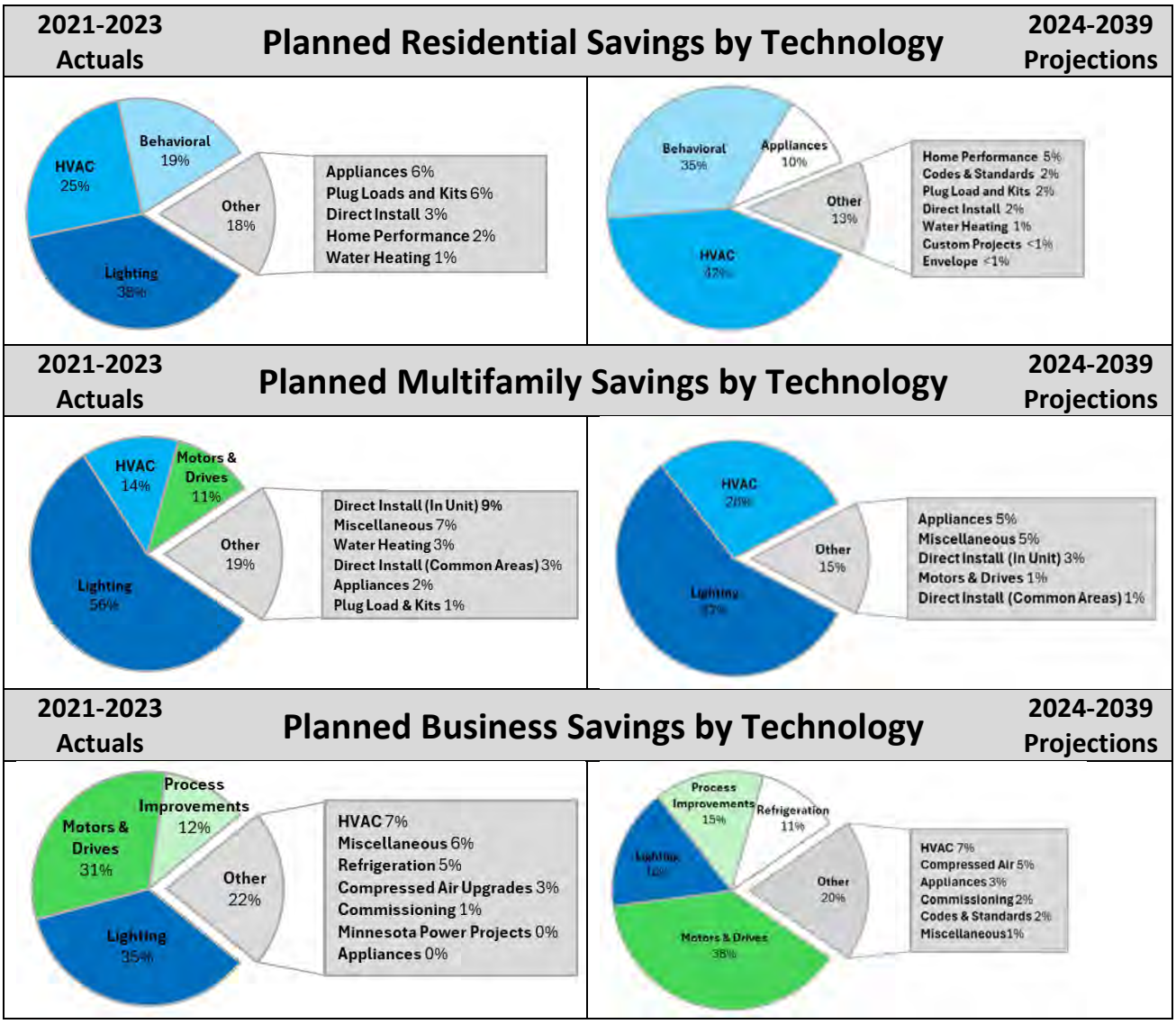
The most significant change to the assumed measure contributions for each EE IRP scenario is the decrease in lighting measures. Minnesota Power updated savings contributions to reflect that new opportunities for lighting savings are significantly less available in residential programs and are diminished in the business program due to changing codes and standards impacting lighting measure baselines and market saturation of commercial and industrial efficient lighting.

Historically, lighting has been a major contributor to all programs requiring a significant shift in measure makeup. For residential, this resulted in a significant shift to heating, ventilation & air conditioning ("HVAC") savings. For business, this resulted in a noticeable shift away from lighting into other evolving technologies such as motors and heating, ventilation, air conditioning & refrigeration ("HVACR"). The impact of lighting measures on the multifamily customer segment is less predictable as multifamily is a relatively small segment and, historically, projects in this segment were incorporated into the business and residential programs. It was first separated out into its own segment in the 2021-2023 Triennial period and future savings contributions are projected to come from similar technology categories. However, given the size of this segment and the limited pool of participants, actual savings contributions could vary from these assumptions in any given year.

Figure 3 reflects actual savings contributions by technology for the 2021-2023 period and the projected savings contributions by technology for 2024 and beyond. For the alternative savings scenarios (High and Very High), all measures in the Baseline scenario were scaled by the same percentage to achieve the targeted savings levels for each program.

[7] Minnesota Department of Commerce, "State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs," (Jan. 20, 2020), available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0CDC86F-0000-C832-A29A-F7752BF4A0D9}&documentTitle=20201-159365-02.

Figure 3. Planned Savings by Technology



Scenario Cost Development

Cost assumptions were developed for each scenario for 2027 through 2039. For use in the 2025 IRP analysis, the costs associated with the High and Very High scenarios are incremental to the Baseline scenario. Cost assumptions were made for customer incentives and non-incentive costs which include program design, delivery, administration, evaluation, and marketing. For the baseline scenario, budgets from the approved 2024-2026 ECO Triennial Plan were used. For each of the High and Very High EE scenarios, customer incentives were set to a specific percent of incremental costs (where incremental cost is the difference between the cost of the standard efficiency product or action, or sometimes purchasing nothing/taking no action, compared to the cost of the efficient product or action) and non-incentive costs were increased to reflect the elevated level of program design, delivery, and marketing needed to achieve the additional savings.

Baseline Scenario

2027 cost assumptions for the Baseline scenario were developed to serve as the baseline costs against which the costs for the two higher scenarios would be compared. The Company assumed:

- Customer incentives established in the approved 2024-2026 ECO Triennial Plan. The percent of incremental costs assumed here range based on a variety of factors considered during Triennial planning including cost-effectiveness of the measure, market saturation, customer demand, etc.
- Robust program design and marketing.

High Scenario

This represents anticipated costs associated with increasing savings to 3.5 percent of eligible retail sales. The Company assumed:

- Customer incentives are set to at least 50 percent of incremental measure costs. For measures where the baseline incentive is below 50 percent of the incremental cost, the incentive is increased to 50 percent. For measures where the baseline incentive is already above 50 percent of the incremental cost, the incentive cost is assumed to be the same as in the baseline scenario.
- Aggressive program design and marketing.

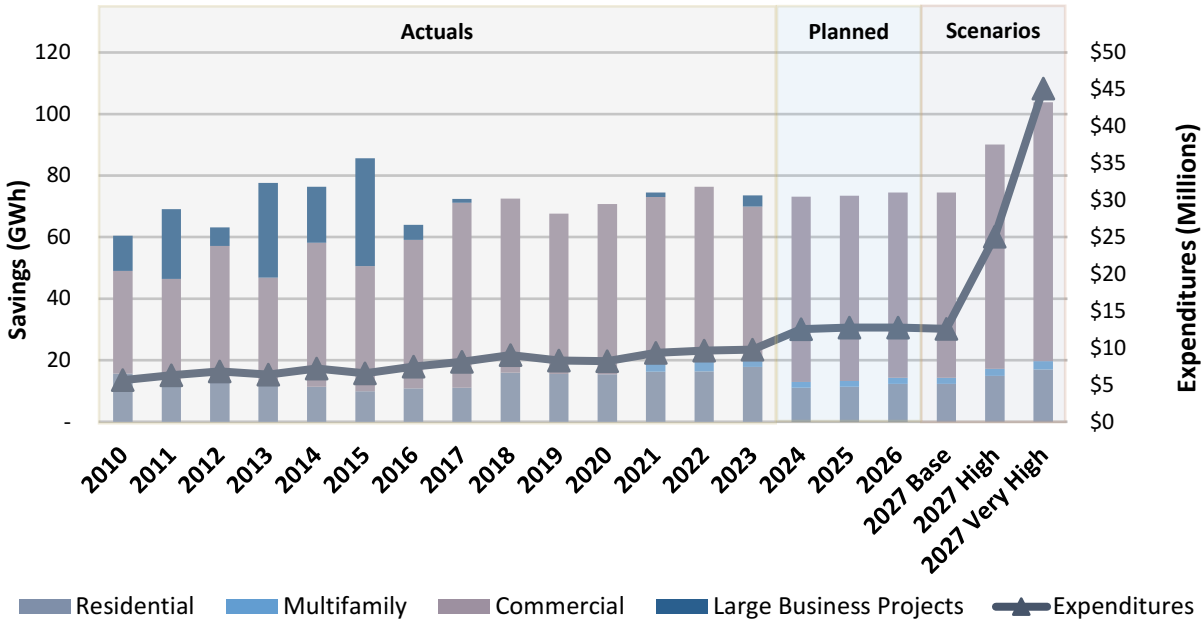
Very High Scenario

This represents the anticipated costs associated with increasing savings to 4 percent of eligible retail sales. The Company assumed:

- Customer incentives are set at 100 percent of incremental measure costs.
- Aggressive program design and marketing.

Figure 4 below expands on the Minnesota Power Historical ECO Performance graph (Figure 1) to include the planned costs and savings for 2024-2026 (as filed in the approved Triennial plan), and 2027 costs and savings as modeled for the Baseline Scenario and two alternative scenarios used in the 2025 IRP analysis:

Figure 4. Historical, Planned, and Modeled CIP Energy Savings (First Year) and Costs

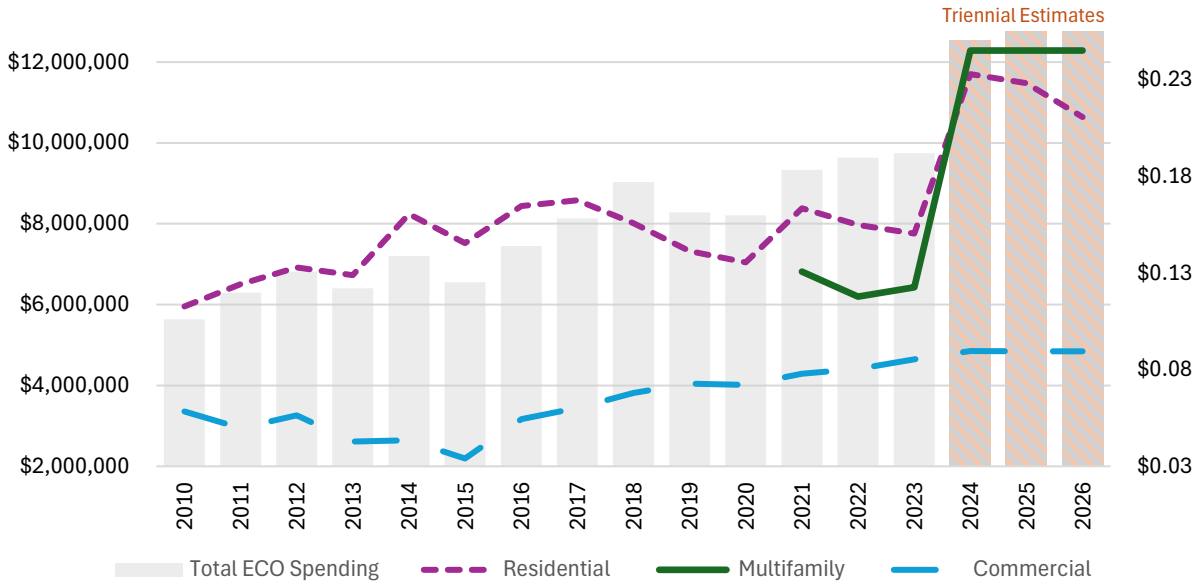


Discussion of Increasing Costs in an Evolving Energy Efficiency Landscape

In developing costs for the 2025 IRP EE scenarios, Minnesota Power started with the budget assumptions approved in the 2024-2026 ECO Triennial filing. Stronger incentive levels and more aggressive program design and marketing will be critical to deliver at the levels discussed in the 2025 IRP. Reduced opportunities for low-barrier measures, changes to measure codes and standards, a changing landscape of market saturation and industry policy, lasting impacts of inflation, and ongoing supply chain and workforce challenges have and continue to impact the need for increased program spending to achieve at or above historical savings levels.

Historical trends show Minnesota Power's overall program costs increasing over time and the Company expects that trend to accelerate. Figure 5 below shows how program costs per kWh have trended over time. Since 2015, commercial and industrial costs per kWh saved have steadily increased and the Company anticipates a significant increase in costs per kWh for the residential and multifamily sectors as well. However, with so many aspects of the energy industry and economy evolving, in order to achieve higher savings goals, the cost per kWh saved will not only continue to trend up, but it will also increase more significantly with higher levels of EE.

Figure 5. Total Spending and Cost per kWh per Program Trending



While Minnesota Power has continued its proven track record of successful program performance, the Company acknowledges that the current energy-efficiency environment is rapidly evolving in ways that will continue to present new challenges. Given that new opportunities for lighting savings are significantly diminished, a transition towards other technologies will be required to maintain savings goals across all programs. Historically, lighting has been one of the most cost-effective and prevalent measures in the ECO portfolio and, in 2023, accounted for nearly 28 GWh in savings (38 percent of total savings). The types of technologies that need to replace these savings are more costly measures that customers may not be as ready (or financially able) to adopt without significant education and incentives to do so. Changing baselines, uncertain economic conditions, high rates of inflation, and workforce constraints will all contribute to Minnesota Power's ability to offer cost-effective, meaningful programs to customers. Increased education and outreach, along with higher rebate levels drive the increase in costs assumed in the 2024-2026 Triennial and 2027 Baseline scenario as compared to the historical costs.

Economic conditions and lasting impacts from the COVID-19 pandemic have affected recent and anticipated program costs in a variety of ways. Increased costs of living for residential customers and higher operating costs for businesses make it more difficult to prioritize energy efficiency investments. Residential customers often must choose between spending money on energy efficiency and other life necessities, both of which have become more expensive. The opportunity cost of updating home appliances or HVAC systems, etc., is greater now than it has been historically. Similarly, commercial customers are facing rising business expenses that impact their ability to spend on energy efficiency measures. To continue achieving high savings levels, Minnesota Power must increase efforts to help customers overcome these financial barriers, while also shouldering higher program delivery costs.

Furthermore, new state and federal policies present both opportunities and challenges for delivering programs that meet customer needs. Specifically, the ECO Act of 2021 and related statute amendments passed during the 2024 legislative session allow for significant expansion of traditional energy conservation programs. While the ECO Act significantly modified the framework for existing utility programs, state and federal energy policies have the potential to be equally as

impactful. Minnesota Power continues to work collaboratively with stakeholders to ensure that new state and federal rebate programs are designed and implemented in a way that maximizes benefits to customers and do not unintentionally cannibalize resources. Additionally, the Company is monitoring federal policy changes to better understand potential impacts to program offerings. As these policies evolve, the Company will continue to monitor and anticipate the impacts on ECO programs and related costs.

Scenario Details

The following tables include the plan parameters for each scenario (savings, costs, participation for Baseline, High, and Very High scenarios).

Table 2. Year 2024 Energy and Demand Savings (MISO Summer Peak)

	Base kWh	High kWh	Very High kWh	Base kW	High kW	Very High kW
Res	**11,622,274**	**14,062,951**	**16,038,738**	**1,214.0**	**1,468.9**	**1,675.3**
Appliances	893,445	1,081,069	1,232,955	252.3	305.3	348.2
HVAC	4,702,513	5,690,040	6,489,468	386.3	467.4	533.1
Envelope	1,031	1,248	1,423	0.1	0.1	0.1
Home Performance	543,097	657,148	749,474	21.9	26.6	30.3
Water Heating	71,555	86,582	98,746	5.9	7.2	8.2
Plug Load and Kits	176,753	213,872	243,920	14.8	17.9	20.4
Direct Install	201,179	243,426	277,626	16.1	19.5	22.2
Behavioral	4,344,777	5,257,181	5,995,793	495.6	599.7	684.0
Codes and Standards	687,923	832,387	949,334	20.9	25.3	28.8
Administrative Costs	0	0	0	0.0	0.0	0.0
Low Income	**722,378**	**874,078**	**996,882**	**67.2**	**81.3**	**92.8**
Appliances	284,474	344,214	392,575	34.1	41.2	47.0
HVAC	223,213	270,088	308,034	14.7	17.8	20.3
Water Heating	103,214	124,889	142,435	8.6	10.4	11.8
Plug Load and Kits	37,967	45,941	52,395	4.2	5.0	5.7
Home Performance	10,972	13,276	15,141	0.4	0.5	0.6
Custom Project	62,538	75,672	86,303	5.3	6.4	7.3
Administrative Costs	0	0	0	0.0	0.0	0.0
Multi-Family Custom	**1,897,574**	**2,296,064**	**2,618,652**	**130.4**	**157.8**	**180.0**
Lighting	1,077,200	1,303,412	1,486,536	41.7	50.4	57.5
Motors and Drives	24,057	29,109	33,199	0.3	0.3	0.4
HVAC	528,397	639,360	729,188	56.7	68.6	78.2
Miscellaneous	84,105	101,768	116,066	0.3	0.3	0.4
Appliances	99,939	120,926	137,915	22.5	27.2	31.0
Direct Install - In Unit	63,336	76,637	87,404	6.8	8.2	9.4
Direct Install- Common Area	20,539	24,852	28,344	2.3	2.7	3.1
Administrative Costs	0	0	0	0.0	0.0	0.0

	Base kWh	High kWh	Very High kWh	Base kW	High kW	Very High kW
C&I	**60,211,749**	**72,856,216**	**84,150,561**	**5,456.6**	**6,602.5**	**7,661.1**
Lighting	8,464,818	10,242,430	11,681,449	1,232.4	1,491.2	1,700.8
Refrigeration	6,707,469	8,116,038	9,256,308	1,138.7	1,377.8	1,571.4
Motors and Drives	23,108,804	27,961,653	31,890,150	170.8	206.7	235.7
HVAC	4,046,610	4,896,399	5,584,322	561.8	679.8	775.4
Compressed Air Upgrades	2,770,689	3,352,533	3,823,550	302.1	365.5	416.9
Process Improvements	8,985,697	10,872,694	12,400,262	966.3	1,169.2	1,333.4
Appliances	1,599,732	1,935,675	2,207,630	682.6	825.9	942.0
Miscellaneous	852,787	1,031,872	1,176,845	86.5	104.6	119.3
Commissioning	1,126,425	1,362,975	1,554,467	0.0	0.0	0.0
Codes and Standards	2,548,717	3,083,947	4,575,577	315.5	381.7	566.4
Administrative Costs	0	0	0	0.0	0.0	0.0
Indirect	**0**	**0**	**0**	**0.0**	**0.0**	**0.0**
Indirect Program Costs	0	0	0	0.0	0.0	0.0
Grand Total	**74,453,975**	**90,089,309**	**103,804,833**	**6,868.2**	**8,310.6**	**9,609.2**

Table 3. Year 2024 Participation

	Base Scenario Participants	High Scenario Participants	Very High Scenario Participants
Res	**76,701**	**92,809**	**105,849**
Appliances	1,748	2,115	2,412
HVAC	874	1,058	1,206
Envelope	10	12	14
Home Performance	25	30	35
Water Heating	42	51	58
Plug Load and Kits	300	363	414
Direct Install	1,701	2,058	2,347
Behavioral	72,000	87,120	99,360
Codes and Standards	1	2	3
Administrative Costs	0	0	0
Low Income	**2,156**	**2,609**	**2,975**
Appliances	367	444	506
HVAC	380	460	524
Water Heating	607	734	838
Plug Load and Kits	785	950	1,083
Home Performance	2	2	3
Custom Project	15	18	21
Administrative Costs	0	0	0

	Base Scenario Participants	High Scenario Participants	Very High Scenario Participants
Multi-Family Custom	**97**	**117**	**133**
Lighting	32	38	43
Motors and Drives	1	1	1
HVAC	16	19	22
Miscellaneous	4	5	6
Appliances	15	18	20
Direct Install - In Unit	17	21	23
Direct Install - Common Area	13	16	18
Administrative Costs	0	0	0
C&I	**1,269**	**1,535**	**1,753**
Lighting	248	300	342
Refrigeration	157	190	217
Motors and Drives	291	352	402
HVAC	164	198	226
Compressed Air Upgrades	44	53	61
Process Improvements	113	137	156
Appliances	222	269	306
Miscellaneous	10	12	14
Commissioning	19	23	26
Codes and Standards	1	1	3
Administrative Costs	0	0	0
Indirect	**0**	**0**	**0**
Indirect Program Costs	0	0	0
Grand Total	**80,223**	**97,071**	**110,710**

Table 4. Year 2027 Costs

	Base Scenario	High Scenario	Very High Scenario
Residential	**$1,958,077.37**	**$3,043,150.59**	**$5,315,230.58**
Appliances	$118,970.00	$140,969.72	$232,521.72
HVAC	$538,465.00	$1,593,374.00	$3,634,472.88
Envelope	$150.00	$326.70	$745.20
Home Performance	$95,000.00	$95,000.00	$179,986.50
Water Heating	$12,800.00	$20,787.80	$47,416.80
Plug Load and Kits	$9,500.00	$9,500.00	$13,110.00
Direct Install	$16,433.20	$16,433.20	$22,677.82
Behavioral	$35,000.00	$35,000.00	$48,300.00
Codes and Standards	$11,159.17	$11,159.17	$15,399.66
Administrative Costs	$1,120,600.00	$1,120,600.00	$1,120,600.00
Low Income	**$642,992.50**	**$642,992.50**	**$823,333.85**
Appliances	$182,819.50	$182,819.50	$252,290.91
HVAC	$127,797.40	$127,797.40	$176,360.41
Water Heating	$93,645.60	$93,645.60	$129,230.93
Plug Load and Kits	$7,320.00	$7,320.00	$10,101.60
Home Performance	$6,000.00	$6,000.00	$8,280.00
Custom Project	$57,000.00	$57,000.00	$78,660.00
Administrative Costs	$168,410.00	$168,410.00	$168,410.00
Multi-Family Custom	**$465,011.75**	**$549,628.27**	**$828,153.83**
Lighting	$53,556.25	$53,556.25	$92,384.62
Motors and Drives	$1,713.12	$4,200.60	$9,581.52
HVAC	$194,221.94	$194,221.94	$291,959.42
Miscellaneous	$8,528.81	$90,657.85	$206,789.80
Appliances	$12,688.40	$12,688.40	$18,580.09
Direct Install - In Unit	$36,397.50	$36,397.50	$50,228.56
Direct Install - Common Area	$1,905.73	$1,905.73	$2,629.82
Administrative Costs	$156,000.00	$156,000.00	$156,000.00
C&I	**$5,388,111.45**	**$14,602,535.81**	**$29,808,890.51**
Lighting	$572,307.00	$1,516,190.21	$3,458,417.34
Refrigeration	$266,176.00	$1,682,766.61	$3,838,376.73
Motors and Drives	$812,197.00	$3,251,394.30	$7,416,403.53
HVAC	$409,559.00	$1,288,532.44	$2,939,131.84
Compressed Air Upgrades	$49,506.00	$293,713.63	$669,958.37
Process Improvements	$358,483.00	$2,990,051.98	$6,820,283.84
Appliances	$104,440.00	$526,023.77	$1,199,855.88
Miscellaneous	$28,944.00	$267,363.42	$609,853.74
Commissioning	$174,534.00	$174,534.00	$240,856.92
Codes and Standards	$9,965.45	$9,965.45	$13,752.32
Administrative Costs	$2,602,000.00	$2,602,000.00	$2,602,000.00
Indirect	**$4,107,361.00**	$6,227,497.46	$8,347,633.92
Indirect Program Costs	$4,107,361.00	$6,227,497.46	$8,347,633.92
Grand Total	**$12,561,554.07**	**$25,065,804.63**	**$45,123,242.69**

Table 5. Baseline Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,133,865.00	$4,407,183.00	$12,541,048.00	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,154,371.00	$4,412,814.94	$12,567,185.94	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	37,878	20,586	20,168	222,256,517
2028	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	50,011	26,958	26,487	292,498,595
2029	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	62,108	33,295	32,772	362,438,953
2030	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	74,097	39,540	39,053	432,251,085
2031	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	86,085	45,784	45,334	502,063,217
2032	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	98,053	52,019	51,598	571,757,129
2033	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	109,882	58,170	57,738	640,729,172
2034	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	121,682	64,302	63,852	709,525,474
2035	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	131,856	69,446	68,936	767,877,919
2036	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	142,023	74,585	74,013	826,192,455
2037	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	150,052	78,128	78,165	873,075,338
2038	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	158,384	81,922	82,454	921,623,798
2039	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	166,697	85,705	86,726	970,075,651

Table 6. High Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,133,865.00	$4,412,814.94	$12,546,679.94	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$8,154,371.00	$4,407,183.00	$12,561,554.00	15,323	8,311	8,246	90,089,309	40,538	22,028	21,599	237,891,852
2028	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	55,327	29,842	29,347	323,763,044
2029	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	70,077	37,621	37,057	409,314,931
2030	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	84,607	45,196	44,658	493,814,538
2031	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	99,136	52,772	52,259	578,314,146
2032	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	113,621	60,317	59,842	662,668,606
2033	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	127,967	67,780	67,301	746,301,196
2034	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	142,280	75,222	74,730	829,733,220
2035	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	154,938	81,657	81,104	902,569,794
2036	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	167,583	88,084	87,465	975,331,553
2037	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	177,749	92,707	92,685	1,034,468,450
2038	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	188,216	97,580	98,040	1,095,262,962
2039	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	198,285	102,162	103,217	1,153,940,114

Table 7. Very High Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,154,371.00	$4,407,183.00	$12,546,679.93	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,133,865.00	$4,412,814.94	$12,561,554.06	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$12,394,643.92	$32,728,598.77	$45,123,242.69	17,607	8,311	9,531	103,804,833	42,822	23,327	22,884	251,607,376
2028	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	59,894	32,439	31,916	351,189,056
2029	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	76,922	41,515	40,907	450,437,197
2030	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	93,639	50,299	49,703	547,885,013
2031	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	110,356	59,083	58,499	645,332,829
2032	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	127,010	67,821	67,276	742,613,700
2033	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	143,526	76,477	75,929	839,172,701
2034	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	160,005	85,109	84,550	935,511,038
2035	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	174,805	92,721	92,095	1,021,131,208
2036	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	189,587	100,322	99,622	1,106,646,686
2037	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	201,614	105,950	105,833	1,176,761,847
2038	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	213,940	111,828	112,178	1,248,528,178
2039	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	225,561	117,188	118,214	1,316,541,301

Summary of Findings

Minnesota Power has a proven track record of successful ECO performance and anticipates continuing this trend into the future, as indicated by the aggressive goals set forth in the 2024-2026 Triennial Plan and assumed in the 2025 IRP baseline forecast. However, the Company acknowledges that the current EE environment is rapidly evolving in ways that will continue to present new challenges. Changing baselines, uncertain economic conditions, evolving policy and incentives, and avoided costs will all affect Minnesota Power's ability to offer cost-effective, meaningful programs to customers. While Minnesota Power continues to build on the successes of its existing programs and adapt to challenges through unique and innovative program offerings and delivery strategies, achieving this higher level of savings through less cost-effective measures will be more resource intensive. Additionally, long-term EE savings require customers to take specific actions year after year, which introduces uncertainty regarding whether these savings will materialize. For these reasons, among others, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty. The Company has done so, while also testing what could be achieved by including alternative scenarios in its IRP analysis.

B. Part 2: Residential TOD

Time-of-Day residential rate impacts are also captured in 2025 IRP scenario planning. The Company's approved Petition for Changes to Minnesota Power's Residential Rate Design[8] included a roughly 2:1 on-peak to super off-peak price ratio, and an on-peak period lasting from 3 p.m. to 8 p.m. on weekdays, which encompasses the most common summer and winter peak times. The rate structure includes time-of-use base energy rates as well as time-of-use fuel and purchased energy adjustments. The associated rate specifications are shown in Table 8.

Table 8. Current TOD Rates ($/kWh) and Hours

	Base Energy Rate	Base Energy Rate + Fuel & Purchased Energy	Weekday Hours	Weekend Hours
Standard (Flat) Rate	$ 0.0940	$ 0.1350	N/A	N/A
On-Peak	$ 0.1307	$ 0.1800	3 pm to 8 pm	N/A
Off-Peak	$ 0.09164	$ 0.1350	5 am to 3 pm; 8 pm to 11 pm	5 am to 11 pm
Super Off-Peak	$ 0.06726	$ 0.0990	11 pm to 5 am	11 pm to 5 am

The approved transition plan consisted of a multi-phased approach to implementing and evaluating the TOD rate. Currently, the Company has completed the first phase of the transition along with an evaluation of the phase's first 12 months. While the first phase focused on operational efficiencies and customer feedback, an analysis of price response was completed as part of the evaluation. Due to the nature of the implementation during this phase, the analysis was limited. The results of this analysis are useful to begin understanding potential long-term impacts of a full roll-out of the TOD rate and were used to develop estimated impacts as part of IRP scenario planning. The Company views these impacts as preliminary and anticipates more refined estimations in the future as later phases of implementation and evaluation with more focus on price response are completed. Due to the preliminary nature of these estimates and the Company still being in the early stages of transitioning to default TOD rates, these impacts are not assumed in the base case.

As part of the February 29, 2024 compliance filing in the residential rate design docket, analysis was completed by third-party consultant Demand Side Analytics ("DSA") to estimate the observed price elasticity using the participant data from Phase I of the transition. As described in Appendix A of the compliance filing:[9]

> This analysis was conducted using a fixed effects model designed to isolate and remove static differences between customer groups, thereby focusing on variations in electricity consumption attributable to the differences in the flat rate and the TOD rate structures.
>
> Equation 3 outlines the specific model utilized estimate the price elasticity. Notably, a temperature coefficient was included to control for variation that can be attributed to

[8] *In the Matter of the Petition for Approval of Changes to Minnesota Power's Residential Rate Design,* Docket No. E-015/M-20-850, Petition (Dec. 1, 2020).
[9] *In the Matter of the Petition for Approval of Minnesota Power's Residential Rate* Design, Docket No. E-015/M-20-850, Compliance Filing at Appendix A at 24 (Feb. 29, 2024).

weather. The customers included in this model were those on the TOD rate and the new customers on the flat rate, starting service after the start of Phase I.

Equation 3 - Price Elasticity Model

$$\ln(kWh_{it}) = \beta_0+\beta_1 \ln(Price_{it})+\beta_2 (TempF_{it})+\alpha_i+\gamma_t+\varepsilon i_{th}$$

Where:

$\ln(kWh_{it})$ is the logged kWh for customer i at datetime t
$\ln(Price_{it})$ is the logged price variable for customer i at datetime t
$TempF_{it}$ represents the temperature in Fahrenheit for customer i at datetime
β_0 is the intercept term.
β_1 is the coefficient for logged price. This value represents the price elasticity
β_2 is the coefficient for temperature, indicating the estimated effects of weather on the dependent variable.
α_i represents the fixed effects for each customer i, capturing unobserved characteristics that are constant over time for a specific customer, but may vary between customers.
γ_t represents the fixed effects for each datetime t, capturing time-specific effects that are constant across all customers but vary over time.
ε_{ith} is the error term for customer i at datetime t

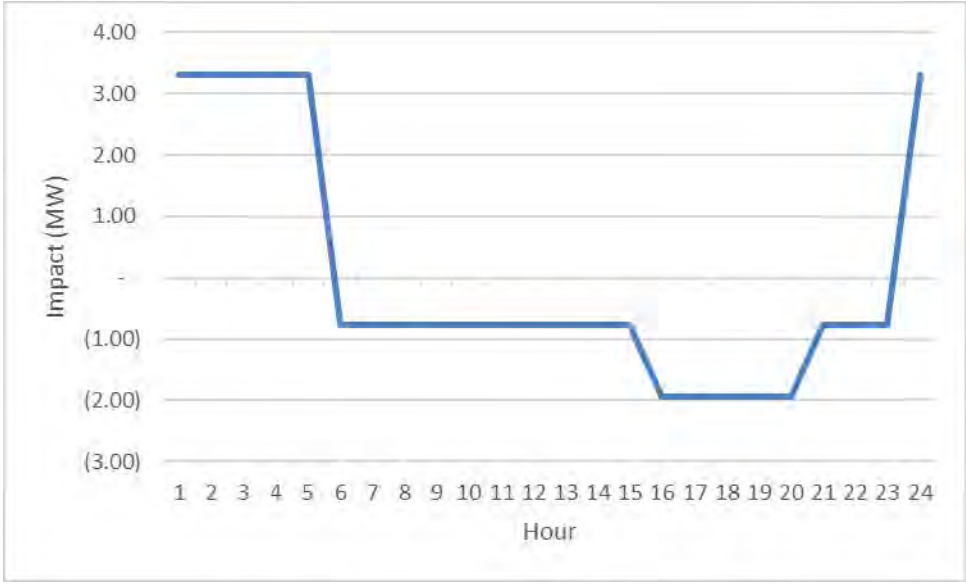
The analysis estimated that participants reduced their load during on-peak periods by 1.88 percent on average. Average impacts during off-peak periods were estimated to be a 0.66 percent reduction in usage and impacts during super off-peak periods were estimated to be a 4.5 percent increase in usage. The super off-peak impact was adjusted such that the total forecasted usage for the residential customer class was net neutral – i.e., the timing of when the usage is occurring is shifted but there is no overall decrease or increase to the forecasted load.

Table 9 below shows the percent kW impacts by TOD period. The on-peak, off-peak, and adjusted super off-peak percent impacts were applied to residential customer use profiles to create the forecasted hourly impacts associated with 100 percent residential customer participation in the TOD rate. The resulting average hourly impact shape is reflected in Figure 6 below.

Table 9. Percent kW Impact by TOD Period

Percent kW Impact			Adjusted % kW Impact
On-Peak	Off-Peak	Super Off-Peak	Super Off-Peak
-1.88%	-0.66%	4.50%	3.84%

Figure 6. Average Hourly Impacts from Residential TOD



C. Part 3: Alternative Demand Side Management

Minnesota Power has a very successful demand response program for industrial, residential, and commercial customers that plays an important role in the annual energy and capacity planning for Minnesota Power operations. Today, Minnesota Power has approximately 250 MW of interruptible demand response capability with industrial customers on its system, which is typically procured under one-year contract terms. The 2025 IRP evaluated as alternatives to supply side resources a new enhanced industrial demand response program and two demand response programs for residential and small commercial/industrial customers.

Central air conditioner ("CAC") cycling and electric hot water heater ("HW") demand response programs for residential and commercial customers were screened in the capacity expansion analysis. A demand response program that is expanded to include economic energy curtailments for industrial customers was also screened in the capacity expansion analysis.

Estimates of participation, saturation of CACs in homes and businesses, and anticipated percent of customers called on at any given time indicate a potential of 7.4 MW of capacity reduction for the CAC cycling program. This accounts for cycling the unit off for 15 minutes then on for 45 minutes which allows flexibility for CAC units to keep up with cooling demand while avoiding a post-event rebound period.

The HW program does not assume an on/off cycle during the event and instead would disconnect the HW for the duration of the event. Estimated customer participation and saturation of electric HWs indicates a potential of 4.5 MW of demand reduction.

Both programs require the installation of equipment that allows for the Company to control the CAC or HW load. The total cost of the equipment, labor, and necessary programming is estimated at $400 per participant, in 2024 dollars, based current equipment and labor rates. After this initial cost, ongoing costs include a bill incentive of $30 per participant per year for CAC cycling program customers and $60 per participant per year for HW program customers.

The utility cost of implementing these demand response programs would include, in 2024 dollars, an initial program capital expenditure of $143,000 (approximate) and annual O&M of $72,000 (approximate). This would be needed to support interface and control application software. The initial program cost and annual O&M were allocated between the CAC and HW programs based on participation.

The industrial demand response alternative modeled in the IRP expands Minnesota Power's program for industrial customers to include energy curtailment, along with emergency curtailment – it is referred to as "Product B" in the IRP analysis. This capacity is available in 2028, when the Product C demand response program subscription ends. The Product C program was approved by the Commission in 2021.[10]

Product B includes long-term capacity with economic energy curtailment. This product would offer a meaningful demand payment to customer for the opportunity to utilize their industrial capability for meeting the broader system needs. For this proxy program incorporated into the IRP evaluation there was a $7 per kW-month capacity credit and provides a $30 per MWh energy credit for curtailed energy. These parameters would be refined further when an actual tariff is brought forward with customers.

D. Part 4: Distributed Generation

The 2025 IRP includes assumptions for residential and commercial/industrial adoption of distributed solar generation, these assumptions are what comprises the "Base Case." The forecast methodology for distributed solar adoption and a resulting decrease in Minnesota Power sales are described below for both the Base Case and a Scenario which assumes a more aggressive adoption of distributed generation.

New DG solar installations were projected using the U.S. Energy Information Administration's forecast for distributed solar generation. This outlook for the number of new installs is combined with assumptions for the sizing (kW capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for new installations (i.e., installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company's Base Case forecast assumes about 4,220 new small-scale DG solar installations, adding almost 44,000 kW of nameplate capacity, will be connected to the Minnesota Power grid by 2038 (i.e., installed in years 2024-2038). These new installations would generate about 46,000 megawatt hours ("MWh") per year and reduce sales to residential and commercial sectors by an equivalent amount. The Base Case forecast assumes cumulative capacity expands at an 11 percent compound annual growth rate ("CAGR") from 2023 to 2038.

The Company's Scenario forecast utilizes the same U.S. Energy Information Administration's DG solar generation forecast but with a doubled growth rate. This updated growth rate projects approximately 5,590 new small-scale DG solar installations which adds approximately 58,000 kW of nameplate capacity that will be connected to the Minnesota Power grid by 2038. The new installations would generate almost 61,000 MWh per year of reduced sales to residential and commercial sectors, as shown in Figure 7. The Scenario forecast assumes a 13 percent CAGR from 2023 to 2038.

[10] *In the Matter of the Petition by Minnesota Power for Approval of its Industrial Demand Response Product C Contracts*, Docket No. E015/M-21-28, Order Establishing Pilot Program (Oct. 29, 2021).

Figure 7. Distributed Solar Generation Lost Sales

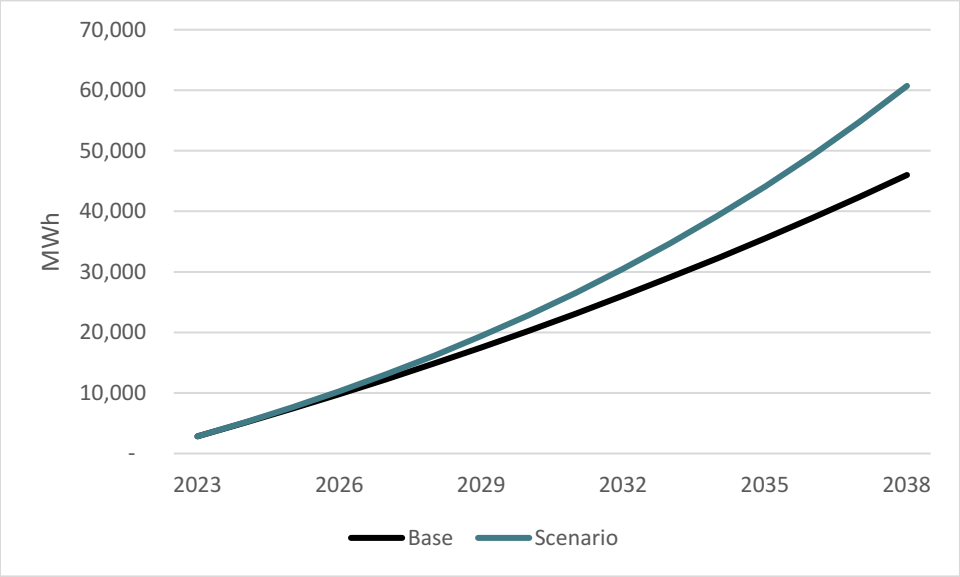
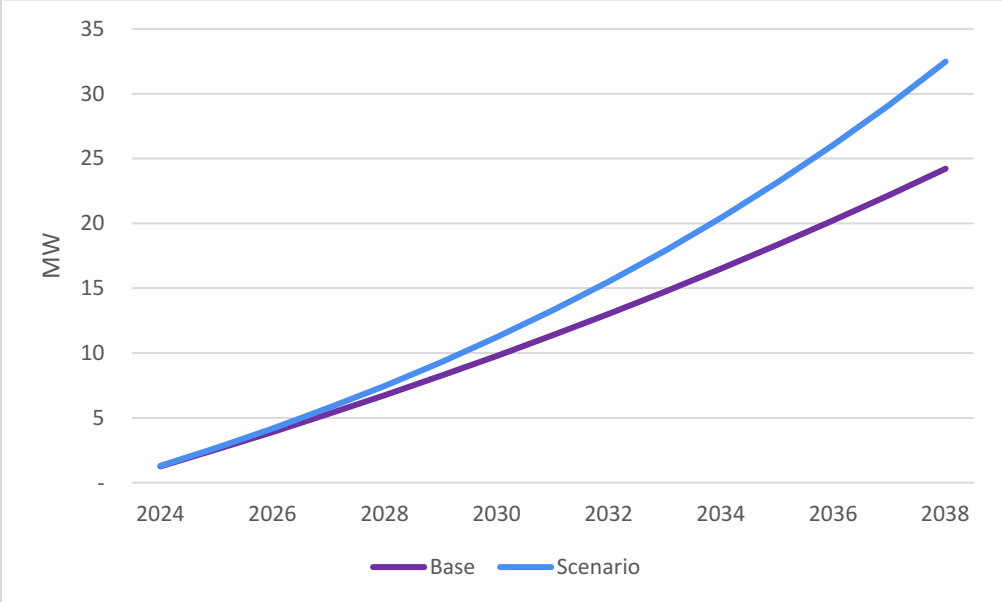


Figure 8. Distributed Solar Generation (Summer Peak)



E. Part 5: Microgrids

Microgrids provide an alternative energy solution for a clean, resilient, and reliable grid. Microgrids also interconnect loads and distributed energy resources to provide electric power when needed either connected or disconnected to the grid. Minnesota Power is exploring the benefits of microgrids, which includes pacing with customer interest. Microgrids are poised to

enhance energy sustainability and meet evolving customer demands and Minnesota Power will continue investigating the potential of microgrids on its system.

APPENDIX M

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

DRAFT VEGETATION MANAGEMENT PLAN

IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 kV TRANSMISSION LINE PROJECT

Minnesota Power and American Transmission Company, LLC

Docket Nos. E015/CN-25-111 and E015/TL-25-112

VEGETATION MANAGEMENT PLAN

DRAFT

Prepared by:

merjent

Revised: **December 2025**

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY 1

2.0 VMP OVERVIEW 1

3.0 VMP GOALS 2

4.0 SITE DESCRIPTION 2
4.1 PROJECT DESCRIPTION 2
4.2 EXISTING CONDITIONS 5
4.3 SENSITIVE ECOLOGICAL AREAS 5

5.0 PROJECT COMPONENTS 6
5.1 TRANSMISSION LINE RIGHT-OF-WAY 6
5.2 SUBSTATIONS 6
5.3 TEMPORARY CONSTRUCTION AREAS 6

6.0 RIGHT-OF-WAY PREPARATION AND CONSTRUCTION 6
6.1 LANDOWNER NOTIFICATION 6
6.2 INITIAL RIGHT-OF-WAY CLEARING 7
6.3 EROSION AND SEDIMENT CONTROL BMPS 8
6.4 RIGHT-OF-WAY PREPARATION AND CONSTRUCTION AT PUBLIC WATER CROSSINGS 8

7.0 RESTORATION 9
7.1 OVERVIEW OF RESTORATION PROCESS 9
7.2 TEMPORARY RESTORATION 10
7.3 PERMANENT RESTORATION 11

8.0 SEEDING 11
8.1 PREPARATION 11
8.2 SEED MIXES 11
8.2.1 Roadsides and Turf: Non-Native Seed Mixes 12
8.2.2 Native Seed Mixes 13
8.3 SEEDING METHODS 13
8.4 TIMING 14

9.0 HERBICIDES 14

10.0 NOXIOUS WEEDS AND INVASIVE SPECIES 15

11.0 MONITORING 16

12.0 OPERATION AND MAINTENANCE 17
12.1 ROUTINE INSPECTIONS 17
12.2 ROUTINE MAINTENANCE 17
12.3 WIRE/BORDER ZONE 17
12.4 EMERGENCIES 18

LIST OF FIGURES

Figure 1. Project Map.....4
Figure 2. Wire/Border Zone.....18

LIST OF TABLES

Table 1. Default Seed Mixes.....12

LIST OF ABBREVIATIONS AND ACRONYMS

ac	acre
AMA	Aquatic Management Area
Application	Combined Certificate of Notice and Route Permit Application
ATC	American Transmission Company, LLC
BMP	Best Management Practice
BWSR	Minnesota Board of Soil and Water Resources
Commission	Minnesota Public Utilities Commission
EA	Environmental Assessment
GIS	Geographic Information System
HVDC	High-Voltage Direct Current
ISA	Iron Range – St. Louis County – Arrowhead Project
kV	Kilovolt
lbs	Pounds
MBS	Minnesota Biological Survey
MnDNR	Minnesota Department of Natural Resources
MnDOT	Minnesota Department of Transportation
MPCA	Minnesota Pollution Control Agency
NERC	North American Electric Reliability Corporation
NOT	Notice of Termination
NPC	Native Plant Communities
NPDES	National Pollutant Discharge Elimination System
NWIS	Noxious Weeds and Invasive Species
PWI	Protected Waters Inventory
SDS	State Disposal System
SNA	Scientific Natural Area
SWPPP	Stormwater Pollution Prevention Plan
VMP	Vegetation Management Plan
WMA	Wildlife Management Area

1.0 EXECUTIVE SUMMARY

Minnesota Power and American Transmission Company, LLC by and through its corporate manager ATC Management Inc. ("ATC") (collectively, the "Applicants") are submitting to the Minnesota Public Utilities Commission ("Commission") a combined application for a Certificate of Need and Route Permit ("Application") to construct the Iron Range – St. Louis County – Arrowhead 345 kilovolt ("kV") Transmission Project (the "Project" or "ISA Project"). The Project is needed to support the reliability of the regional transmission system, particularly in northern Minnesota and northwest Wisconsin to provide additional transmission capacity and regional transfer capability to reliably integrate new renewable generation, meet growing electrical demand, and to strengthen the regional transmission grid.

The Applicants propose a route that is located along, and in some cases replaces, existing high-voltage transmission lines for 92 percent of its length. By locating the Project next to existing high-voltage transmission lines and other existing rights-of-way or replacing existing high-voltage transmission line rights-of-way, the Project can leverage existing corridors rather than creating new ones. As described in the Application, replacing and locating the Project along existing transmission line rights-of-way minimizes the potential impact of the Project within the Project Route. Based on this use of existing high-voltage transmission line rights-of-way, the Project is eligible for the Standard Review Process for the route permit. Minn. Stat. § 216I.07, subd. 2(5).

This Vegetation Management Plan ("VMP") relies on the information found in the Application for the ISA Project and the Environmental Assessment ("EA") (Appendix E to the Application).

2.0 VMP OVERVIEW

The Applicants have developed this VMP for the Project to comply with an anticipated condition in the future Route Permit, which typically requires the following:

> The Permittee must develop a Vegetation Management Plan in coordination with the Energy Infrastructure Permitting group and the Minnesota Department of Natural Resources ("MnDNR"). The vegetation management plan and documentation of the coordination efforts between the permittees and the coordinating agencies must be filed at least 14 days prior to the plan and profile. The Vegetation Management Plan must recognize landowner preferences and include the following:
>
> - Short- and long-term management objectives, including beneficial practices for pollinators.
>
> - A description of planned restoration and vegetation activities, including how the route will be prepared, timing of activities, and how seeding will occur (broadcast, drilling, etc.), and the types of seed mixes to be used.
>
> - A description of how the route will be monitored and evaluated to meet management objectives.
>
> - A description of management tools used to maintain vegetation (e.g., mowing, spot spraying, hand removal, fire, grazing, etc.), including timing/frequency of maintenance activity.

- Identification, monitoring and management of noxious weeds and invasive species (native and non-native) on site.

- Plan showing how the route will be revegetated and corresponding seed mixes. Seed mixes, seeding rates, and cover crops should follow best management practices.

3.0 VMP GOALS

The primary goals of this VMP are to:

- Construct the Project and maintain the Project right-of-way in a manner that ensures safe and reliable transmission lines and associated terminal infrastructure. Objectives are to reflect vegetation management practices that are consistent with applicable North American Electric Reliability Corporation ("NERC") requirements, as well as requirements set by the Commission, and to incorporate, where applicable, the Minnesota Public Utilities Energy Infrastructure Permitting Group's Generic Vegetation Establishment and Management Plan Guidance.

- Develop and maintain cooperative relationships with landowners along the right-of-way to accommodate reasonable requests and preferences related to right-of-way vegetation management including agriculture. Objectives are to manage vegetation to meet Applicants' and landowner goals, when possible, which means that restoration is likely to be consistent with historic vegetation and use, where practicable and consistent with safe and reliable transmission line operation.

- Comply with applicable requirements in federal, state, and local permits, licenses, and/or easements. Refer to Chapter 8 of the Application for a list of permits and approvals that may be required for the Project.

- Establish perennial vegetation throughout the right-of-way. Design seed mixes appropriate for this region and expected conditions. Prepare an establishment plan that minimizes the duration and extent of bare soil to ensure soil stability.

- Establish vegetation that will be compatible with the Project operations and minimize maintenance needs. This includes low maintenance vegetation that reduces the need for trimming and develops robust cover that minimizes potential invasion from undesirable species and management methods that minimize widespread herbicide applications and treatments to reduce vegetation height and thatch accumulation.

- Minimize invasive species, noxious weeds, and other undesirable species within the right-of-way. This includes planning for long-term monitoring and maintenance that will reduce new infestations and rapidly control species that become established.

4.0 SITE DESCRIPTION

4.1 PROJECT DESCRIPTION

See Chapter 2 of the Application for the detailed Project Description. The Applicants propose to construct a new, approximately 67.5-mile-long, double-circuit 345 kV transmission line with one circuit energized from Minnesota Power's Iron Range Substation in Itasca County, Minnesota to

Minnesota Power's St. Louis County Substation in St. Louis County, Minnesota, and a new, approximately one-mile long, double circuit 345 kV transmission line from Minnesota Power's St. Louis County Substation to ATC's Arrowhead Substation in St. Louis County, Minnesota. The Project consists of three major segments.

1. Segment 1 – Construct Approximately 32.7 miles of new single-circuit 345 kV line on double-circuit capable structures (three conductor and two shield wires), to be built along existing high-voltage transmission line rights-of-way owned by Minnesota Power from the existing Minnesota Power Iron Range Substation and continuing to north of the St. Louis River in St. Louis County. The proposed transmission line will be co-located for 87 percent of its length with existing high-voltage transmission lines owned by Minnesota Power (detailed maps in Appendix G).

2. Segment 2 – Replace approximately 33.3 miles of existing 230 kV line with new double-circuit structures and conductor capable of operating at 345 kV from north of the St. Louis River in St. Louis County to the existing St. Louis County Substation in Solway Township, utilizing and modestly expanding the existing high-voltage transmission line rights-of-way owned by Minnesota Power. One circuit in this segment will be operated at 345 kV and the other circuit will continue to operate at 230 kV.

3. Segment 3 – Construct approximately 1.5 miles of new double circuit 345 kV transmission line that is co-located for 50 percent of its length, jointly owned by Minnesota Power and ATC, from Minnesota Power's St. Louis County Substation in Solway Township to the existing ATC Arrowhead Substation in Hermantown.

The Project will also involve the following improvements:

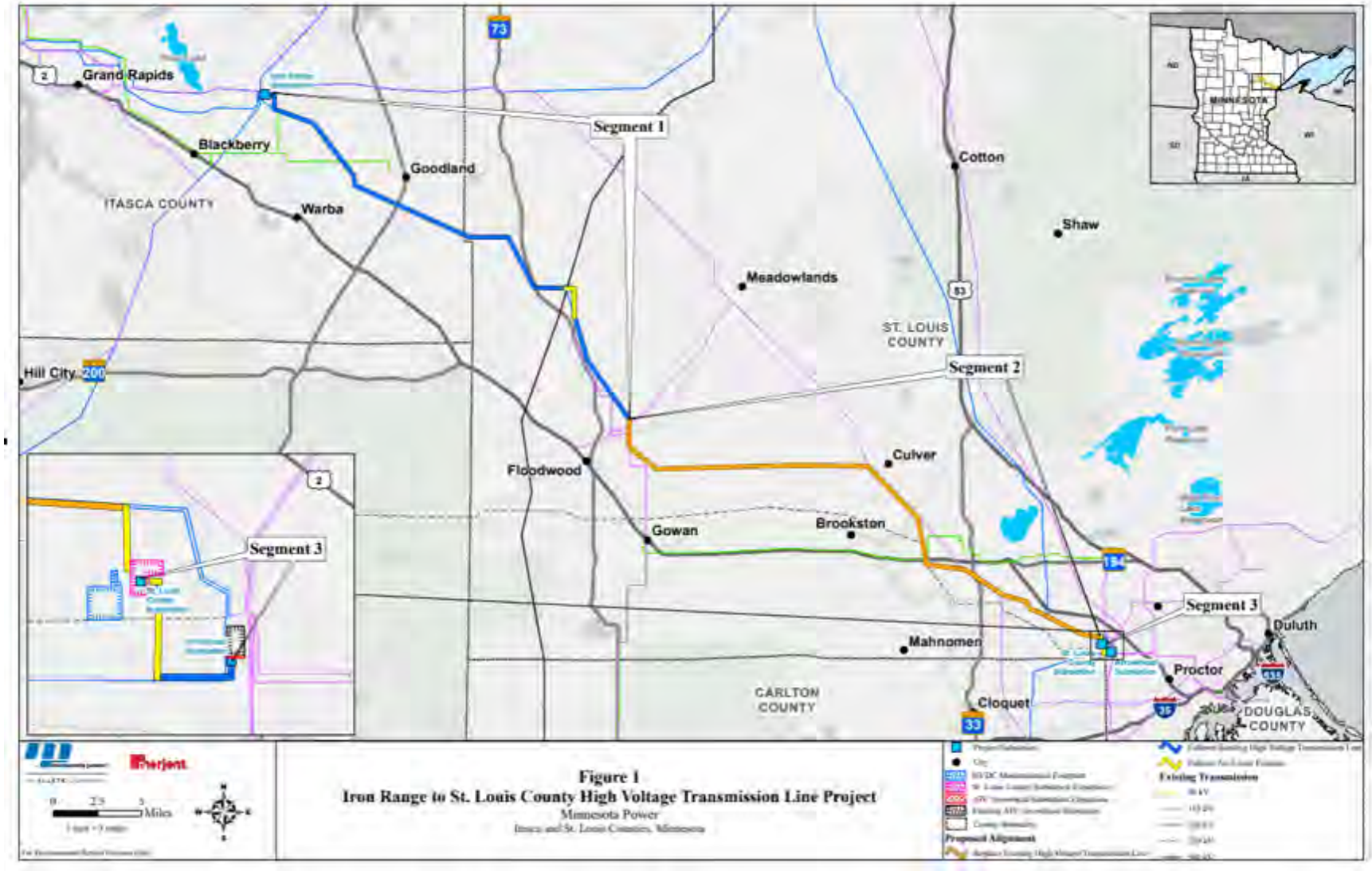
1. Modification of the Iron Range Substation to accommodate one additional 345 kV line entrance and associated high-voltage equipment. An expansion of Minnesota Power's Iron Range Substation, including 500/345 kV transformers and 345 kV equipment, is currently under construction as part of the Northland Reliability Project (Docket Nos. E015,ET2/CN-22-416 and E015,ET2/TL-22-415) and will require further modification and equipment additions to accommodate the ISA Project.

2. Expansion of the St. Louis County Substation to accommodate three additional 345 kV line entrances and associated high-voltage equipment. The St. Louis County Substation is currently under construction as part of Minnesota Power's HVDC Modernization Project (Docket No. E015/TL-22-611) and will require an expansion to accommodate the ISA Project.

3. Expansion of the existing ATC Arrowhead Substation to accommodate two additional 345 kV line entrances and associated high-voltage equipment.

The Project is shown in Figure 1. Additional maps can be found in Appendix G of the Application.

Figure 1. Project Map



4.2 EXISTING CONDITIONS

Vegetation communities in the Proposed Route[1] include agricultural land, forest (deciduous, mixed, evergreen), wetlands, transmission line rights-of-way, and residential areas. The Project Study Area lies within the Laurentian Mixed Forest Province as defined by the Ecological Classification System of Minnesota, and more specifically within the North Shore Highlands, Tamarack Lowlands, and St. Louis Moraines Subsections. The Proposed Route generally moves from the northwest to the southeast with elevations ranging from approximately 1,241 to 1,397 feet above mean sea level.

Detailed information on existing conditions, including land use, land cover, soils, topography, water resources, flora and fauna, can be found in the EA prepared by Merjent, Inc. ("Merjent") and the Application submitted by Minnesota Power and ATC (Docket Nos. E015/CN-25-111 and E015/TL-25-112). During construction and maintenance of the Project, the Applicants and their contractors will rely on the most recent Geographic Information System ("GIS") mapping to identify relevant resources such as wetlands and sensitive and rare resources. Project maps are included in the EA and in the Application. The Applicants will obtain a Utility Crossing License for any crossings of Public Water Inventory ("PWI") waters and for any crossings of public lands.

4.3 SENSITIVE ECOLOGICAL AREAS

There are no MnDNR Wildlife Management Areas ("WMA") or MnDNR Scientific and Natural Areas ("SNA") in the Proposed Route. The Proposed Route and Proposed Right-of-Way cross Minnesota Biological Survey ("MBS") Sites of Biodiversity Significance and Native Plant Communities ("NPC"). See Section 2.6.8 of the EA for more information on Rare and Unique Natural Resources.

The MBS has identified 11 mapped Sites of Biodiversity Significance (Table 39, EA) within or adjacent to the Proposed Route. This includes three that are ranked High and one ranked Outstanding along the route. Sites of Biodiversity Significance have varying levels of native biodiversity and are ranked based on the relative significance of this biodiversity at a statewide level. Factors considered during the ranking process include the number of rare species documented within the site, the quality of the native plant communities in the site, the size of the site, and the context of the site within the landscape.

The Proposed Route includes or is adjacent to eight mapped native plant communities (Table 40, EA, nearly all are within MBS Sites), including three native plant community classes/types that are or may be rare (Conservation Status Rank of S1 through S3).

To protect and minimize disturbances to these Outstanding and High sensitive ecological areas on MnDNR land, the Applicants will work with the MnDNR to avoid or minimize impacts on areas of Biological Significance and will use sediment and erosion control best management practices ("BMPs") for all biologically significant areas crossed by the Project. See Section 2.1.6 of the EA for a discussion of impacts and mitigation for WMAs, Aquatic Management Areas ("AMA"), and State Forests within the Proposed Route.

[1] The Proposed Route is described in detail in Chapter 2 of the Application.

5.0 PROJECT COMPONENTS

Refer to Chapter 6 of the Application for more details.

5.1 TRANSMISSION LINE RIGHT-OF-WAY

The Applicants' and their representatives will work directly with individual landowners to acquire the necessary easements and other land rights for the construction, operation, and maintenance of the Project once the final route is approved and the preferred alignment is determined. Minnesota Power owns the land on which the Project substations are located. The Project requires a 150-foot-wide right-of-way (75 feet on each side of the centerline). However, to the extent practicable, the new single circuit 345 kV transmission line on double circuit capable structures in Segment 1 will be co-located with existing high-voltage transmission lines, thereby facilitating the partial sharing of right-of-way and lessening the amount of new right-of-way required from landowners for the Project. To ensure safe construction of the Project, the Applicants will clear the right-of-way of woody vegetation in advance of construction.

5.2 SUBSTATIONS

No new substations are anticipated to be constructed as part of the Project. Instead, the Project will connect the existing Minnesota Power Iron Range Substation, Minnesota Power St. Louis County Substation, and ATC Arrowhead Substation. Detailed explanations of the work to be performed at each of Minnesota Power's Iron Range Substation, Minnesota Power's St. Louis County Substation, and ATC's Arrowhead Substation are provided in Section 2.1.5 of the Application.

5.3 TEMPORARY CONSTRUCTION AREAS

Temporary construction areas can include wire stringing areas, off right-of-way access routes, and laydown yards. These areas are used for material storage, right-of-way access, and equipment access to support construction activities. Landowner easements may be acquired for these stringing areas. The location of any temporary construction areas will be identified in the Project design plans as well as the Project Stormwater Pollution Prevention Plan ("SWPPP").

6.0 RIGHT-OF-WAY PREPARATION AND CONSTRUCTION

Detailed descriptions of the Applicants' right-of-way preparation and construction methods are included in Chapter 6 of the Application.

6.1 LANDOWNER NOTIFICATION

Landowners will be notified prior to clearing activities, as required by applicable permit conditions (typically 14 days). Among other things, the notification letter will inform landowners:

- The right-of-way will be staked indicating the extent of clearing activities.
- Landowners can request to keep any of the trees and materials. Requested wood will be cut to no less than 8-foot segments. Requested whole trees, trunks, wood chips or mulch will be placed just outside of the right-of-way.
- All unwanted woody materials will be removed from the landowner's property.

- Landowners within the Project right-of-way will be notified if herbicides will be used on their property. The notice will indicate what herbicides will be used and the methods of application (e.g., broadcast, selective spot treatment, or basal treatment). If a landowner prohibits their use, herbicides will not be used on that landowner's property. See Section 9.0.

6.2 INITIAL RIGHT-OF-WAY CLEARING

See Section 6.2 of the Application for Construction Procedures.

Construction will begin once all necessary federal, state, and local approvals are received, land rights are secured, and the final design is complete. The exact timing and duration will also depend on permit requirements, system demands, and workforce availability. The initial phase of constructing new transmission structures entails surveying the centerline, easement boundaries, and pole locations, followed by the removal of all trees and vegetation within the designated rights-of-way. In areas where the project aligns with existing rights-of-way, overlapping rights-of-way may reduce the need for additional clearing, thereby minimizing vegetation clearing and environmental impact. The right-of-way will be surveyed and marked in advance of tree clearing to identify the extent of Project activities. Staging and laydown areas will be limited to previously disturbed areas where practicable and will avoid wetlands.

Prior to site clearing and vegetation removal activities, erosion and sediment control measures will be installed in accordance with any municipal stormwater permits and the Minnesota Pollution Control ("MPCA") National Pollutant Discharge Elimination System ("NPDES") Construction Stormwater Permit. Vegetation clearing will be limited to the permanent right-of-way, temporary right-of-way, danger trees off right-of-way, and off-right-of-way access. BMPs will be used to minimize the spread of invasive/noxious weeds. See Section 10 of this VMP.

All trees will be cleared during the northern long-eared bat inactive season (November 14 to April 1). Mechanical equipment such as feller bunchers or brush cutters may be used for clearing. In areas where clearing with large equipment is not viable, clearing will be done with hand tools such as chain saws. Where trees are removed subject to state or federal permits, appropriate licenses/permits will be obtained and followed.

Vegetation within the right-of-way will be cut at or slightly above the ground surface. Any tree stumps or surface roots in managed turf grasses will be ground to slightly below grade and the hole backfilled with dirt and seeded with a similar turf grass mixture. Any stumps outside of managed turf grass areas will typically be cut or ground such that no more than two inches remain above grade. The Applicants do not typically grub stumps or roots to minimize soil impacts and erosion potential.

Trees, trunks, and/or limbs cut on private property are typically cut to approximately 8-foot lengths unless the landowner requests longer lengths.

Trees (>4 inches diameter at breast height ("dbh") or >20 feet tall) cut from a wetland will be moved outside of the wetland. If the materials are chipped or shredded, that work will be completed outside of wetlands. Brush within a wetland may be cut with a brush mower or similar device as long as the chips/mulch will not exceed four inches in depth. If sufficient brush is present such that debris will exceed 4 inches, sufficient brush will be hauled out for processing in an upland area.

All material resulting from the clearing operations will be managed in accordance with agreements made with the property owner during easement negotiations. Options include chipping the material on-site and spreading it within the right-of-way, stacking it for use by the property owner, or removing it for proper disposal.

6.3 EROSION AND SEDIMENT CONTROL BMPS

All work will comply with the SWPPP developed as part of the Project NPDES permit. The SWPPP will define BMPs for erosion and sedimentation prevention and mitigation. Excavating in steeply sloped areas will be avoided to the extent practicable. Due to entanglement issues with small animals, use of erosion control blanket shall be limited to 'bio-netting' or 'natural netting' types and specifically not products containing plastic mesh netting or other plastic components.

The SWPPP will include a site-specific plan detailing where erosion and sediment controls will be implemented throughout the Project. These controls may include silt fencing, straw wattles, vegetative buffers, and other measures, as deemed necessary by the certified SWPPP preparer. Per MPCA requirements, a certified SWPPP inspector will inspect the Project once every seven days and within 24 hours after a rainfall event greater than 1/2 inch in 24 hours (see Section 11 of this VMP for more detail). The purpose of the inspections will be to monitor the effectiveness of BMPs and to identify any corrective actions needed to maintain permit compliance.

6.4 RIGHT-OF-WAY PREPARATION AND CONSTRUCTION AT PUBLIC WATER CROSSINGS

See Section 2.6.4 in the EA for a complete discussion of Public Waters Impacts and Mitigations. Public waters are wetlands, water basins, and watercourses of significant recreational or natural resource value in Minnesota as defined by Minn. Stat. § 103G.005. The Proposed Alignment crosses 23 water resources that are part of the MnDNR Public Waters Inventory ("PWI"), which includes the six rivers (West Branch Floodwood, Floodwood, St. Louis River, Cloquet River, White Pine River, and Artichoke River) and two jurisdictional ditches (S-002-034-006 and S-002-034-009). Joula Creek is crossed twice. Eight streams crossed by the Proposed Alignment are designated trout streams as per Minn. R. Ch. 6264. The Proposed Route also crosses two Public Water Basins (Andy Lake and a public water wetland).

Measures will be implemented throughout the Project to avoid and minimize direct impacts on lakes, rivers, and streams, including public waters and trout streams, and to maintain and protect water quality. As a result, impacts on surface water resources will be minimal as the condition and function of the resource will not be considerably altered by the proposed Project. By design, a majority of the Project is co-located (approximately 97 percent) with existing transmission lines, which avoids new habitat fragmentation. The Applicants will design the spans to place structures outside of lakes, rivers, and streams.

Applicants will also implement BMPs as described in the Project's SWPPP prior to, during, and following construction to reduce the potential for sediment to reach surface waters, including public waters and trout streams, and to maintain water quality. Materials such as fuels, lubricants, paints, and solvents required for construction would be stored away from surface water resources according to appropriate regulatory standards. Any spills or leaks would be cleaned up immediately and leaking equipment removed from the area for proper maintenance in accordance with the approved SWPPP.

Although most surface water resources will be avoided, construction of the Project may require temporary bridges across some waterways, including public waters. Equipment bridges will be designed to meet the requirements of the MnDNR and other applicable permitting authorities, including the U.S. Army Corps of Engineers to meet requirements of Section 404 and Section 10 where applicable. Installed bridges will be removed as soon as possible during final restoration once the bridge is no longer required to complete and monitor restoration activities.

Through the license approval process, the Applicants and the MnDNR will determine the appropriate stipulations for public water crossings, which may include in-water work exclusion dates and clearing setbacks. In locations where clearing activities may take place near public waters, a stream bank buffer may be established or hand clearing techniques may be used to minimize impacts on soils and existing vegetation. Rootstock of woody vegetation will remain in place to avoid impacts on soils and allow existing vegetation to regrow more quickly.

The Applicants will span the designated trout streams and will work with the MnDNR to avoid impacts by following in-water exclusion dates. Through the NPDES permitting process the Project will be required to comply with Section 23.1 of MNR100001, which includes designated trout streams within the definition of special waters. Several BMPs are required conditions of the permit and include items such as redundant perimeter controls, the stabilization of exposed soils immediately upon completion of work, and establishment of a 100-foot buffer to be implemented to minimize erosion near MnDNR designated trout streams.

7.0 RESTORATION

See Section 6.3 of the Application for Restoration Procedures.

7.1 OVERVIEW OF RESTORATION PROCESS

Once construction ceases, the right-of-way will be inspected to identify areas impacted by Project activities. Typical impacts might include rutting, soil compaction, soil exposure, and damage to native vegetation, all to varying degrees. Areas of minimal disturbance will be allowed to regenerate naturally. Such areas may include those where erosion is limited to dispersed areas and surrounding existing vegetation provides control of sediments; existing vegetation is matted down due to vehicle traffic; or areas where drilling spoils are raked into existing vegetation. These areas will be identified at the time of restoration.

All conditions specified in local, state, and federal permits and private landowner agreements for final restoration and cleanup will be met. Revegetation and restoration of disturbed areas associated with Project activities (which will be detailed in the Project SWPPP) are intended to protect wetland and water resources from issues associated with sedimentation, to protect wildlife habitat, and reduce the movement of Noxious Weeds and Invasive Species (“NWIS”) within the right-of-way.

Restoration activities may, as needed, include:

- Collection and disposal of all work-related debris and trash.
- Discing or grading to repair rutting.
- Regrading areas disturbed by construction or clearing to reflect pre-construction topography.

- Returning floodplains to pre-construction profile if disturbed during construction.

- Applying temporary cover and/or temporary seed to minimize erosion potential to the extent practicable.

- Permanent seeding of non-agricultural areas disturbed by transmission line structures or other facilities and the installation of temporary stabilization, following the SWPPP (see Section 6.3), to prevent runoff.

- Post-construction restoration efforts in agricultural lands could include restoration of any temporary access modifications and deep plowing to remove compaction, if needed.

- Unless timber, slash, or chips have been requested by the landowner, all residual vegetation materials will be removed and properly disposed of off-site. The Applicants may request a burning permit from state or local jurisdictions to burn residuals.

- Temporary access routes, if any, may be left intact with landowner agreement unless otherwise restricted by federal, state, or local regulations. If a temporary access road is to be removed, the land will be returned to its previous use and restored to pre-construction conditions to the extent practicable unless the landowner requests otherwise.

- Within wetlands, all construction matting will be removed, and vegetation will be allowed to regenerate naturally. Seeding may be used if required for adequate restoration.

7.2 TEMPORARY RESTORATION

Temporary cover and/or seeding may be used as a quick means to minimize soil erosion and reduce the potential for the establishment of NWIS. Temporary seed mixes are considered a cover crop and are made up of annual grasses, have rapid germination, and provide quick ground cover. These seed mixes are not intended to provide multi-year cover. Unless specifically requested by landowners or regulatory agencies, the Project will not establish temporary vegetation on cultivated land or in areas of open water.

Temporary vegetation must be placed in accordance with the SWPPP. Temporary restoration activities will include the repair of rutted surfaces and an even broadcast-seeding of the temporary cover-crop seed mix at a rate of 100 lbs./acre. Temporary vegetation establishment may be expected to be successful between April 1 and September 30. Establishment of temporary vegetation is unlikely to be successful outside of this time window. Temporary use of mulch to stabilize soils may be applied outside of the April 1 through September 30 window.

Straw or wood chip mulch may be used to help stabilize areas of bare soils during the establishment of temporary vegetation or during the period between October 1 and April 1 (winter). See Section 10 of this VMP for more details on weed-free mulch. Mulch in wetland areas cannot exceed 1 inch thick. The contractor will apply mulch during the establishment of temporary vegetation as requested by the landowner or specified in licenses or permits. Wood chip mulch free of soil material and derived from on-site sources may be used to protect areas where bare soils have been exposed due to tree clearing and construction activities. In winter situations, wood chips may be used to protect bare soils exposed due to Project activities if out of season seeding is not applicable. Wood chip mulch derived from on-site locations may be spread up to 6 inches deep in upland areas to provide ground protection along access paths. Straw mulch may be used outside of the seeding window as a temporary erosion control measure, followed by temporary or

permanent seeding at the earliest possible time consistent with specific seed mix planting guidelines.

7.3 PERMANENT RESTORATION

Allowing for and encouraging native species to naturally re-establish temporarily disturbed areas is a primary BMP for this Project. Appropriate vegetative cover of the right-of-way will be required along the entire length of the Project, apart from permanent terminal facilities. In most cases natural revegetation by early successional native species following tree clearing and construction is expected to occur. In areas where native species revegetate the corridor, active restoration may not be required.

Where standing water is not present, and where surrounding vegetation is dominated by abundant native species, the seeding of bare soils, using the temporary cover-crop seed mix may be sufficient for cover while native species revegetate the area. The Applicants may consult with the appropriate agencies during the construction period to assess application of techniques in specific locations. Permanent seed mixes for the Project may include native seed varieties commonly found and/or available from local seed distributors. The permanent seed mixes are designed to augment the natural colonization of bare ground by local, native seed sources. Potential seed mixes are identified in Section 8.2 of this VMP.

In wetlands, the preferred method for revegetation of disturbed areas is reliance on revegetation by resident plant communities. The Applicants, in consultation with the appropriate regulatory agencies and/or landowners, will determine whether disturbed areas will require the use of the temporary cover crop only, or seeding with a wetland-specific mix. In areas where the wetland plant community is dominated by native species with rhizomatous root systems that will likely recolonize areas of limited disturbance, bare soils are to be broadcast-seeded with the seasonally appropriate temporary cover-crop seed mix. Large bare soil disturbance areas are defined as greater than 100 square feet of exposed soils that is greater than 2 feet wide. These areas are large enough to preclude revegetation from the local, native seed source. Large bare soil areas should be seeded using wetland seed mix.

8.0 SEEDING

8.1 PREPARATION

Seedbed preparation and seeding are to occur following completion of construction activities and site cleanup, and after possible NWIS control, in any given location and consistent with seasonal conditions (e.g., snow cover or frozen ground may preclude effective grading and seeding). Where construction activities have resulted in erosion or rutting, surface grade will be restored prior to seeding.

To minimize ground disturbance along the entire corridor, forested areas will be cleared, but roots and stumps will be left in place. Fertilizers and other soil amendments are not recommended and will only be applied as requested by and agreed to in right-of-way negotiations with individual landowners.

8.2 SEED MIXES

The following restoration areas and vegetation types are present in and adjacent to the right-of-way:

- Turf grasses
- Pasture/unmanaged lands
- Road right-of-way
- Forest

Seed mixes are based on regionally appropriate state seed mixes that are recommended by the Minnesota Board of Soil and Water Resources ("BWSR")[2] and Minnesota Department of Transportation ("MnDOT").[3] The mixes are listed in Table 1. The table includes two non-native seed mixes that are formulated for pastures or lawn found in the MnDOT 2024 Seed Mix Guide. The identified seed mixes are examples of suitable mixes for each site, and replacements are likely to be needed based on availability at the time of construction. Seed mixes were not selected for wetland areas, because it is expected that these areas would regenerate naturally. If re-seeding is required in wetlands, those wetlands will be individually assessed to determine the appropriate seed mix.

Table 1. Default Seed Mixes

Seeding Area	Seed Mix Name (State Seed Code)	Rate (Pure Live Seed ["PLS"])
Private turf	Northern Boulevard ("NB")	150 lbs./ac.
Private pastures and hay fields	Sandy Inslope ("SI") or landowner preference	65 lbs./ac.
Natural vegetation: Shaded	Woodland Edge Northeast (36-312)	32 lbs./ac.*
Natural vegetation: Riparian	Riparian NE (34-362)	30 lbs./ac.*
Natural vegetation: Stormwater	Stormwater Northeast (33-361)	39 lbs./ac.*
Wetlands	No seed mix provided. These areas are expected to revegetate naturally.	
* Cover crop is included in these seed mixes lbs Pounds ac Acre		

8.2.1 Roadsides and Turf: Non-Native Seed Mixes

The recommended seed mixes will meet the variety of conditions along the right-of-way. There are two seed mixes that are composed of non-native species.

1. **Sandy Inslope (SI)** was selected for the areas that are part of the site access areas not under the transmission lines and along access road(s). This mix will be suitable for dry sandy areas, but it will also do well in areas with more moderate soil moisture.

[2] "Seed Mixes," Minnesota Board of Water and Soil Resources, accessed September 2025, https://bwsr.state.mn.us/seed-mixes.

[3] "Erosion Control and Stormwater Management," Minnesota Department of Transportation, accessed September 2025, https://www.dot.state.mn.us/environment/erosion/vegetation.html.

2. **Northern Boulevard (NB)** was selected for areas that are manicured and mown as part of lawns.

8.2.2 Native Seed Mixes

Native seed mixes were selected to meet the expected variety of conditions present along the right-of-way. If sufficient seeds are not available at the time of seeding, a similar, appropriate seed mix will be used. The three mixes are relatively diverse, with grasses, rushes, and forbs:

1. **Woodland Edge Northeast (36-312)** for partly shaded grassland planting for native roadsides, reclamation, etc. in north-central and northeast Minnesota. This is mapped for areas where tree clearing will be expected. However, it should be limited to areas that will receive 50 percent or more shading from nearby trees after the trees have been removed. Seed mixes are dependent on the year-to-year harvest, but can include up to:

    a. 8 grass species
    b. 13 forb species

2. **Riparian NE (34-362)** for riparian areas along rivers, streams, and other waterbodies in northeast Minnesota with areas of moist soils and potential flooding during part of the growing season and full to partial sun where land is being converted from other uses such as agriculture or non-native grasses to riparian plants. Seed mixes are dependent on the year-to-year harvest, but can include up to:

    a. 8 grass species
    b. 10 sedge and rush species
    c. 21 forb species

3. **Stormwater Northeast (33-361)** for use in areas for the management of stormwater runoff from impervious surfaces and along stormwater pond edges, temporarily flooded dry ponds, and temporarily flooded ditch bottoms. This mix may be used to manage stormwater runoff from the proposed non-transmission facilities. Seed mixes are dependent on the year-to-year harvest, but can include up to:

    a. 6 grass species
    b. 4 sedge and rush species
    c. 10 forb species

One of the optional mixes that is not included in the summary table is the Native Construction (32-242) mix, which is lower diversity and generally lower cost than the others selected. This mix can be used in a variety of soil moistures and in full or nearly full sunlight conditions. It is not recommended because of the greater diversity in the preferred mixes but may be a useful back-up seed mix for use in some circumstances.

8.3 SEEDING METHODS

Broadcast seeding may be used in all disturbed areas where bare soil is created. Broadcast seeding will occur as specified in the seed mixes. Seed is to be uniformly distributed by a mechanical, hand-operated seeder, or in small seeding areas, by hand. Following seeding, the surface is to be raked with a cultipacker, harrow, or hand rake. The bed is to be firmed as appropriate to site conditions.

Hydroseeding may be used in all disturbed upland areas where bare soil is created. Hydroseeding is not approved in wetland locations as the method requires extra access by heavy vehicles. Hydroseeding will occur as specified in the seed mixes. Seed will be applied in a broadcast, hydromulch slurry. The hydromulch seed mix will allow the contractor to see where application has taken place, ensuring uniform coverage of the seeding area. The hydroseeder must provide for continuous agitation of slurry and provide for a uniform flow of slurry. Hydroseed slurry is not to be held in the tank for more than one hour prior to application. The Applicants will only use hydromulch products approved by MnDOT.[4]

Seed drilling may be used in areas where stumps have been removed and a prepared seed bed can be created. However, these areas are expected to be infrequent and may not occur on the Project. Drilled seed will be sown at an appropriate depth based on the type of seed. Seeding equipment will be able to accommodate and uniformly distribute different sizes of seed at the required depth. Feeding mechanisms will be able to evenly distribute different seed types at the rates specified. Seedbed soil is to be suitably firmed immediately following seed drilling.

8.4 TIMING

Forb-dominated pollinator seed mixes can be installed in the spring or fall but fall dormant plantings allow seeds to naturally stratify and settle into the soil through periods of freezing and thawing over the winter. Spring seedings should be done on or around May 1 through July 1 when soil temperatures are at least 60 degrees Fahrenheit or higher. Fall seeding should occur when soil temperatures fall below 50 degrees Fahrenheit for a consistent period of time (usually around October 15 in the northern half of the state). Fall dormant seedings can help reduce weed pressure during the first year of growth because native cool-season grasses and forbs germinate earlier and start competing with weed species right away (BWSR seed mix recommendation). Outside of these time windows, temporary seed mixes, applied according to temporary cover crop (see Section 8.2 of this VMP) seed mix specifications, are to be used. Prior to installation of native seed mixes, the seedbed should be mowed and prepared for final seeding.

9.0 HERBICIDES

Landowners within the Project right-of-way, operators of organic farms on adjacent parcels, and bee apiary operators within 3 miles, if known, will be notified 14 days in advance if herbicides will be used on the right-of-way. The notice will indicate what herbicides will be used and the methods of application (e.g., broadcast, selective spot treatment, or basal treatment).

Unless a landowner has specified that no herbicides are to be used on their property, herbicides may be used to treat tree and brush stumps to prevent regrowth, and/or to control listed invasive or noxious weed species (Section 10 of this VMP). No organic farming is known to be practiced on properties within or adjacent to the Proposed Route.

Any weed control spraying will be in accordance with State of Minnesota regulations. Herbicides will be used in accordance with manufacturer's specifications and all applicable federal and state regulations. All herbicide applicators on the Project must be certified herbicide applicators.

Herbicides used within or near wetlands or waterbodies must be:

[4] "Approved/Qualified Products," Minnesota Department of Transportation, accessed September 2025, https://www.dot.state.mn.us/products/erosioncontrolandlandscaping/hydraulicerosioncontrol.html.

- designed for use in wet areas as designated by manufacturer's specifications and federal and state regulations, and

- used in accordance with manufacturer's specifications as well as all applicable federal and state regulations.

Areas of high public exposure such as rivers, creeks, streams, and U.S. and state highways shall be treated with a selective basal or backpack application. Approximately 30 to 300 feet on each side of the crossing shall be treated in this manner.

To prevent herbicide drift, herbicides will not be applied when local wind speeds exceed 10 miles per hour. Herbicides will also not be applied during rainy conditions or when soils and vegetation are water-saturated.

Herbicides will not be used on any state or federal lands without approval of the agency having authority over such land.

10.0 NOXIOUS WEEDS AND INVASIVE SPECIES

During all phases of Project activities including clearing, construction, operation, and maintenance, the Project will minimize the introduction and spread of NWIS along the right-of-way by implementing BMPs that discourage the spread of identified species (including plant species, pests, and fungi), and routine cleaning of equipment to remove dirt and plant debris. The goal is to prevent new infestations on the right-of-way as a result of construction activities. It is important to note that there may be NWIS already existing on private parcels along the right-of-way. While this does not preclude the Project from responsibility for managing the spread of invasive species, this ability may be limited by pre-existing conditions.

Plant species that are regulated as noxious weeds in Minnesota are listed by the Minnesota Department of Agriculture in its Noxious Weed list.[5] No noxious weeds have been designated by St. Louis or Itasca County.

During construction and maintenance, to prevent the spread of noxious weeds from an impacted to a non-impacted area, the Applicants will implement the following BMPs:

- Maintenance equipment will be cleaned before it is used in Project right-of-way and between equipment use in a known impacted area and a non-impacted area. Cleaning will consist of scraping or blowing to remove visible dirt and weed debris from machinery and trailers, including tracks and wheels. The contractor(s) must maintain records of cleaning for each piece of equipment used onsite. This information will be available upon request.

- Only weed-free materials (e.g., straw bales, bio-rolls, mulch) will be used in erosion control and only weed-free seed will be used during revegetation.

- Equipment and clothing will be inspected for invasive materials.

[5] "Noxious Weed List," Minnesota Department of Agriculture, accessed September 2025, https://www.mda.state.mn.us/plants-insects/minnesota-noxious-weed-list.

- Collected invasive materials will be secured and disposed of at an offsite location to avoid dispersal.

- Minimally disturbed areas will be allowed to revegetate naturally.

- Major infestation areas may be treated with the recommended herbicides (if approved by the landowner) or by mechanical methods such as mowing or burning. The contractor will be required to obtain the necessary permits and/or certifications for burning or the use of applicable herbicides.

Revegetation in non-agricultural areas will be considered successful when the cover of acceptable vegetation is dominant and non-NWIS species density is less than or similar to surrounding lands that have not been affected by the Project. If monitoring indicates a higher density of NWIS, the Project will take appropriate measures to control NWIS.

The Applicants will monitor and control NWIS within the right-of-way throughout the construction of the Project, per the requirements of the SWPPP. During Project construction, the Applicants will inspect and provide information regarding infestations of NWIS along the right-of-way to the appropriate agencies.

11.0 MONITORING

The Applicants will monitor areas, using a MPCA-required certified SWPPP inspector, where seeding and erosion control measures have been implemented and will follow up with reseeding measures where vegetative cover from seeding, or revegetation by the local, native seed source, is inadequate to provide long-term stability and sustainable native plant communities, approximately 70 percent cover. The Minnesota NPDES/State Disposal System ("SDS") permit ("General Permit") requires that for all permitted areas of disturbance, the permit may not be terminated until the project has met the definition of final stabilization and specifically;

> "Permittees must establish a uniform perennial vegetative cover (i.e., evenly distributed, without large bare areas) with a density of 70 percent of the vegetative cover native to local undisturbed areas on all areas not covered by permanent structures, or equivalent permanent stabilization measures. Permanent cover does not include temporary BMPs such as wood fiber blanket, mulch, and rolled erosion control products", and
>
> "Permanent cover means surface types that will prevent soil failure under erosive conditions (e.g., gravel, concrete, perennial cover, or other landscaped material that will permanently arrest soil erosion). Permanent cover does not include temporary BMPs such as wood fiber blanket, mulch, and rolled erosion control products."[6]

The exception is for construction projects within agricultural lands, where the agricultural land must be returned to preconstruction agricultural use (i.e., decompacted, topsoil replaced) prior to submitting the Notice of Termination ("NOT").

The Applicants will meet easement and lease conditions and obligations and will continue to work with landowners and the appropriate agencies to achieve standards set forth in easement or lease agreements during construction and subsequent maintenance activities.

[6] Minn. R. 7090. General Permit Condition 25.22.

12.0 OPERATION AND MAINTENANCE

See Section 6.4 of the Application for detailed Operation and Maintenance Procedures.

12.1 ROUTINE INSPECTIONS

In addition to the SWPPP inspections during and after active construction, the Applicants will also conduct aerial and/or ground visual inspections of the right-of-way to ensure a safe and reliable corridor and to ensure access for maintenance activities or emergencies. Maintenance work will be based on the findings of those inspections.

12.2 ROUTINE MAINTENANCE

The Applicants will periodically clear vegetation from the existing right-of-way to maintain a safe and apparent corridor, and to allow access for maintenance activities or emergencies. The clearing will be done consistent with wire/border zone practices (see Section 12.3 for more detail on wire/border zone). Clearing typically includes brushing equipment traveling down the right-of-way, which may consist of tracked or rubber-tired equipment to cut brush and trees, hand-held saws, or other manual methods. Small cuttings will be left in place, non-merchantable timber or slash will be disposed of where it originates, hauled off-site, or chipped and evenly spread on the right-of-way.

Project-specific maintenance techniques and mitigation measures include:

- If the surface is unstable such that rutting, soil compaction, or soil mixing may occur, low ground-pressure equipment will be used or maintenance equipment will be operated from weed-free mats or temporary timber corduroy that will be removed upon completion of the work.

- Steep slopes and slopes leading to water bodies will be cleared by hand, leaving adequate herbaceous or low shrub cover to avoid erosion.

- Vegetation management requirements stipulated in any MnDNR, MnDOT, or local governmental unit licenses or permits will be followed.

12.3 WIRE/BORDER ZONE

The Applicants use the wire/border zone methodology in maintaining the right-of-way, consistent with typical conditions in Minnesota Route Permits. The wire zone, or clear zone, is generally defined as the area that extends outside of the area directly below the outermost conductors of the transmission line.[7] The wire border zone concept Minnesota Power uses is based on the transmission line right-of-way divided in thirds. Low-growing woody vegetation is allowed within the border zone based on engineering specifications and safe operation of the line (Figure 2). The Applicants encourage all landowners to contact the Applicants regarding any plans to plant or construct within the right-of-way.

[7] In areas where sloped, rocky, or other complex terrain characteristics limit equipment access on one side of the transmission centerline or where the transmission line angles, the wire zone may need to be extended further out on one side of the transmission centerline.

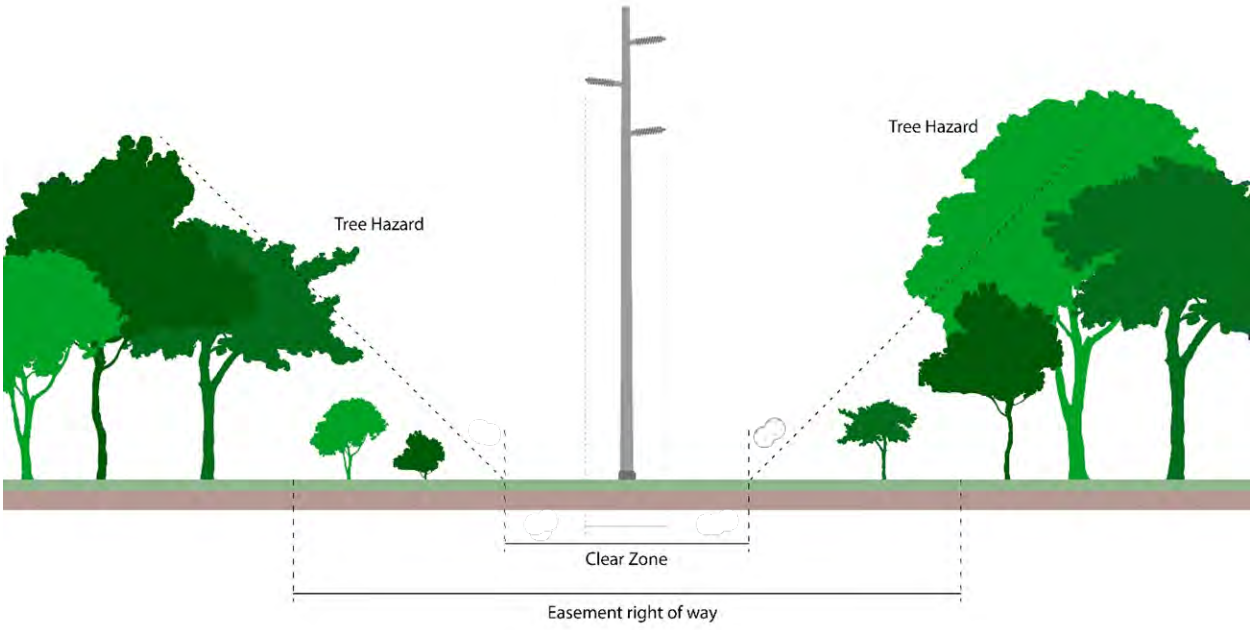
The border zone extends from the edge of the wire zone to the edge of the right-of-way.

The wire zone is maintained free of any vegetation that would inhibit the Applicants from accessing the right-of-way with its equipment or limit its ability to use equipment, such as bucket trucks, to maintain or quickly repair the transmission line. No trees or shrubs are allowed to establish within the wire zone. Stumps or roots that could impede equipment travel will be removed by cutting or grinding them at or slightly below the surface.

Trees that lie outside of the easement but have branches and/or foliage that lie within the border zone, as depicted in Figure 2, may be pruned or removed. Again, the Applicants encourage landowners to contact the Applicants regarding any planting within the right-of-way.

Danger trees are designated by a certified arborist and are typically any tree that is leaning, damaged, has poor root structure, or showing signs of internal decay such that the Applicants' right-of-way inspectors believe all or portions of the tree may fall into the transmission line. The Applicants' easements authorize the removal of danger trees outside of the right-of-way. Danger tree removal is a critical aspect of ensuring transmission line reliability and fire prevention.

Figure 2. Wire/Border Zone



12.4 EMERGENCIES

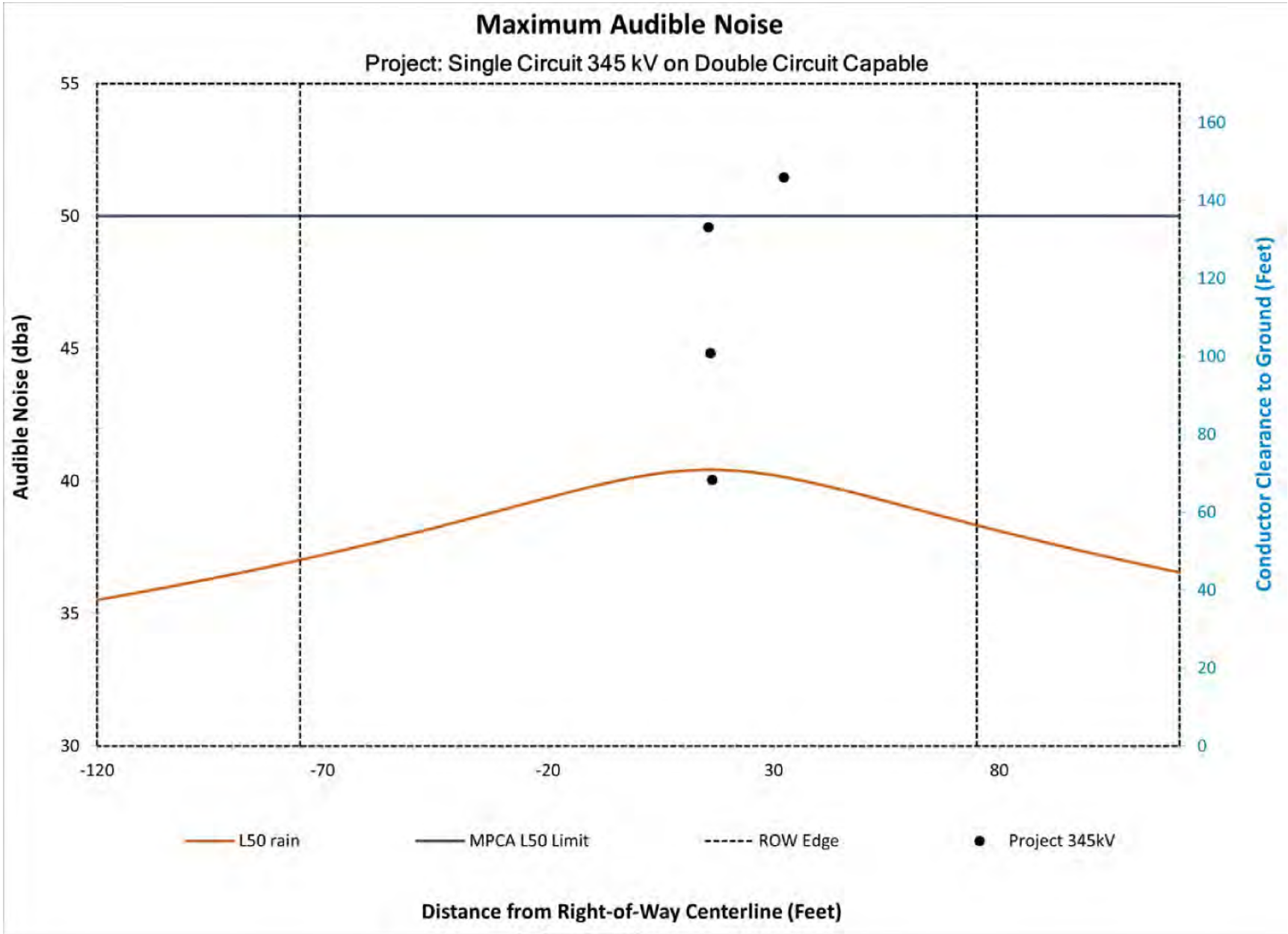
It may be necessary for the Applicants to cut, trim, or remove vegetation due to damage caused by weather events or accidents. Such work is typically done to facilitate restoring services on the line. Staff will attempt to notify the landowner prior to entering the property.

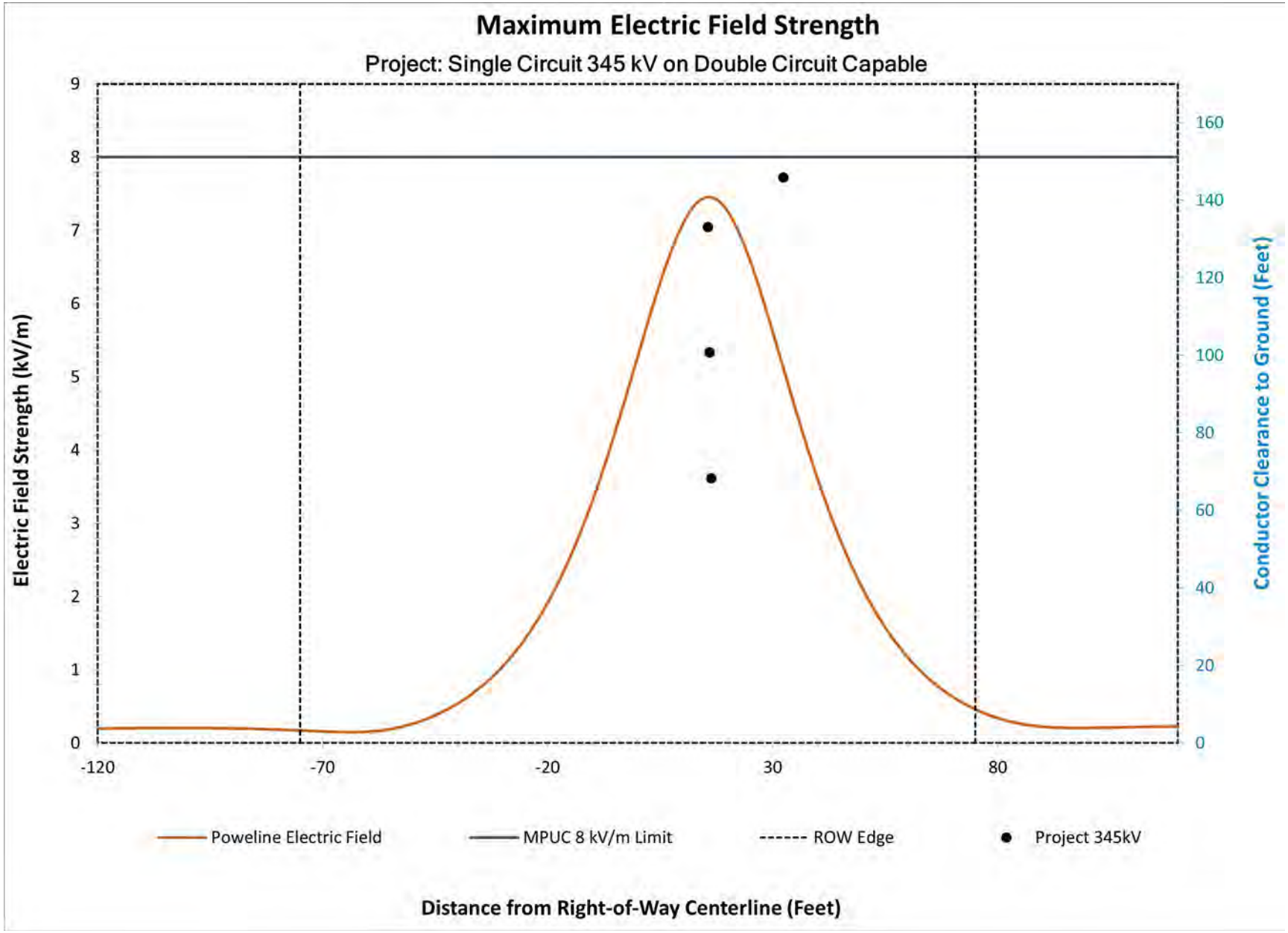
APPENDIX N

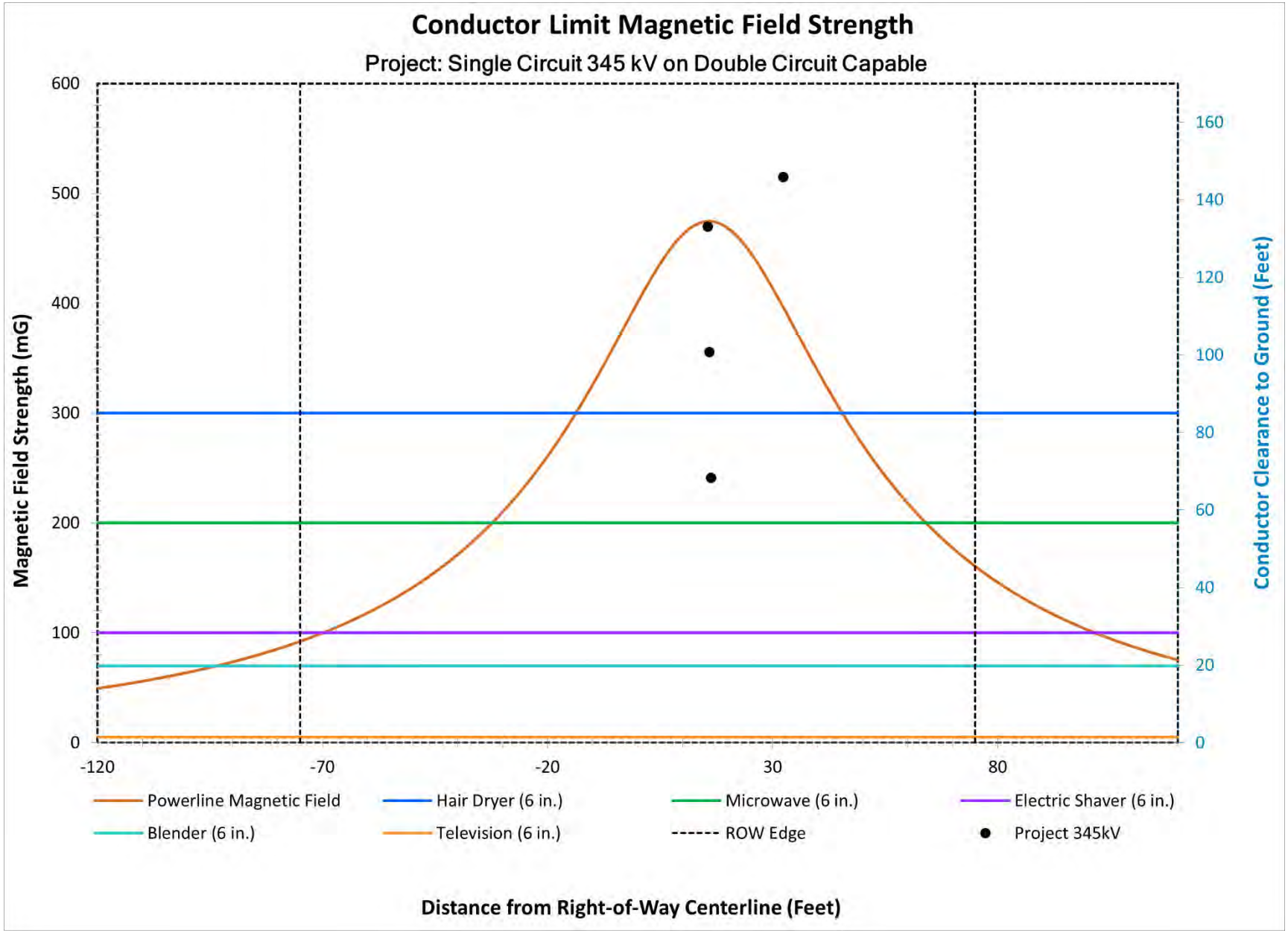
IRON RANGE – ST. LOUIS COUNTY – ARROWHEAD 345 KV TRANSMISSION LINE PROJECT

EMF AND NOISE CALCULATIONS

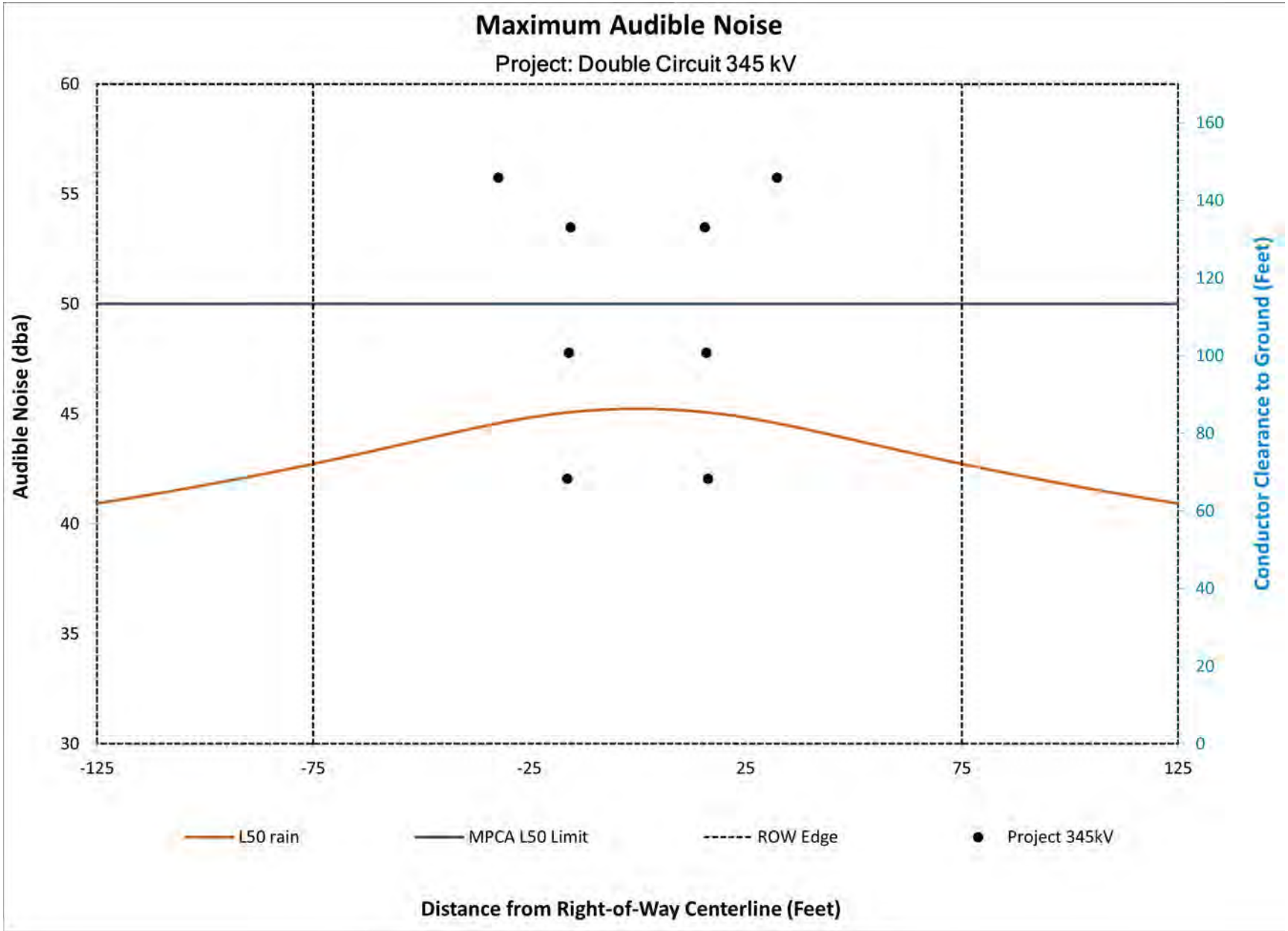
Project: Single-Circuit 345 kV on Double-Circuit Capable

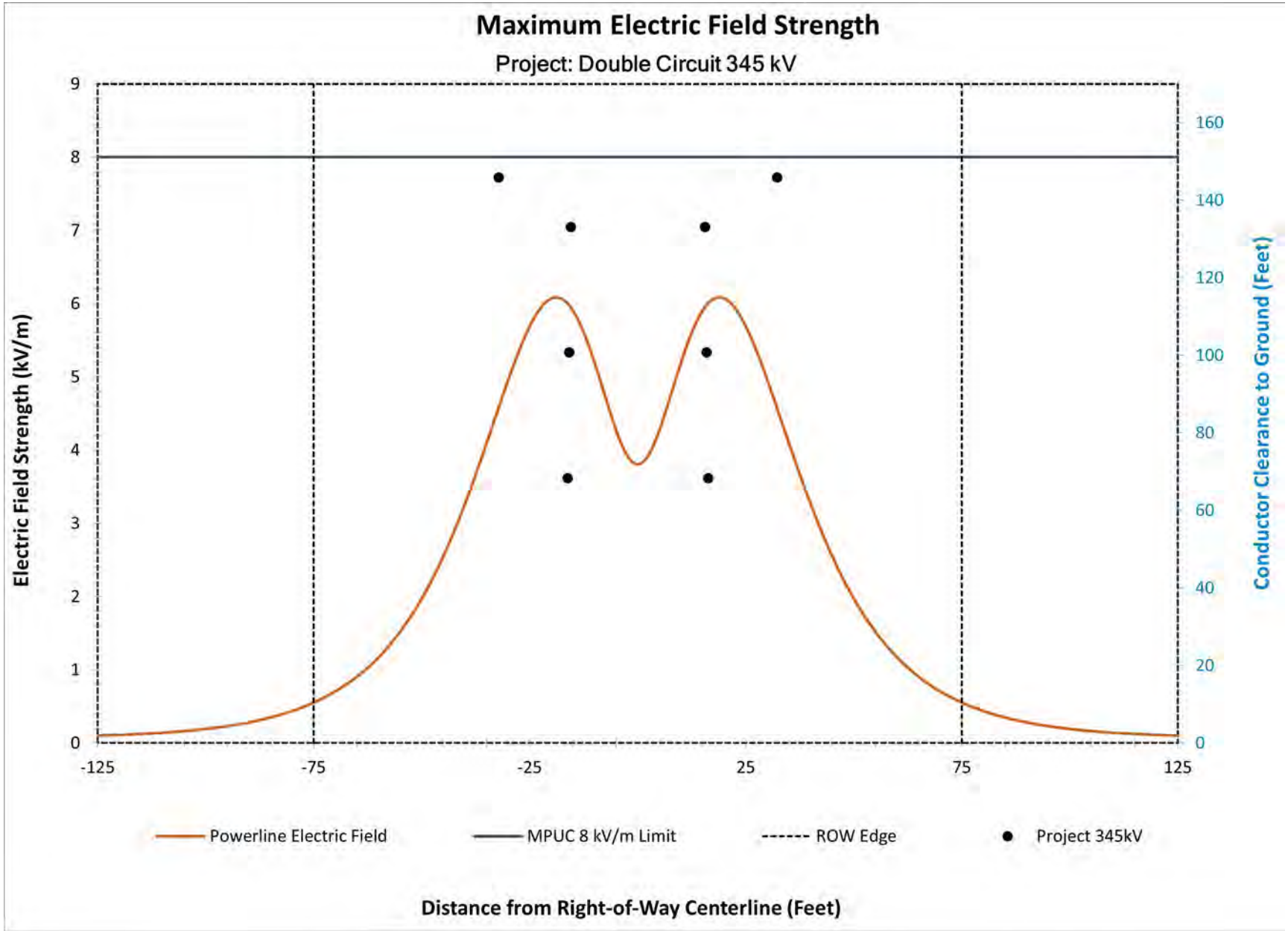


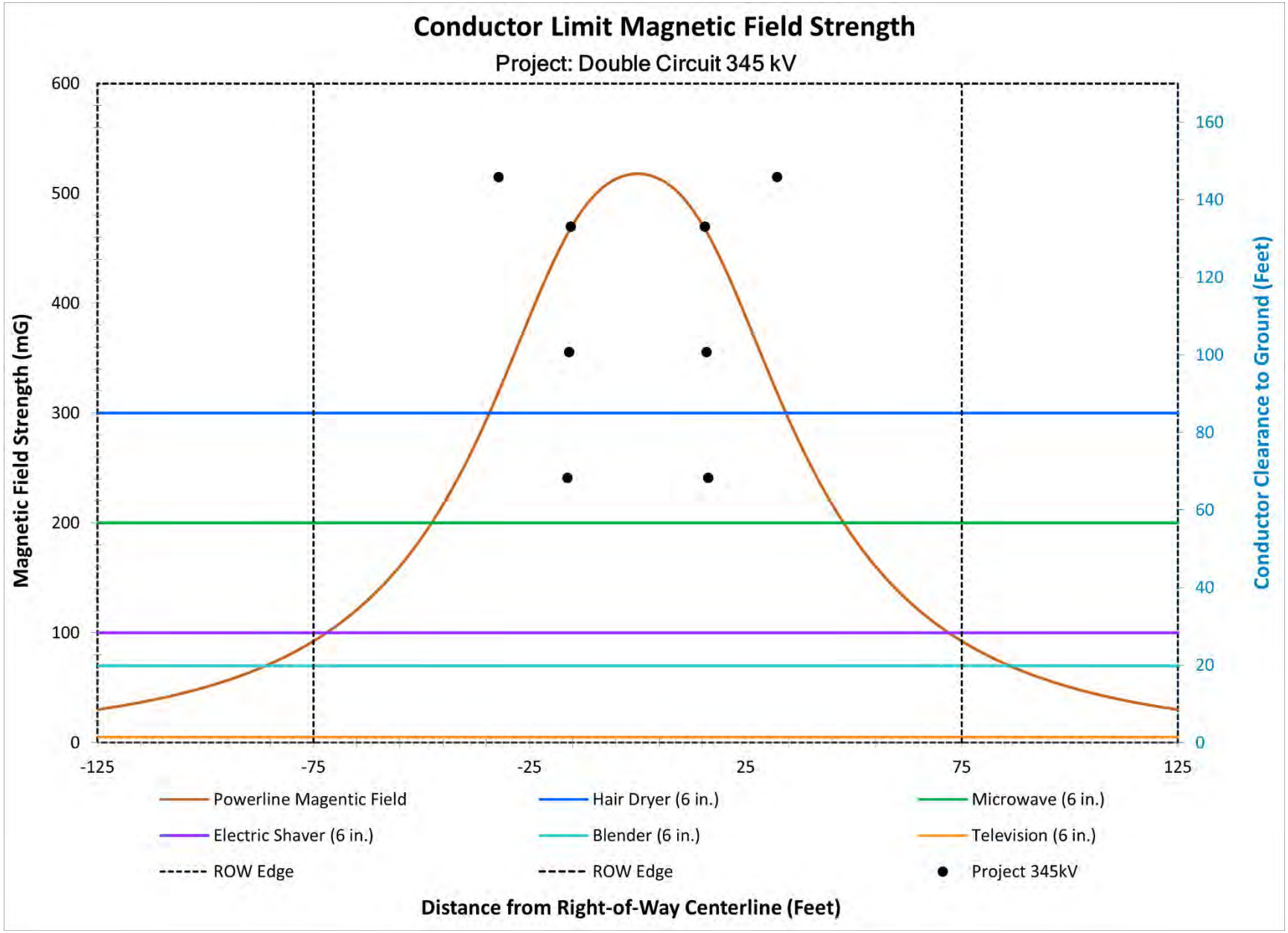

Maximum Electric Field Strength
Project: Single Circuit 345 kV on Double Circuit Capable
Electric Field Strength (kV/m)
Conductor Clearance to Ground (Feet)
0
1
2
3
4
5
6
7
8
9
0
20
40
60
80
100
120
140
160
-120
-70
-20
30
80
Poweline Electric Field
MPUC 8 kV/m Limit
ROW Edge
Project 345kV
Distance from Right-of-Way Centerline (Feet)


Conductor Limit Magnetic Field Strength
Project: Single Circuit 345 kV on Double Circuit Capable
Magnetic Field Strength (mG)
Conductor Clearance to Ground (Feet)
600
500
400
300
200
100
0
160
140
120
100
80
60
40
20
0
-120
-70
-20
30
80
Powerline Magnetic Field
Hair Dryer (6 in.)
Microwave (6 in.)
Electric Shaver (6 in.)
Blender (6 in.)
Television (6 in.)
ROW Edge
Project 345kV
Distance from Right-of-Way Centerline (Feet)

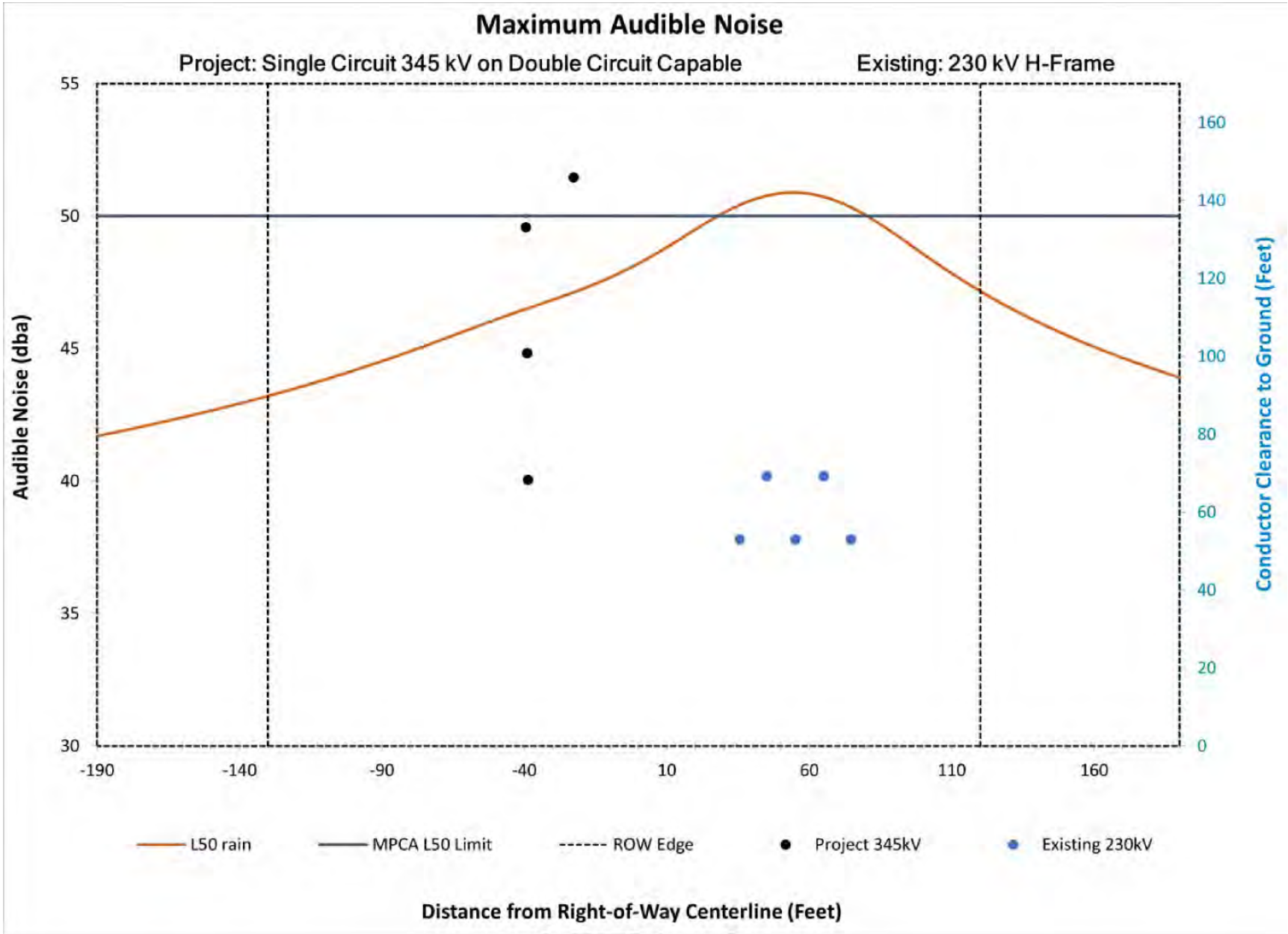
Project: Double-Circuit 345 kV



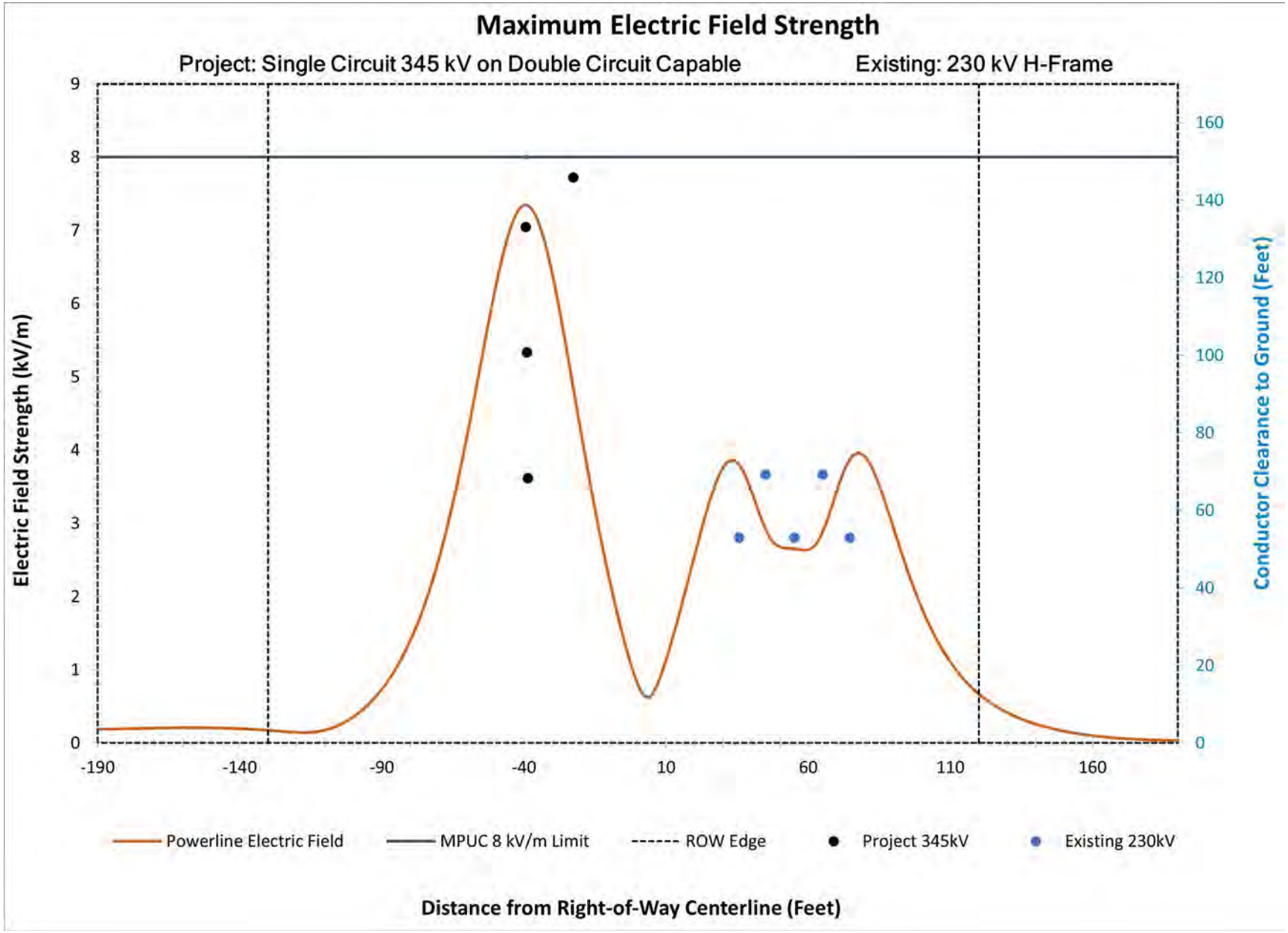

Maximum Electric Field Strength
Project: Double Circuit 345 kV
Electric Field Strength (kV/m)
Conductor Clearance to Ground (Feet)
0
1
2
3
4
5
6
7
8
9
0
20
40
60
80
100
120
140
160
-125
-75
-25
25
75
125
Powerline Electric Field
MPUC 8 kV/m Limit
ROW Edge
Project 345kV
Distance from Right-of-Way Centerline (Feet)


Conductor Limit Magnetic Field Strength
Project: Double Circuit 345 kV
Magnetic Field Strength (mG)
Conductor Clearance to Ground (Feet)
600
500
400
300
200
100
0
160
140
120
100
80
60
40
20
0
-125
-75
-25
25
75
125
Powerline Magentic Field
Hair Dryer (6 in.)
Microwave (6 in.)
Electric Shaver (6 in.)
Blender (6 in.)
Television (6 in.)
ROW Edge
ROW Edge
Project 345kV
Distance from Right-of-Way Centerline (Feet)

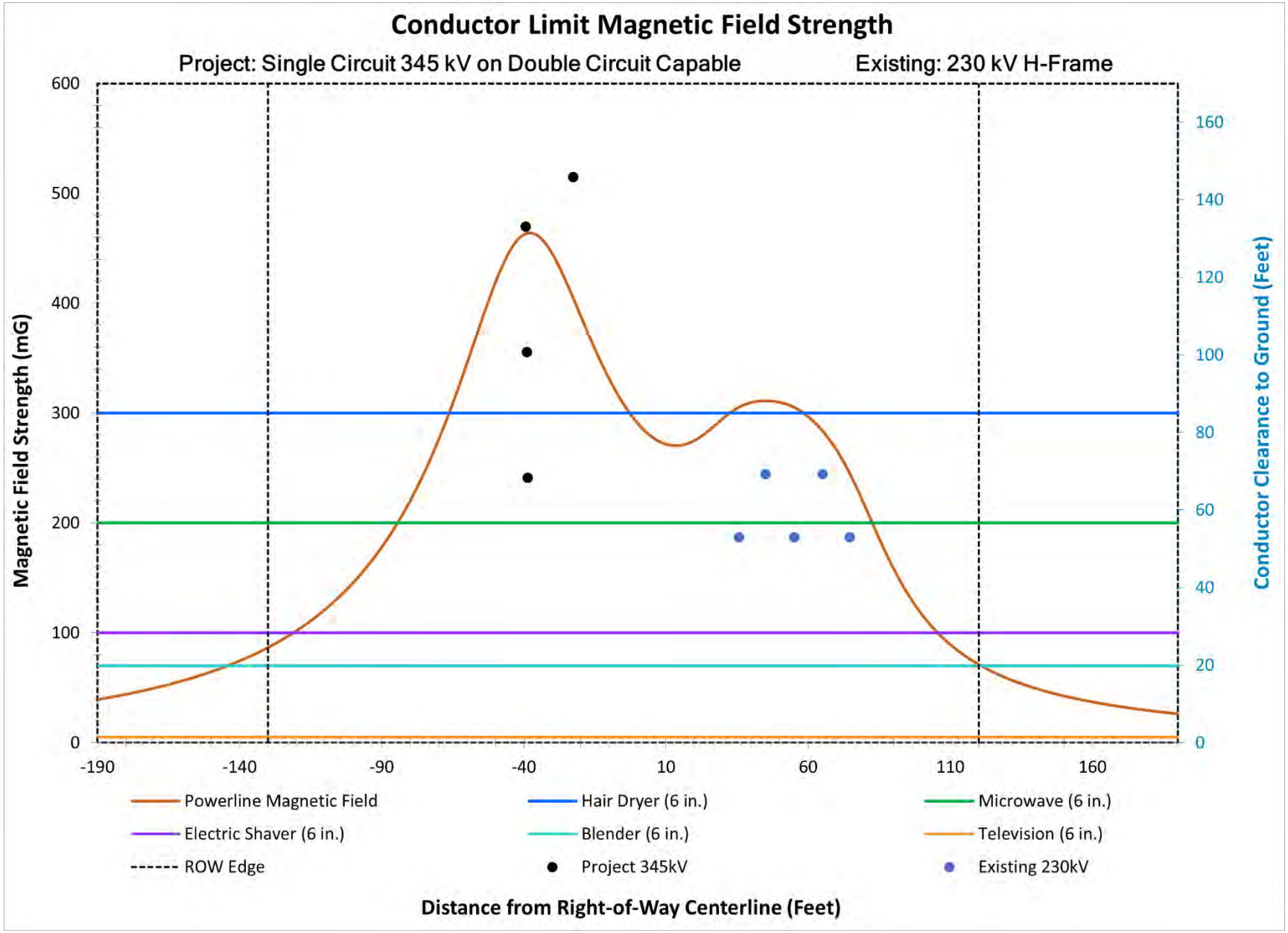
Project: Single-Circuit 345 kV on Double-Circuit Capable
Existing: 230 kV H-frame

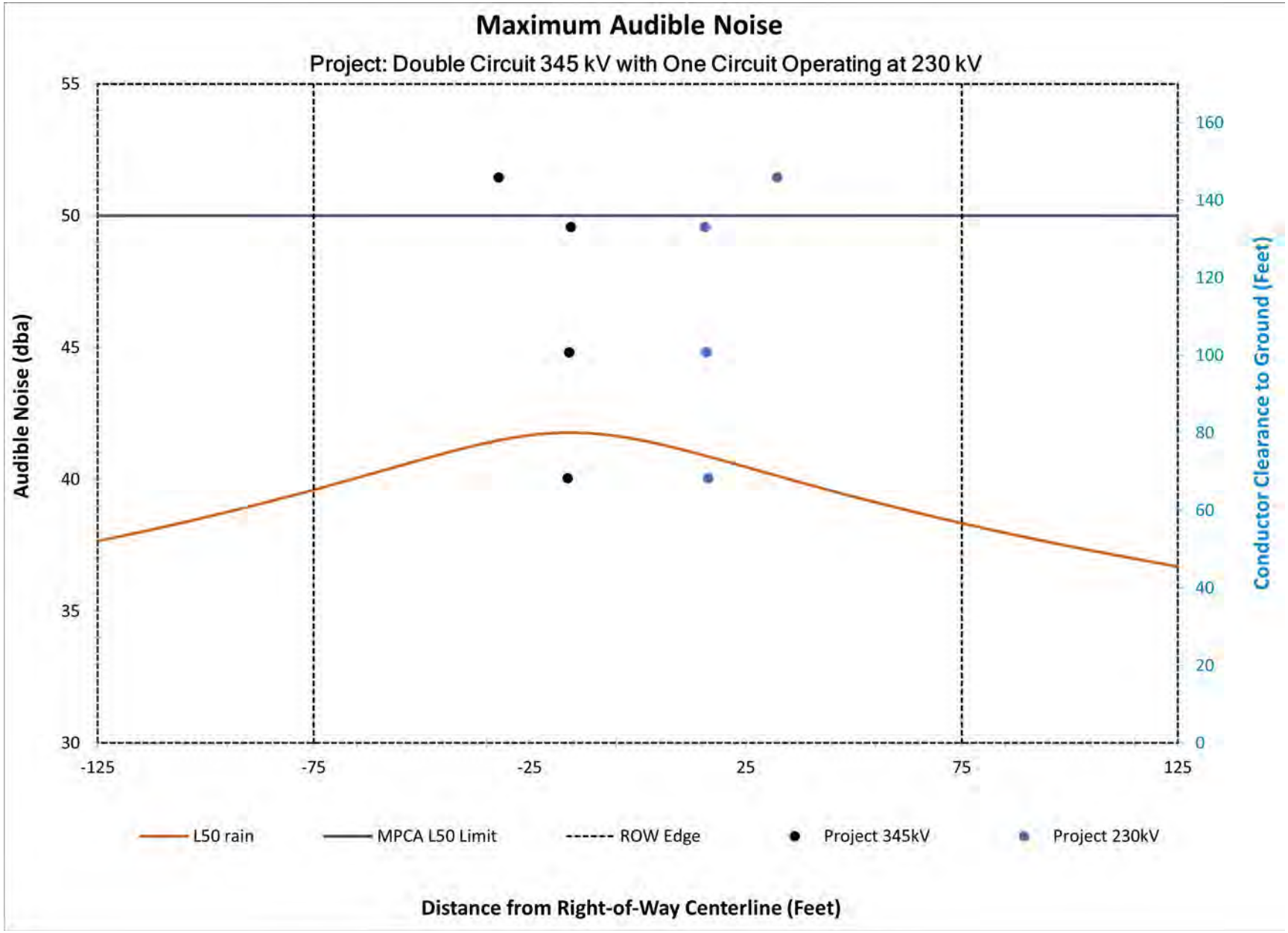


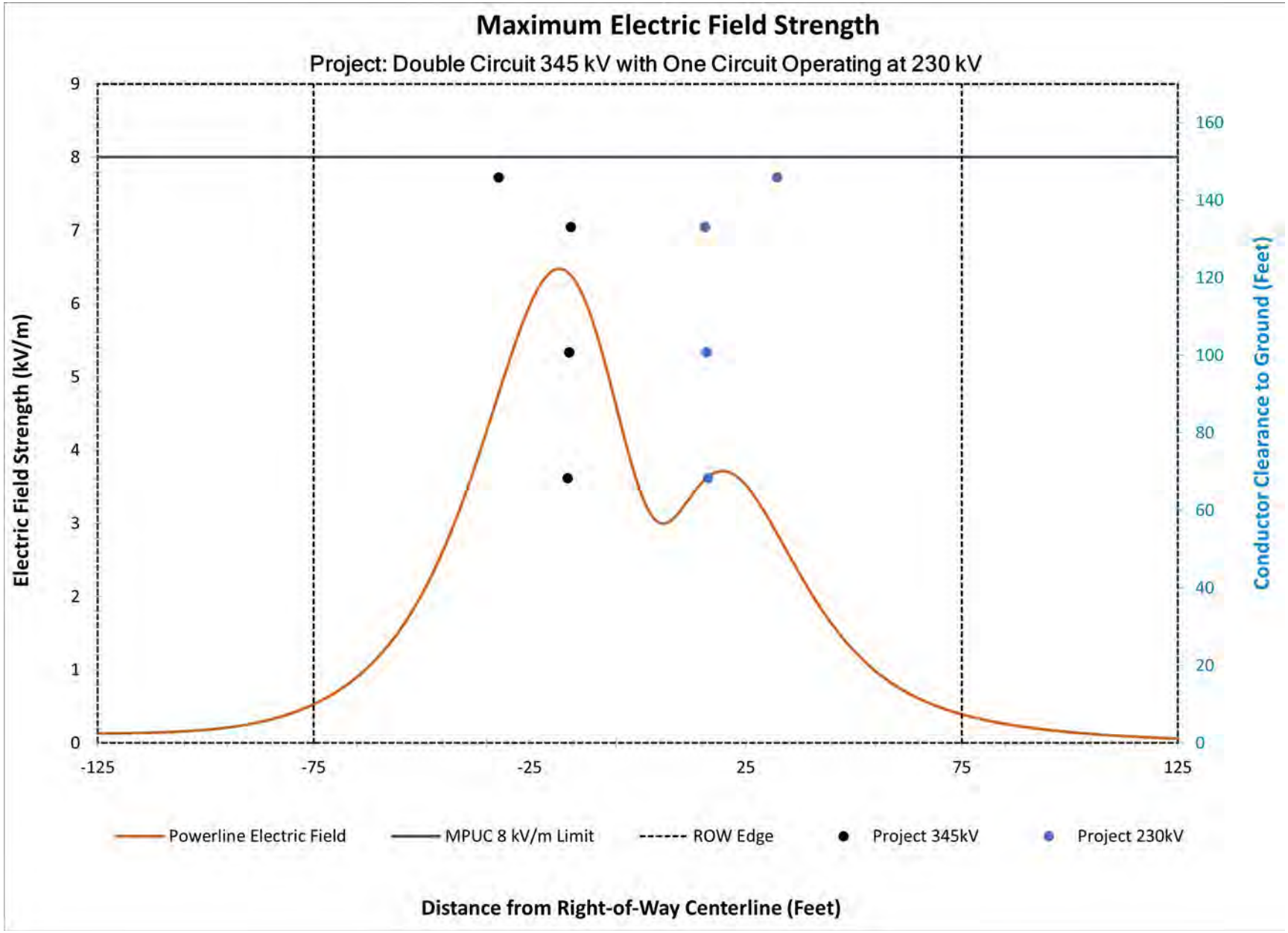
Project: Single-Circuit 345 kV on Double-Circuit Capable
Existing: 230 kV H-frame

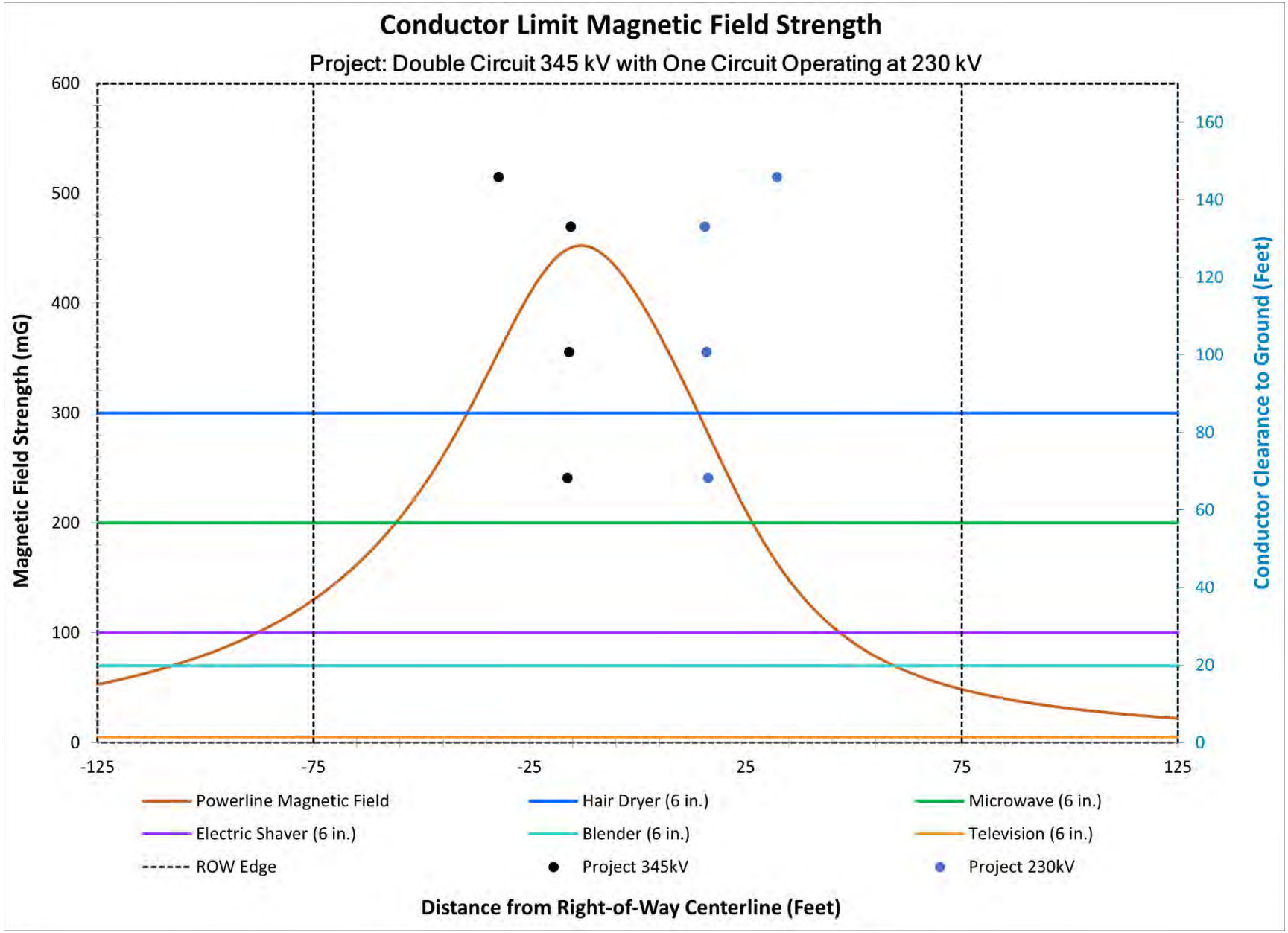


Project: Single-Circuit 345 kV on Double-Circuit Capable
Existing: 230 kV H-frame

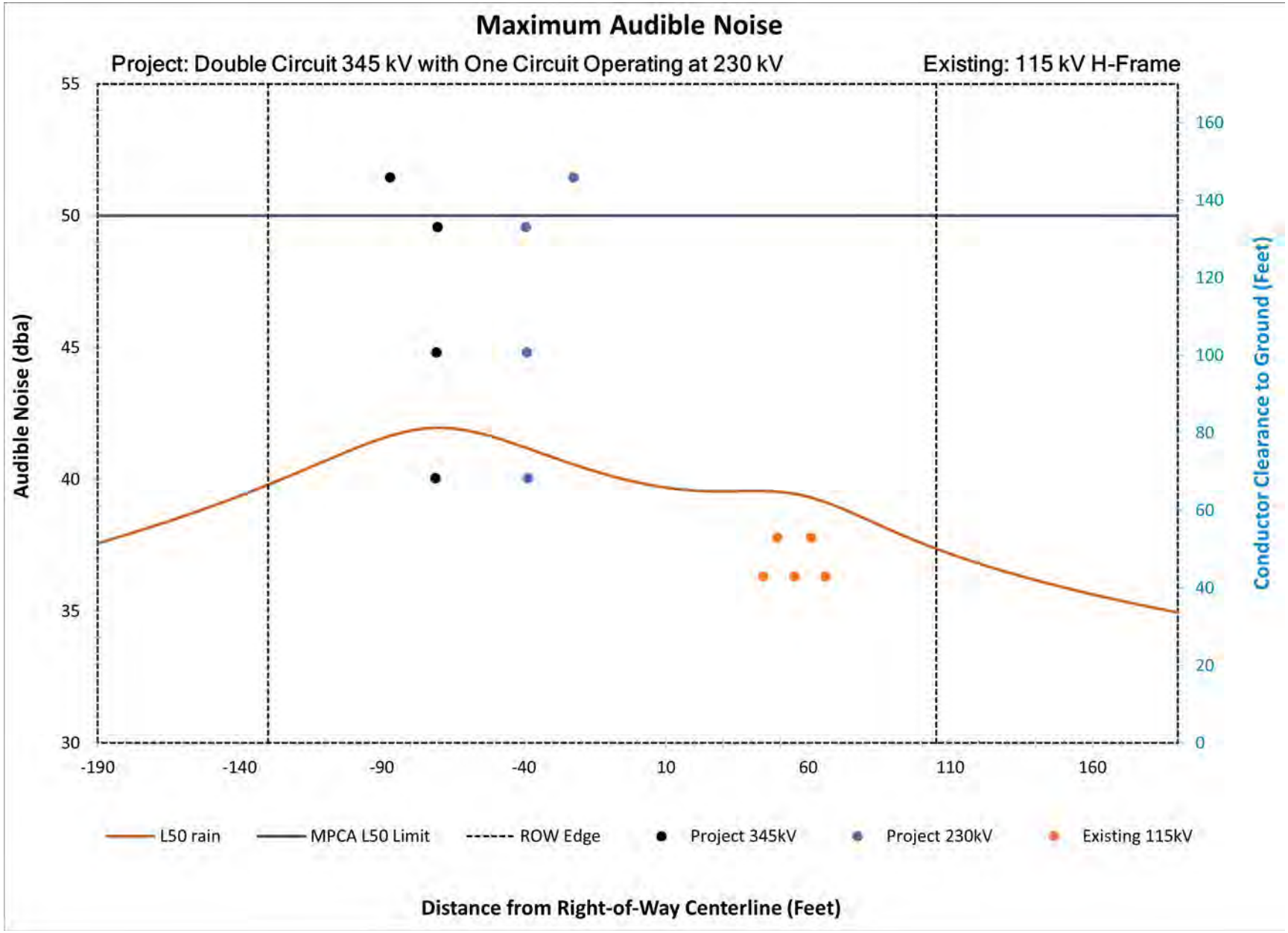



Maximum Audible Noise
Project: Double Circuit 345 kV with One Circuit Operating at 230 kV
Audible Noise (dba)
55
50
45
40
35
30
Conductor Clearance to Ground (Feet)
160
140
120
100
80
60
40
20
0
-125
-75
-25
25
75
125
L50 rain
MPCA L50 Limit
ROW Edge
Project 345kV
Project 230kV
Distance from Right-of-Way Centerline (Feet)

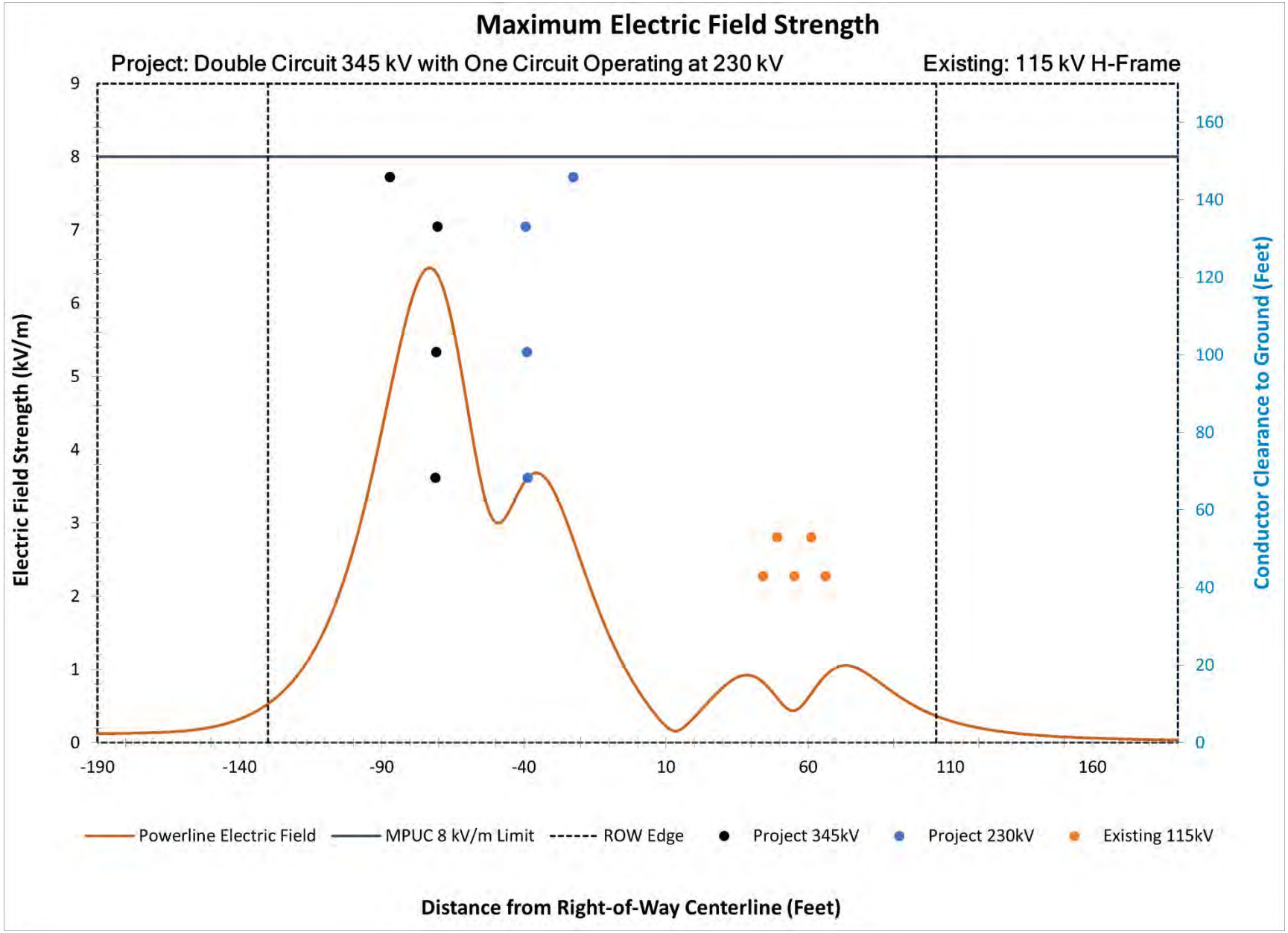

Maximum Electric Field Strength
Project: Double Circuit 345 kV with One Circuit Operating at 230 kV
Electric Field Strength (kV/m)
Conductor Clearance to Ground (Feet)
0
1
2
3
4
5
6
7
8
9
0
20
40
60
80
100
120
140
160
-125
-75
-25
25
75
125
Powerline Electric Field
MPUC 8 kV/m Limit
ROW Edge
Project 345kV
Project 230kV
Distance from Right-of-Way Centerline (Feet)


Conductor Limit Magnetic Field Strength
Project: Double Circuit 345 kV with One Circuit Operating at 230 kV
Magnetic Field Strength (mG)
Conductor Clearance to Ground (Feet)
600
500
400
300
200
100
0
160
140
120
100
80
60
40
20
0
-125
-75
-25
25
75
125
Powerline Magnetic Field
Hair Dryer (6 in.)
Microwave (6 in.)
Electric Shaver (6 in.)
Blender (6 in.)
Television (6 in.)
ROW Edge
Project 345kV
Project 230kV
Distance from Right-of-Way Centerline (Feet)

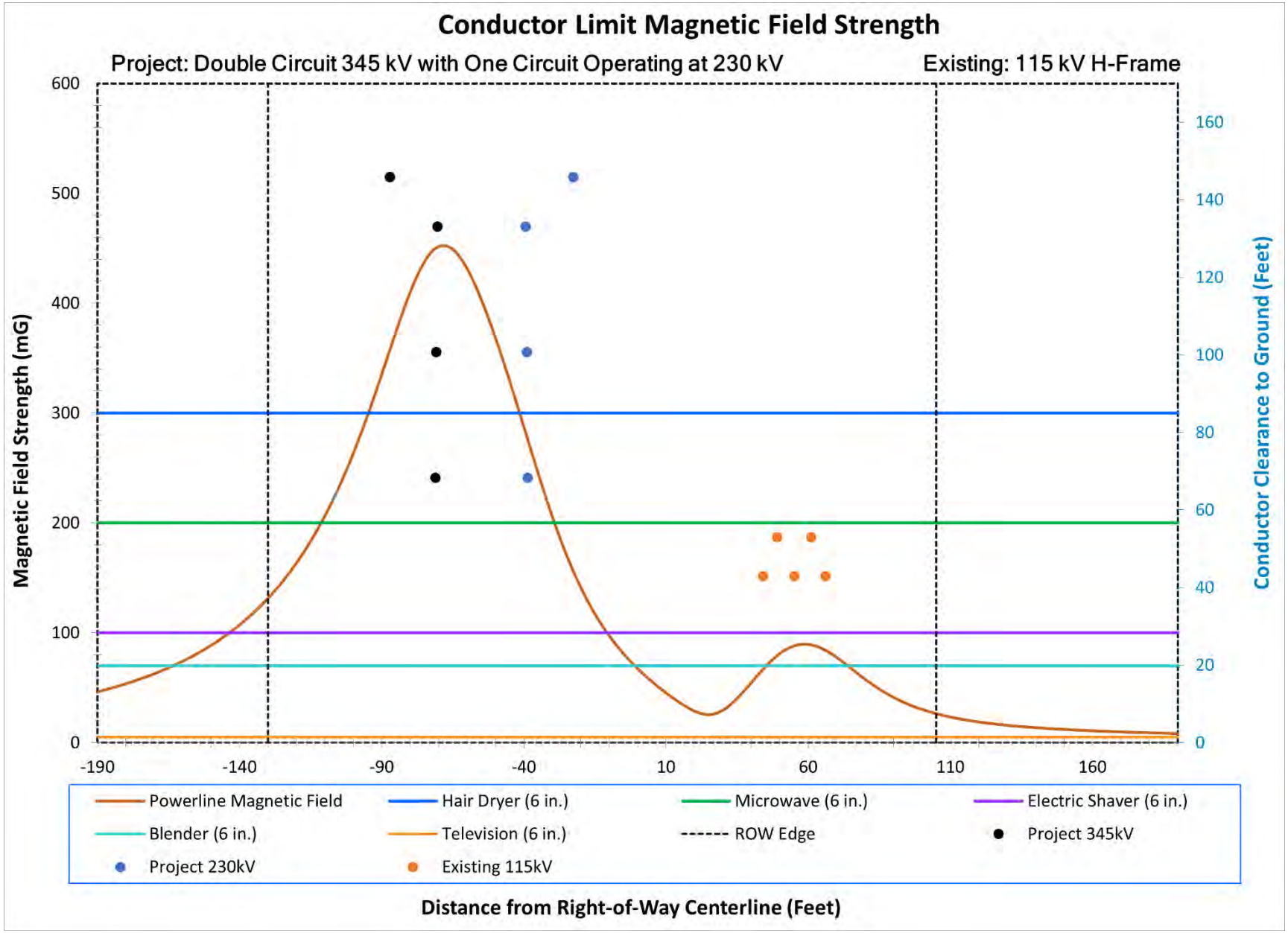
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 115 kV H-Frame



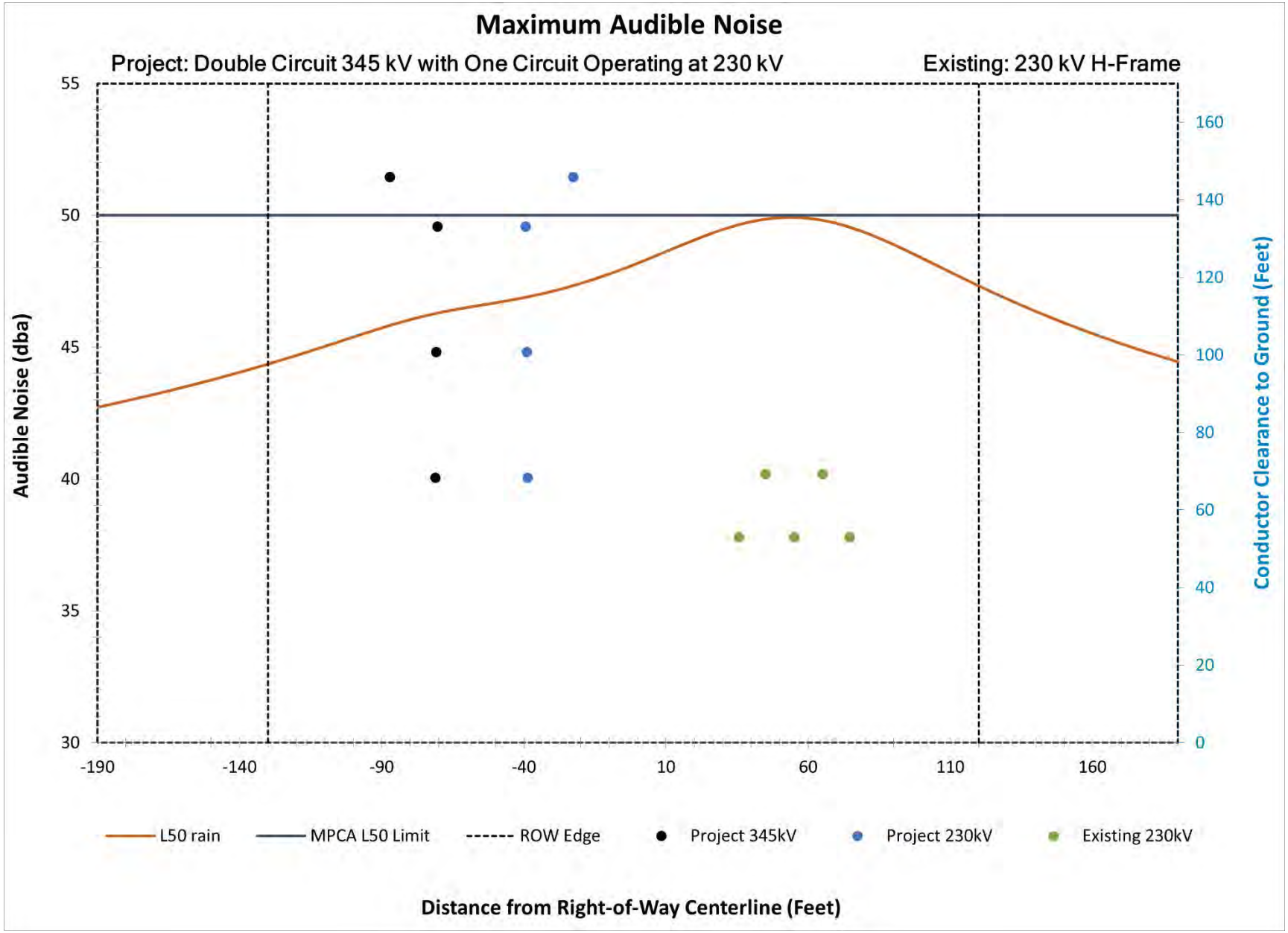
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 115 kV H-Frame



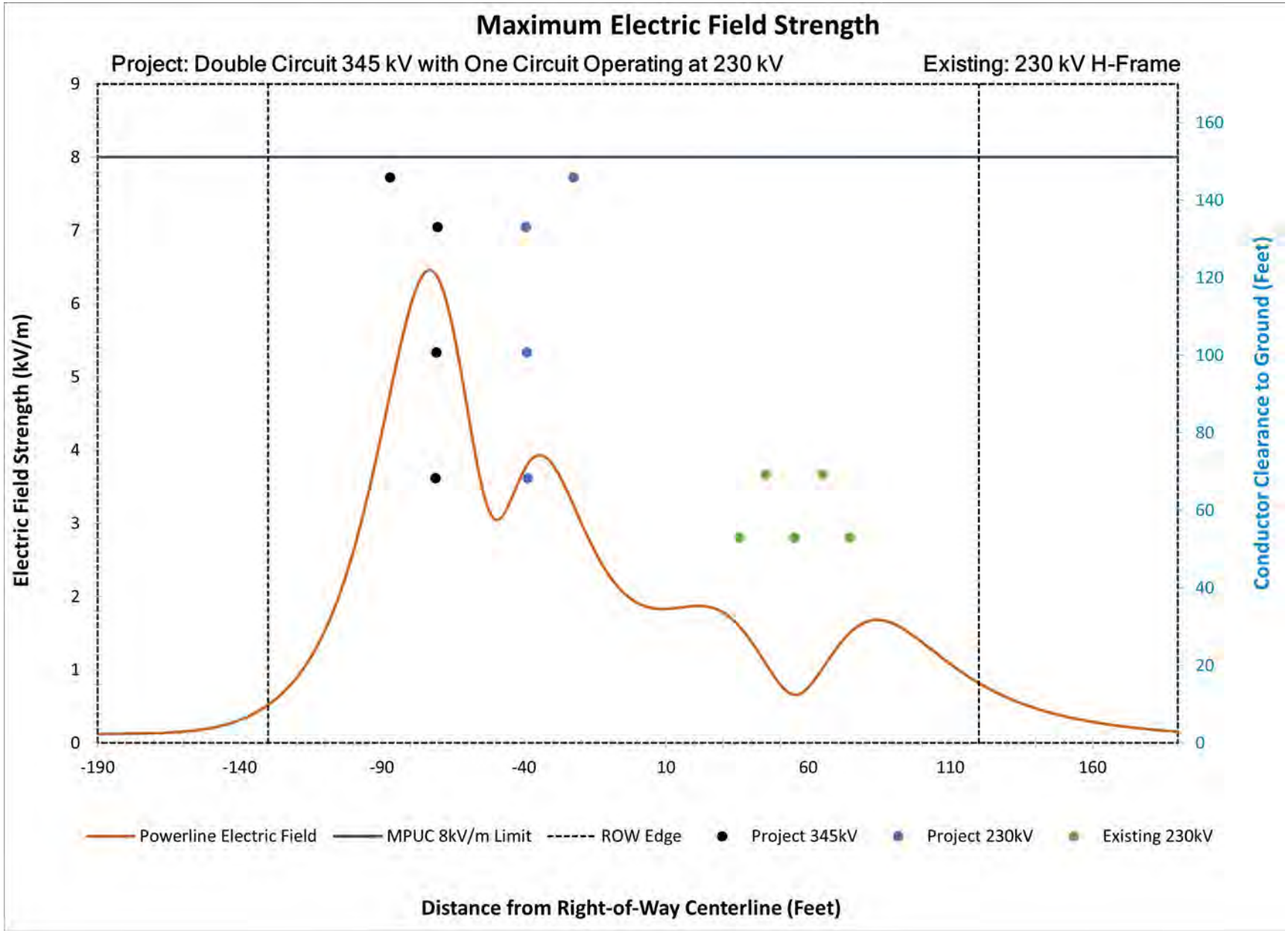
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 115 kV H-Frame



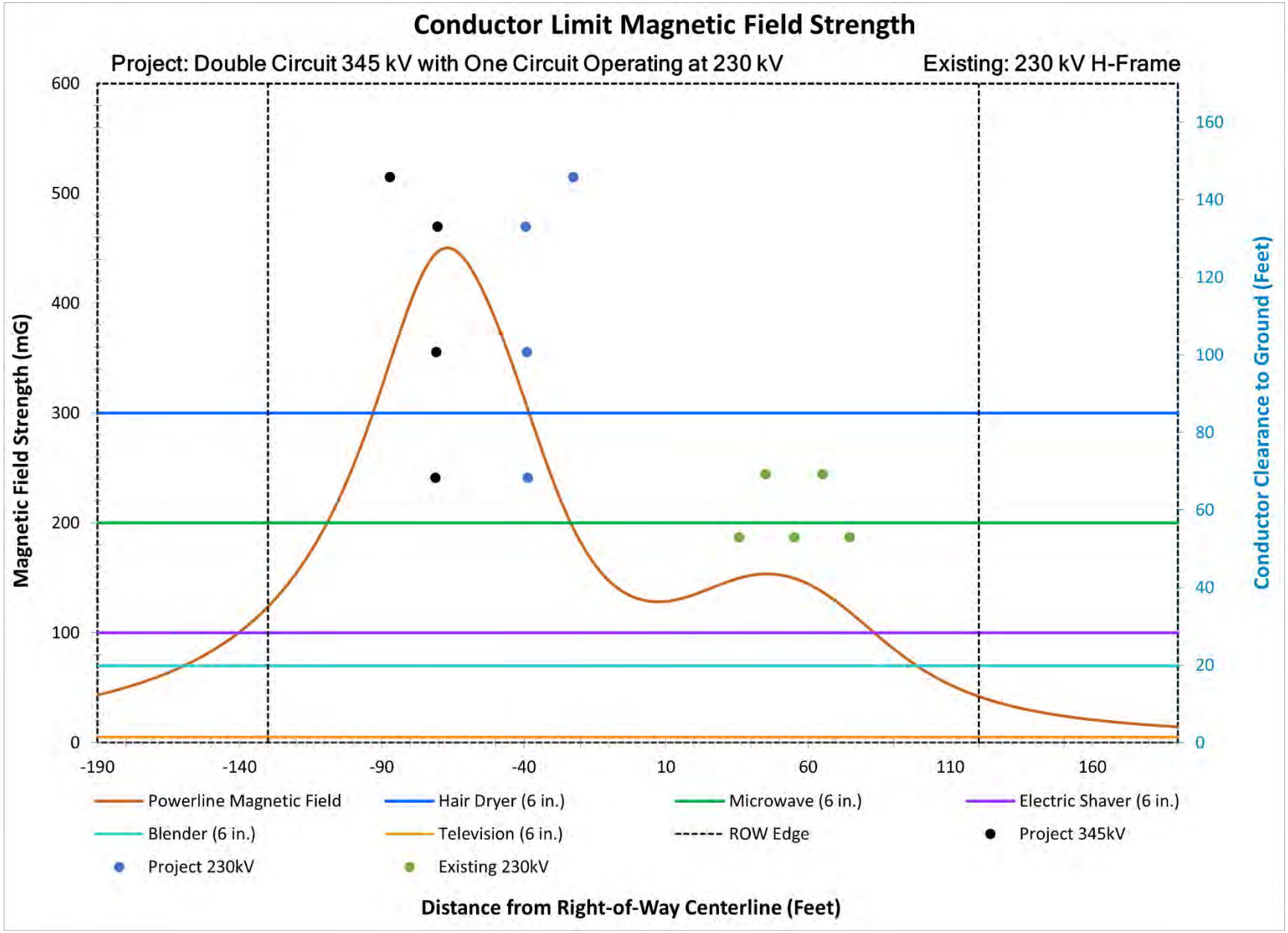
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 230 kV H-Frame



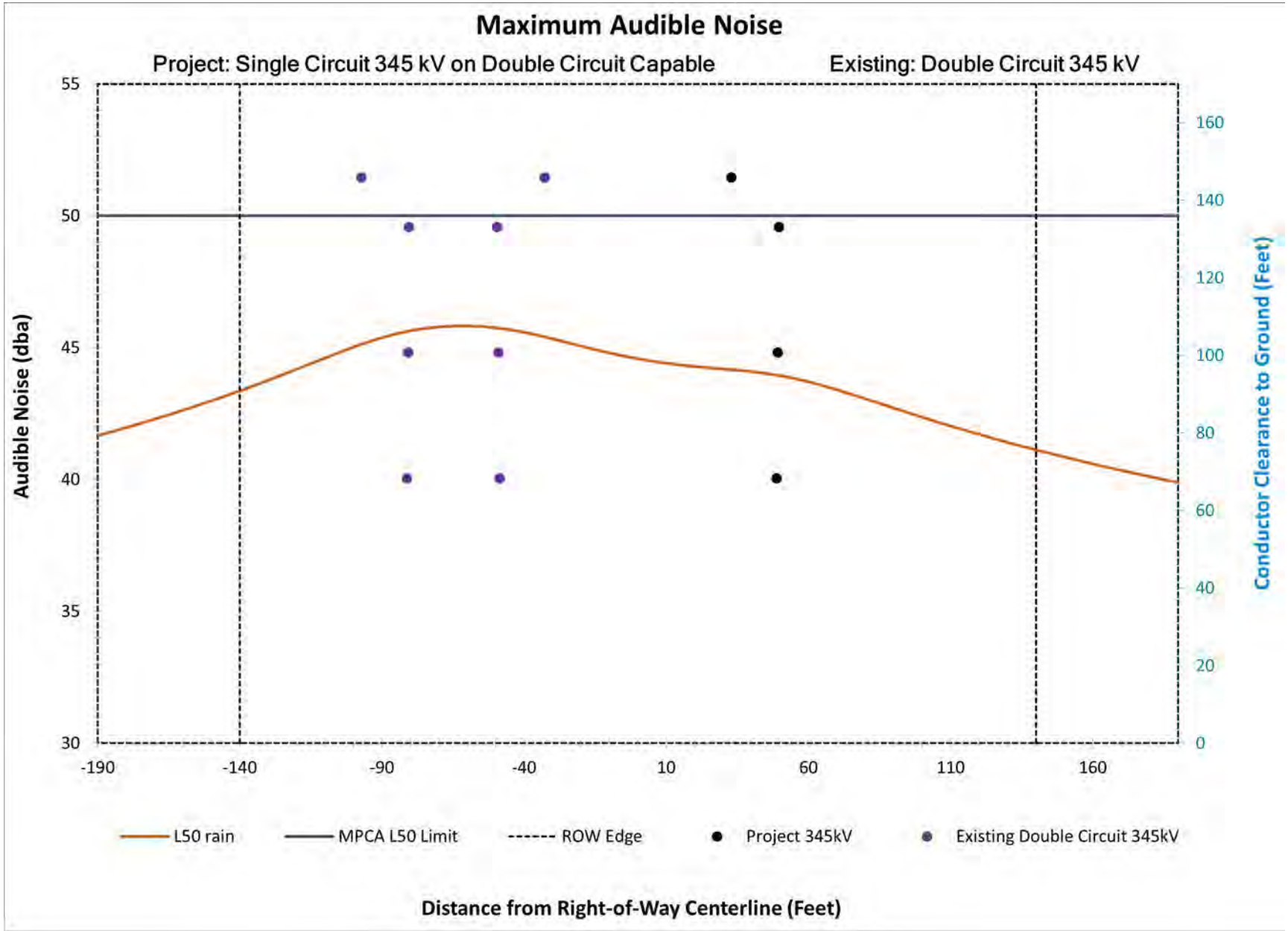
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 230 kV H-Frame



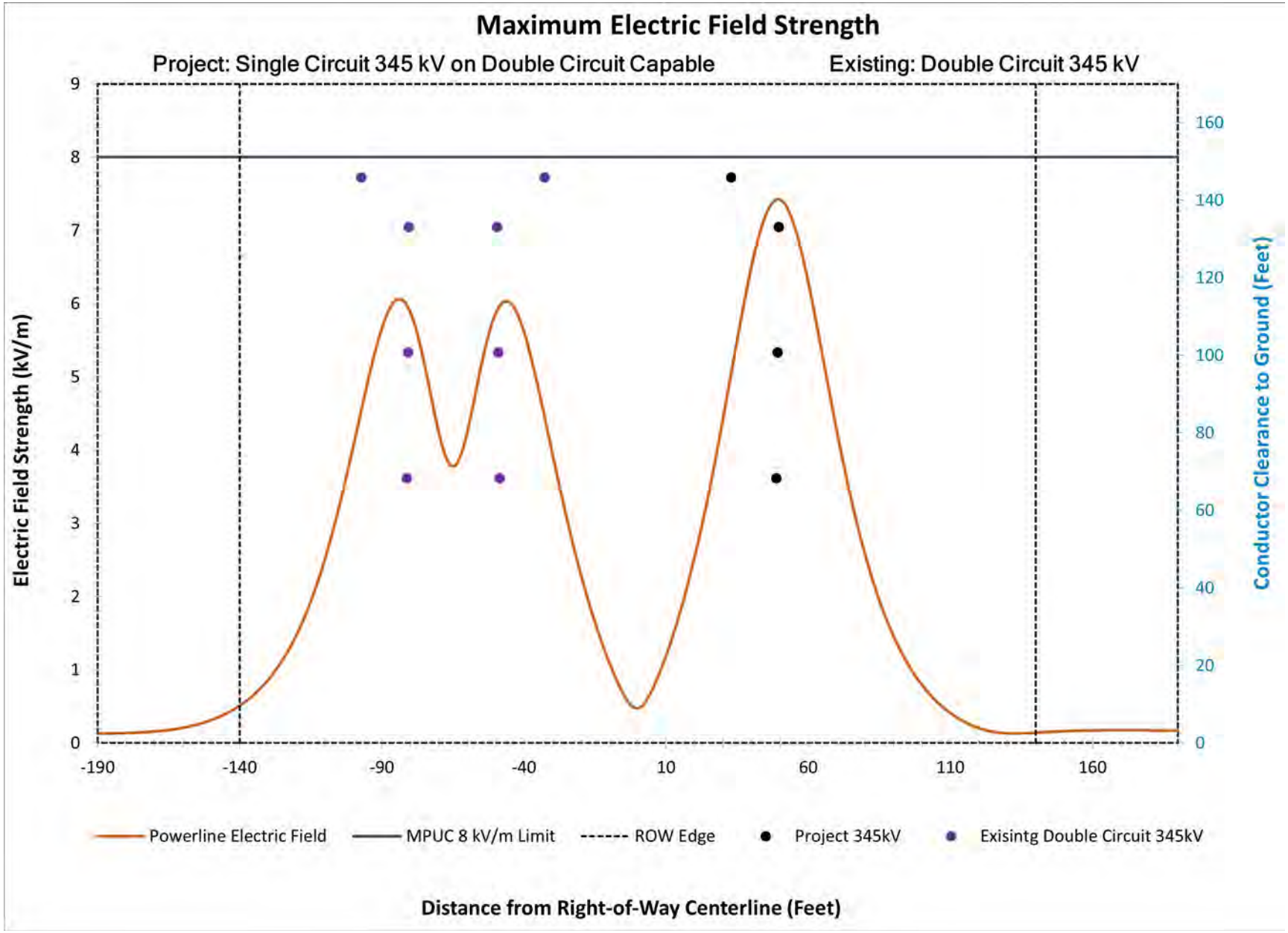
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 230 kV H-Frame



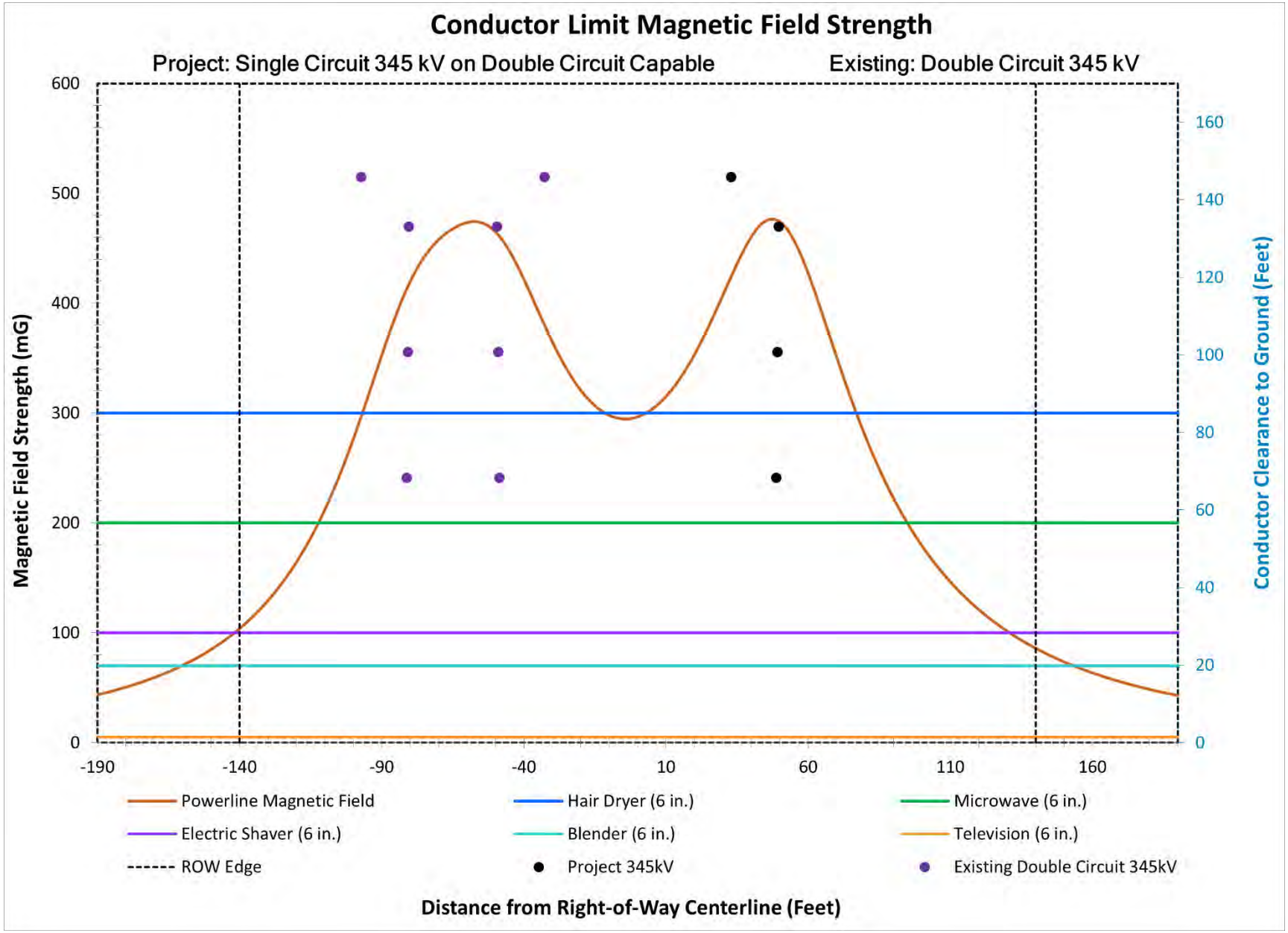
Project: Single-Circuit 345 kV on Double-Circuit Capable
Existing: Double-Circuit 345 kV



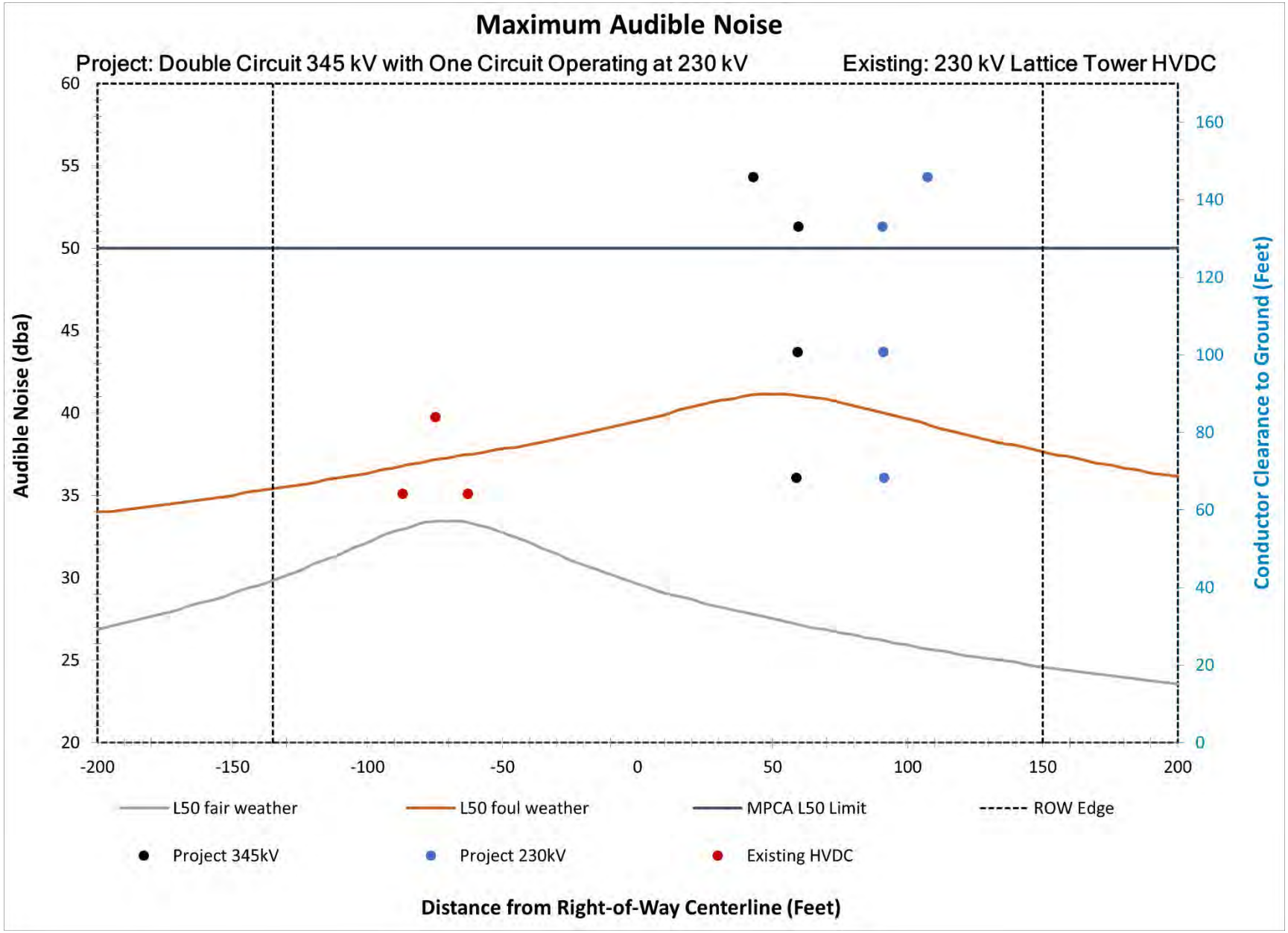
Project: Single-Circuit 345 kV on Double-Circuit Capable
Existing: Double-Circuit 345 kV



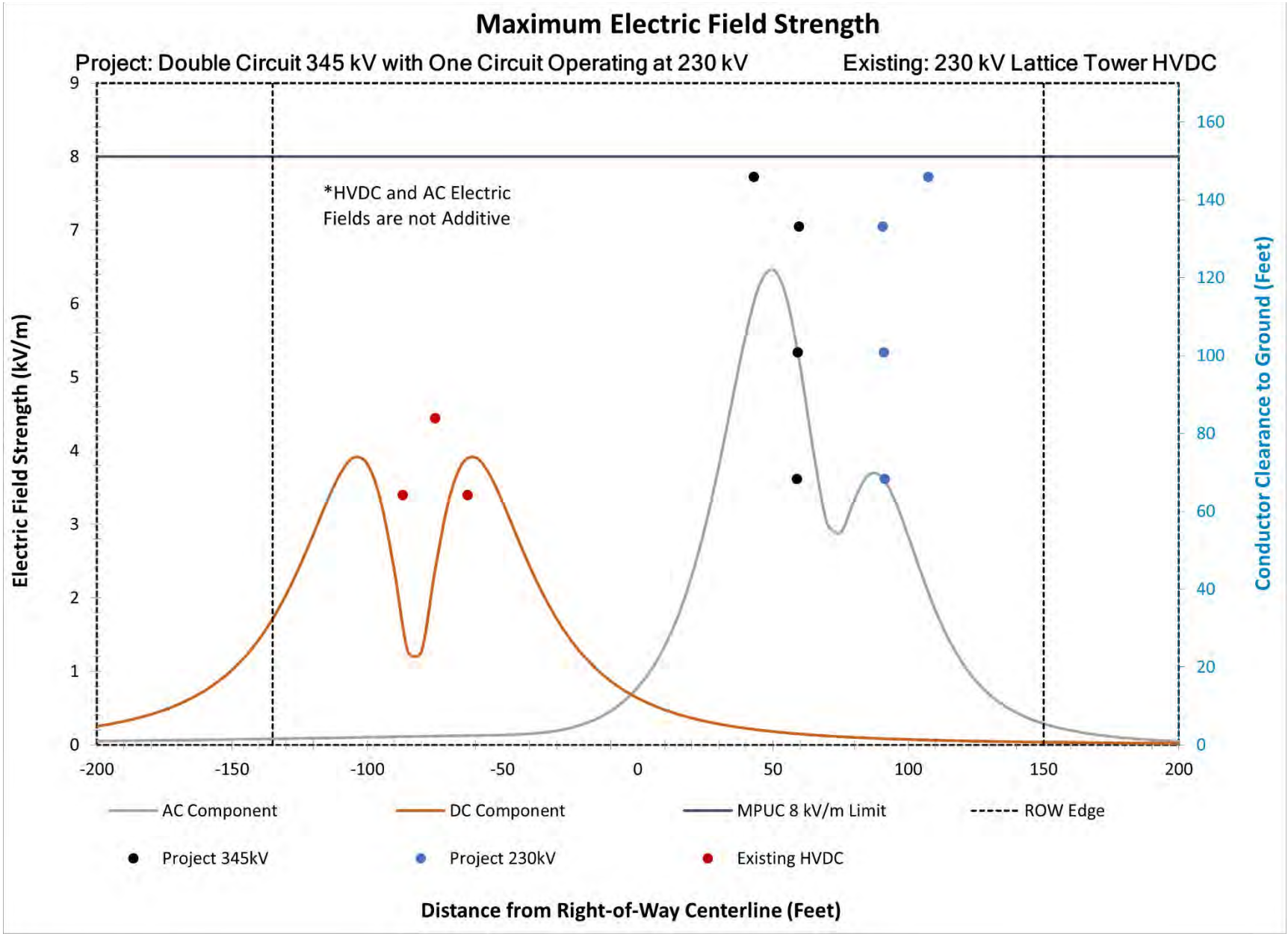
Project: Single-Circuit 345 kV on Double-Circuit Capable
Existing: Double-Circuit 345 kV



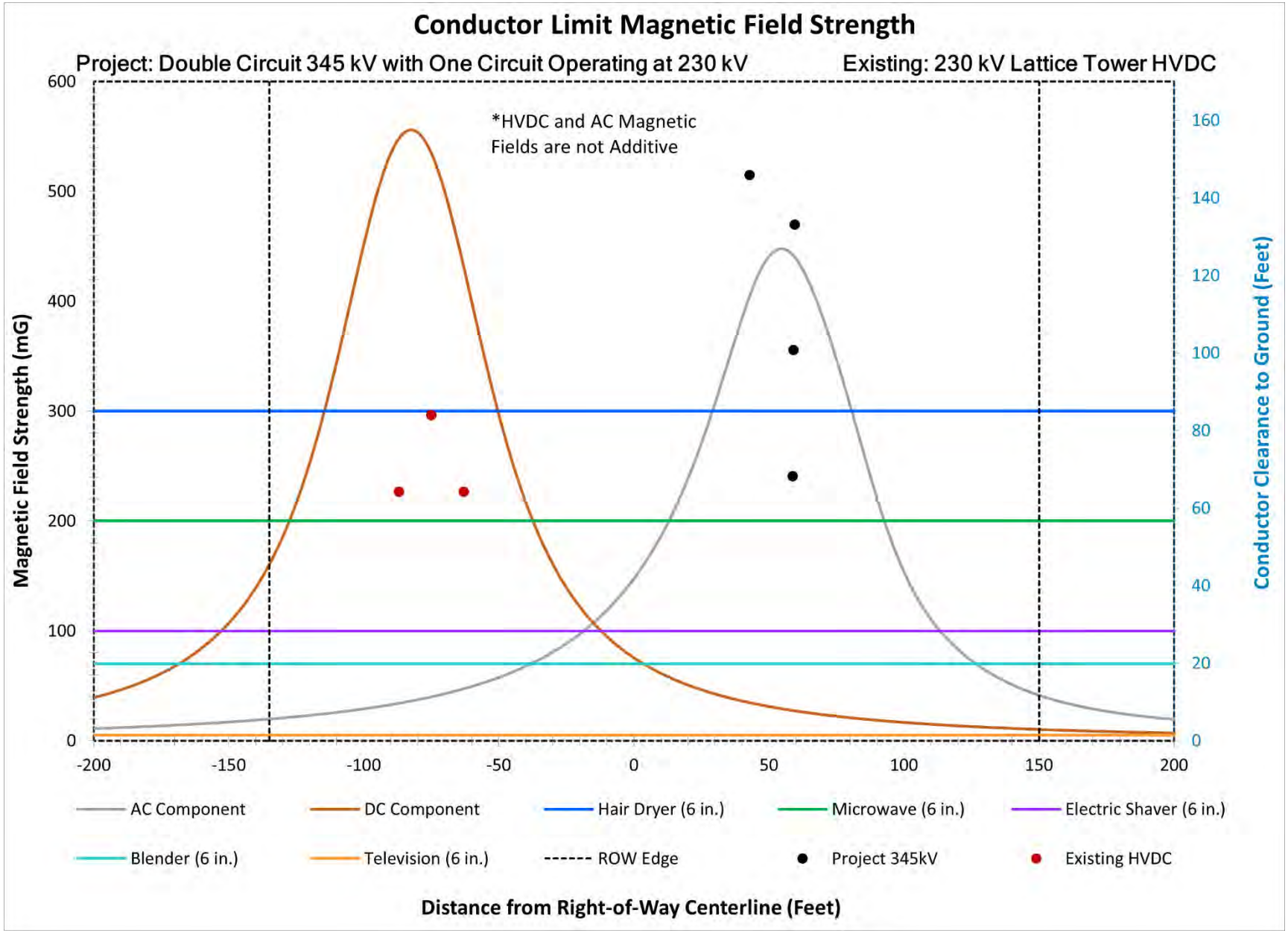
Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 250 kV HVDC



Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 250 kV HVDC



Project: Double-Circuit 345 kV with One Circuit Operating at 230 kV
Existing: 250 kV HVDC



Minnesota Power and American Transmission Company, LLC
Iron Range - St. Louis County - Arrowhead 345 kV Transmission Line Project
Construction Noise Calculations

Backhoe

	Noise Source and Other Conditions/Factors associated with Acoustical Analysis								
	Distance from Equipment (ft)	50	100	200	400	800	1600	3200	6400
	Sound Level Attributable to Backhoe (dBA)	80	74	68	62	56	50	44	38

Crane

	Noise Source and Other Conditions/Factors associated with Acoustical Analysis								
	Distance from Equipment (ft)	50	100	200	400	800	1600	3200	6400
	Sound Level Attributable to Crane (dBA)	80	74	68	62	56	50	44	38

Truck

	Noise Source and Other Conditions/Factors associated with Acoustical Analysis								
	Distance from Equipment (ft)	50	100	200	400	800	1600	3200	6400
	Sound Level Attributable to Truck (dBA)	88	82	76	70	64	58	52	46
	Sound Level Attributable to Two Trucks (dBA)	91	85	79	73	67	61	55	49