IDP Piece	Title	Non-Public Designation
Appendix G	Distributed Intelligence Certification Request	Appendix G contains information Xcel Energy maintains as trade Secret information pursuant to Minn. Stat. § 13.37, subd. 1(b). In particular the Appendix contains confidential information subject to third-party confidentiality agreements. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.
Attachment D	Distribution Risk Scoring Methodology	Attachment D Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. Part III is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material: **1. Nature of the Material:** Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data **2. Authors:** Electric Systems Performance and the Risk Analytics Department **3. Importance:** Key values to determine the potential reliability of certain projects **4. Date the Information was Prepared:** October 29, 2021
Attachment E	Risk Scored Project Details	Attachment E contains two shaded and marked columns that contain (1) forecasted peak demand and (2) peak capacity by feeder and/or substation that Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).
Workpapers	Workpapers - Executable CBA Models - Distributed Intelligence	The Distributed Intelligence CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use. Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material: **1. Nature of the Material**: The Cost Benefit Analysis Model developed by the Company. **2. Authors**: Risk Analytics **3. Importance**: The Company work product is proprietary to the Company. **4. Date the Information was Prepared**: The CBA Model was created in the third quarter of 2021.
Workpapers	Workpapers - Executable CBA Model - Resilient Minneapolis Project	The Resilient Minneapolis Project CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use. Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material: **1. Nature of the Material**: The Cost Benefit Analysis Model developed by the Company. **2. Authors**: Risk Analytics **3. Importance**: The Company work product is proprietary to the Company. **4. Date the Information was Prepared**: The CBA Model was created in the third quarter of 2021.

Statute	Requirement	Location
Minn. Stat. § 216B.2425, subd. 2(e).	In addition to providing the information required under this subdivision, a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.	Appendix B1: Grid Modernization Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request
Minn. Stat. § 216B.2425, subd. 3.	Subd. 3.Commission approval. By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. The commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is: (1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers; (2) needed, applying the criteria in section 216B.243, subdivision 3; and (3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.	Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request

Order Point	MPUC IDP Requirement (8/7/18 Order in Docket No. E002/M-17-775 & E002/M-17-776)	Location
11	Xcel may file a Grid Modernization Report and certification request on November 1, 2018 in combination with an Integrated Distribution Plan in Docket No. E-002/CI-18-251. The filing should include for any certification request(s) at a minimum: (1) details on why the project is necessary for grid modernization; (2) how it is in the public interest; (3) how it is consistent with the Commission's Guiding Principles for Grid Modernization (Docket 15-556); (4) the intended objectives for the project; (5) a description of the available alternatives to meet the intended objectives; (6) a cost benefit analysis of the project; (7) and potential interrelation with other initiatives, projects, and Xcel's long-term grid modernization plans.	Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request, Workpapers (CBAs)

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
	Planning Objectives	The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to: •Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies; •Enable greater customer engagement, empowerment, and options for energy services; •Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and, •Ensure optimized utilization of electricity grid assets and resources to minimize total system costs. •Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
		Commission review of ~~annual~~ distribution system plans is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments. *(Note: Modified to remove "annual" in 11/2/2020 Order in Docket No. E002/M-19-666.)*	N/A
		For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement: 1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive; 2. How the information could be obtained, at what estimated cost, and timeframe; 3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives; 4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.	N/A
1	Distribution System Plan Process	Filing Date: Require Xcel to file annually with the Commission beginning on November 1, 2018 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (E002/M-17-776).	Superseded by Order Point 2. in Docket No. E002/M-19-666
2	Stakeholder Meetings	Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	Appendix I: Stakeholder Engagement Workshop 9/17/21

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	Appendix A1: System Planning
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	Appendix A4: Distribution System Statistics
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	Appendix A4: Distribution System Statistics
3.A.4	Baseline Distribution System and Financial Data System Data	Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available	Appendix A4: Distribution System Statistics
3.A.5	Baseline Distribution System and Financial Data System Data	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans	Appendix A1: System Planning
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DER is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018).	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	Appendix A4: Distribution System Statistics
3.A.9	Baseline Distribution System and Financial Data System Data	For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system	Appendix A4: Distribution System Statistics
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	Appendix A4: Distribution System Statistics
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	Appendix A4: Distribution System Statistics
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	Appendix A4: Distribution System Statistics
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	Appendix A4: Distribution System Statistics
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	Appendix A4: Distribution System Statistics

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.15	Baseline Distribution System and Financial Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public electric vehicle charging stations	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.25	Baseline Distribution System and Financial Data System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.26	Baseline Distribution System and Financial Data Financial Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other The Company may provide in the IDP any 2018 or earlier data in the following rate case categories: a. Asset Health b. New Business c. Capacity d. Fleet, Tools, and Equipment e. Grid Modernization For each category, provide a description of what items and investments are included.	Appendix D: Distribution Financial Framework and Information

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.27	Baseline Distribution System and Financial Data Financial Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.A.28	Baseline Distribution System and Financial Data Financial Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	Appendix D: Distribution Financial Framework and Information
3.A.29	Baseline Distribution System and Financial Data Financial Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	Appendix D: Distribution Financial Framework and Information Attachment H: Capital Project List by IDP Category Attachment I: Capital Profile Trend Attachment J: O&M Profile Trend
3.A.30	Baseline Distribution System and Financial Data Financial Data	Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	Appendix A1: System Planning
3.A.31	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers “high” DER penetration.	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547 Appendix E2: Distributed Energy Forecast Methodology and Forecasts

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources4, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.5 (Footnote: Forthcoming Order, E999/CI-16-521, MN DIP 3.2 Initial Review)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.	Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	Appendix E2: Distributed Energy Forecast Methodology and Forecasts
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	*Merged into 3.D.2 per July 16, 2019 Order in Docket No. E002/CI-18-251.*	N/A
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above).	Appendix A1: System Planning, Appendix C: Grid Modernization Action Plans, Attachment F:Planning Area Load Growth Assumptions, Attachment H: Capital Project List by IDP Category
		Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	See 3.2.D Subparts below.

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.D.2 (i)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Overview of investment plan: scope, timing, and cost recovery mechanism	Appendix C: Grid Modernization Action Plans
3.D.2 (ii)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise. (Footnote: https://gridarchitecture.pnnl.gov/)	Appendix B1: Grid Modernization
3.D.2 (iii)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request
3.D.2 (iv)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	System interoperability and communications strategy	Appendix B1: Grid Modernization
3.D.2 (v)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
3.D.2 (vi)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Appendix B2: Customer Strategy & Roadmap
3.D.2 (vii)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer anticipated benefit and cost	Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request, Workpapers (CBAs)
3.D.2 (viii)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Appendix B3: Operational and Planning Data Management, Data Security, and Data Access Plans and Policies
3.D.2 (ix)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Plans to manage rate or bill impacts, if any	Appendix C: Grid Modernization Action Plans, Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request
3.D.2 (x)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Appendix C: Grid Modernization Action Plans, Attachment G: Distribution Function NPV

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.D.2 (xi)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	For each grid mod project in its 5-year action plan, Xcel should provide a cost-benefit analysis <u>based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.</u> *(Note: Underlined portion added per 7/16/19 Order in Docket No. E002/CI-18-251).*	Appendix G: Distributed Intelligence Certification Request, Appendix H: Resilient Minneapolis Project Certification Request, Workpapers (CBAs)
3.D.2 (xii)	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Status of any existing pilots or potential for new opportunities for grid mod pilots.	Appendix B4: Existing and Potential New Grid Modernization Pilots
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	Appendix C: Grid Modernization Action Plans
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	Appendix F: Non-Wires Alternatives Analysis, Attachment L: Non-Wires Alternatives Analysis
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide information on the following: •Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) •A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) •Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed •A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	Appendix F: Non-Wires Alternatives Analysis, Attachment L: Non-Wires Alternatives Analysis

Order Pt.	MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)	Location
3	IDP Requirement 3.D.2 shall be amended as follows: For each grid modernization project in its 5-year Action Plan, require Xcel to provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quanitfiable benefits. Xcel shall provide all information used to support its analysis.	See 8/30/18 E002/CI-18-251 Requirement 3.D.2 (xi)
4	IDP Requirement 3.D.2 shall be amended to merge Requirement 3.D.1 into 3.D.2 as follows: Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER fugtures analysis, hosting capacity analysis, and non-wire alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel shall include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum: [As stated in the Aug 30, 2018 IDP filing requirements at 6].	See 8/30/18 E002/CI-18-251 Requirement 3.D.2
5	Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including: A. An analysis of how the information presented in the IDP related to each Planning Objective, B. The location in the IDP, C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
6	Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	No longer relevant - see Company's October 30, 2020 filing in Docket No. E002/M-19-666 at Page 6.
7	Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.	Appendix A1: System Planning
8	Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	No longer relevant - provided in Docket No. E002/M-19-666.
9	Xcel shall provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology, in future IDPs.	Appendix F: Non-Wires Alternatives Analysis, Attachment L: Non-Wires Alternatives Analysis
10	Xcel shall provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.	Attachment D: Distribution Risk Scoring Methodology, Attachment E: Risk Score Project Details
11	Xcel shall file any long-range distribution studies it had conducted in the time since the last IDP.	N/A for 2020 Appendix A1: System Planning

Order Pt.	MPUC IDP Requirement (7/23/20 Order in Docket No. E002/M-19-666)	Location
2	Xcel must file Integrated Distribution Plans biennially going forward. The Company's next IDP must be filed no later than November 1, 2021.	November 1, 2021 Filing
3	Xcel must continue to file an annual update of baseline financial data and non-wires alternatives analysis.	October 30, 2020 Filing
4	In the DER Scenario Analysis of future IDPs, Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.	Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547
5	Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA.	Appendix I: Stakeholder Engagement Workshop 9/17/21
6	Xcel must engage stakeholders in further advancing the Company's NWA Analysis, including, but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.	Appendix I: Stakeholder Engagement Workshop 9/17/21
9	The Commission requests that the Department file a report by November 1, 2020, including recommendations on specific metrics, detailed methods for evaluating performance, and consumer protections or other conditions, including cost caps, that should be applied to the certified projects. The report should be informed by a stakeholder process and will be made part of the record for any future cost recovery proceedings. **Xcel must participate in the stakeholder process, which must be open to all interested parties, and fully cooperate with the Department.**	Confirmed - Xcel Energy participated in all workshops for Docket No. E002/DI-20-627 (10/23/2020; 11/20/2020)
12	Xcel must produce a draft rate design "roadmap" with input from stakeholders and file it with the Commission by October 1, 2020. The Commission delegates authority to the Executive Secretary to set schedules and gather information on, or refer to the appropriate docket(s), the following: a. A summary of the Company's current advanced rate designs and demand management programs, advanced rate designs in development, and relevant industry best practices. b. A timeline for proposing advanced rates and/or demand management programs for all customer classes. c. A discussion on what should be discussed in petitions for rate design changes, including: i. Whether program design strategies will be needed to support low income customer participation in these offerings, ii. Application to distributed energy resources and beneficial electrification, iii. Implementation plans, including education and outreach to customers, and iv. Evaluation plans.	Filed 10/1/2020 in Docket No. E002/M-19-666

Order Pt.	MPUC IDP Requirement (7/23/20 Order in Docket No. E002/M-19-666)	Location
13	60 days prior to a petition to seek rider recovery for AGIS costs, Xcel Energy shall file preferred procedural paths forward with one option being a contested case. The Commission will make a procedural and scoping decision prior to the consideration of a rider recovery determination. The Executive Secretary is authorized to establish a comment and reply schedule prior to the procedural and scoping hearing.	Filed 8/28/2020 in Docket No. E002/M-19-666

Order Pt.	MPUC IDP Requirement (11/2/20 Order in Docket No. E002/M-19-666)	Location
4	Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association's IDP filing requirements in the second paragraph under Planning Objectives are corrected as shown: Commission review of ~~annual~~ distribution system plans are is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.	See 8/30/18 E002/CI-18-251 Planning Objectives.

Correlation of IDP Content to Commission's IDP Planning Objectives

The Commission's July 16, 2019 Order in Docket E002/CI-18-251 requires the Company to discuss in future filings how the IDP meets the Commission's Planning Objectives, including:

A. An analysis of how the information presented in the IDP related to each Planning Objective,
B. The location in the IDP,
C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and
D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.

The Commission's August 30, 2018 Order in Docket E002/CI-18-251 provided the Commission's Planning Objectives. Specifically, it noted that Xcel Energy's distribution system planning is to be guided by the following principles and planning objectives:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies;
- Ensure optimized use of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value

We have followed the format the Department used in their February 22, 2019 Comments in Docket E002/CI-18-251(as well as our 2019 IDP filing in Docket No. E002/M-19-666) in complying with the Commission's requirement.

A. Planning Objective #1

As noted above, the first planning objective of the IDP is designed to maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies. We provide a high-level analysis of the location of these topics in the IDP in Table 1 below.

Table 1: Location of Topics of the First Planning Objective in the IDP

Topic	IDP Location
Safety	Integrated Distribution Plan Appendix A1 – System Planning Appendix A2 – Asset Health and Reliability Mgmt Appendix A3 – Distribution Operations Appendix B2 – Customer Strategy and Roadmap Appendix B3 – Customer and Operational Data Mgmt Appendix D – Distribution Financial Information Appendix E1 – System Interconnection Appendix E2 – DER Methodology and Forecasts Appendix G – DI Certification Appendix H – RMP Certification
Security	Integrated Distribution Plan Appendix A1 – System Planning Appendix B1 – Grid Modernization Appendix B3 – Customer and Operational Data Mgmt Appendix C – Action Plans Appendix D – Distribution Financial Information Appendix E1 – System Interconnection Appendix G – DI Certification Appendix H – RMP Certification
Reliability	Integrated Distribution Plan Appendix A1 – System Planning Appendix A2 – Asset Health and Reliability Mgmt Appendix A3 – Distribution Operations Appendix A4 – Distribution System Stats Appendix B1 – Grid Modernization Appendix B2 – Customer Strategy and Roadmap Appendix B3 – Customer and Operational Data Mgmt Appendix C – Action Plans Appendix D – Distribution Financial FramInformation Appendix E1 – System Interconnection Appendix E2 – DER Methodology and Forecasts Appendix F – Non-Wires Alternatives Analysis Appendix G – DI Certification Appendix H – RMP Certification Appendix I – Stakeholder Outreach
Resilience	Integrated Distribution Plan Appendix A2 – Asset Health and Reliability Mgmt Appendix A3 – Distribution Operations Appendix B1 – Grid Modernization Appendix G – DI Certification Appendix H – RMP Certification

Table 1: Location of Topics of the First Planning Objective in the IDP (*Cont'd*)

Fair and Reasonable Costs	Integrated Distribution Plan Appendix A1 – System Planning Appendix A2 – Asset Health and Reliability Mgmt Appendix A3 – Distribution Operations Appendix B1 – Grid Modernization Appendix C – Action Plans Appendix D – Distribution Financial Information Appendix E1 – System Interconnection Appendix F – Non-Wires Alternatives Analysis Appendix G – DI Certification Appendix H – RMP Certification
Consistent with State Energy Policies	Integrated Distribution Plan Appendix A1 – System Planning Appendix B1 – Grid Modernization Appendix C – Action Plans Appendix E2 – DER Methodology and Forecasts Appendix G – DI Certification

As suggested by the table above, the Company addressed each of the topics of the first planning objective in a substantive way.

B. Planning Objective #2

The second planning objective of the IDP is to enable greater customer engagement, empowerment, and options for energy services.

Our IDP Report has a robust discussion with regard to these three topics. First, the main body of the IDP provides an overview of the customer-oriented outcomes expected from deploying advanced grid infrastructure and advanced technologies. We state:

> *In combination with our distribution strategy, we have developed a customer strategy that aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect….*
>
> *….In addition to providing our customers with direct benefits and insights into their energy usage, our planned grid modernization investments will combine to provide the Company with greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.*

There are also related discussions in Appendix B1 (Grid Modernization) and Appendix B2 (Customer Strategy and Roadmap) when discussing our plans for Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), and Advanced Distribution Management System (ADMS), each of which are technological innovations that are geared toward fulfilling the second planning objective.

Additionally, one of the projects proposed for certification is geared toward customer engagement. Appendix G discusses our Distributed Intelligence (DI) investment, saying:

> *The DI capabilities of the new meters will enable the Company to provide customers with more detailed information regarding their energy usage, which will empower them to make decisions for financial and/or environmental reasons.*

Our other proposed project for certification, the Resilient Minneapolis Project (RMP) discussed in Appendix H also has a focus on empowerment and community resiliency.

The IDP also provides extensive discussions Appendix E2 (Distributed Energy Resources), Appendix E1 (Hosting Capacity and System Interconnection), and Appendix B4 (Grid Modernization Pilots) which all also support the Commission's second planning objective to enable greater customer engagement, empowerment, and options for energy services.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the second planning objective. However, this does represent that we provided extensive information and discussion of items related to the second planning objective.

Planning Objective #3

The third planning objective of the IDP is designed to move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Much of the information and discussion provided in the IDP related to the second planning objective are also applicable to the third planning objective. Our description of our AGIS initiative, of which AMI, FAN, FLISR, and ADMS were discussed, provides information and discussion relevant to the third planning objective. These are discussed throughout the filing but particularly in Appendix B1 (Grid

Modernization), Appendix B2 (the Customer Strategy and Roadmap) and Appendix E1 (System Interconnection and Hosting Capacity).

Additionally, the advanced planning tool, LoadSEER, discussed throughout the document but particularly in Appendix B1 (Grid Modernization), also relates to the third planning objective.

Finally, Appendix B4 (Existing and Potential New Grid Modernization Pilots) also relates to the third planning objective. Specifically, we provide information on our TOU Rate Pilot, electric vehicle (EV) programs, a residential battery demand response pilot, and two potential new time of use rate structure pilots for general service customers. Each of these pilots supports the third planning objective as they provide potential new platforms for new products, new services, and opportunities for adoption of new distributed technologies.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the third planning objective. However, this does represent that we provided extensive information and discussion of items related to the third planning objective.

C. Planning Objective #4

The fourth planning objective of the IDP is designed to ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In the IDP, we discuss our efforts toward integrating Distribution, Transmission, and Resource Planning in Appendix A1 (System Planning), which entirely supports the fourth planning objective.

In the context of the Company's planning efforts related to distributed energy resources (DER), we also provide Appendix E2 (Distributed Energy Resources).

The investments that we are currently making in asset health and reliability management, discussed in Appendix A2, and grid modernization, such as ADMS, AMI, and FLISR help to lay the foundation for continued resiliency and reliability. Near-term future planned AGIS investments such as AMI further cement it, and will allow us to respond to increased DER penetration. These are discussed throughout the filing but particularly in Appendix B1,Grid Modernization.

Again, we note that this list is not exhaustive of the items discussed in the IDP that relate to the fourth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fourth planning objective.

D. Planning Objective #5

Finally, and as noted above, the fifth planning objective of the IDP is to provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of customer cost and value.

The IDP provides a comprehensive discussion about our short-term and long-term distribution system plans and investments within Appendix A3 (Distribution Operations), Appendix C (Action Plans), and Appendix B1 (Grid Modernization)

In addition, we provide a through description of how we plan the distribution system in Appendix A1 (System Planning) as well as how we develop the budget in Appendix D (Distribution Financial Information).

With regard to the costs and benefits of specific investments, we discuss this throughout the IDP. In particular, we provide Appendix F (Non-Wires Alternatives Analysis), which provides the analyses we performed to evaluate non-traditional distribution system solutions to our traditional distribution solutions. We also provide cost benefit analysis for the projects for which we seek certification in Appendix G (DI) and Appendix H (RMP).

With regard to customer value, in Appendix B1 (Grid Modernization), we discuss the overall customer proposition for AGIS, including drivers of the initiative and expected customer and system benefits. We also provide the impacts to net present value of system cost in Appendix C (Action Plans)

We note that this list is not exhaustive of the items discussed in the IDP that relate to the fifth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fifth planning objective.

E. IDP Filing Requirement Refinements

Finally, with respect to the last discussion point requesting the Company provide suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives, we do not have any refinements at this time. Though we note that, consistent with the Commission's Order in our last IDP (Docket No. E002/M-19-666) and consistent with other Minnesota utilities and the grid modernization statute filing requirements, we continue to believe that a full two years between IDP filings, allows us to make more significant and meaningful progress on the IDP objectives between filings.

I. RISK SCORING METHODOLOGY

As part of our risk analysis and mitigation processes, discussed as part of our annual System Planning process, Xcel Energy personnel enter projects throughout the year in the Risk Register/Workbook. Along with the description of the project, the originator must identify the primary business value driving the investment and may also enter the benefit and any associated service quality metric impacts (i.e., customer minutes out, which impacts System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), etc.). After Distribution Operations and Risk Analytics review the projects to ensure the data is accurate, Business Area Finance sets-up all appropriate accounting structures.

Projects are then run through the risk model for scoring. This process involves a number of steps:

- A project's raw financial benefit is calculated based on a project's gross cash flow (generally, incremental revenue plus realized salvage value less incremental recurring costs, non-recurring costs (e.g., taxes), and capital expenditures) and avoided costs.
- A project's raw reliability benefit is calculated based on overload customer minutes out (considering mega volt-amperes (MVA) beyond threshold, customers per MVA, capacity, demand growth, and annual hours at risk). It is also based on contingency customer minutes out (considering peak load less available relief MVA, customers per MVA, time to restore, peak day hours out, annual hours at risk, and yearly failure rate of equipment at risk), and the number of customer complaints to the public utilities commission.
- The raw reliability benefit is converted into the same metric as the raw financial benefit using a conversion factor (e.g., $1.25/customer minute out) based on an algorithm.
- Jurisdictional factors (including discount rates, income tax rates, property tax rates, inflation rates, historical Commission complaints, historical Quality of Service plan (QSP) SAIDI data, and historical transformer failure data) are then applied to the financial benefit and reliability benefit.
- A benefit:cost ratio (also known as a Risk Score) based on the jurisdictional financial and reliability benefits and annualized costs of each project is calculated.

From these calculations the projects get prioritized – and based on the capital budget, the projects that will be funded in the current 5-year budget are selected.

Part II reflects all Distribution projects budgeted in the latest/most current available budget (July 2021) at the time of our IDP filing. Budgets are formally updated annually and rebalanced on an ongoing basis. Project scopes and/or timelines are subject to change at any time based on (but not limited to) engineering studies, area considerations, design estimates, permitting feasibility, capital target changes, and emergent circumstances.

Capacity is the only IDP category for which Risk Scores are applicable because it is the only category we have the ability to objectively quantify the annual risk. Capacity projects are driven by feeder and transformer risks that can be quantified in terms of increased reliability. We use the risk score to help prioritize capacity projects; however, as discussed in the system planning Appendix, the risk score is not the only factor used to determine budget priority. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors:

- *Mandates*. Government- or customer-driven work that is covered by our tariffs or involves relocating our facilities in public rights of way when in conflict with road projects, for example. This work category is not negotiable and has established timelines/due dates – and some portion may additionally be emergent in the current year, potentially requiring us to reprioritize/rebalance our budgets.

- *New Business*. Customer-driven work under our tariffs, including customer requests for changes or applications for new service. Like Mandates, this work category is not negotiable, has established timelines/due dates, and some portion may additionally be emergent in the current budget year.

- *Asset Health*. Programs or projects driven by engineering analyses to address aging infrastructure and improve system resilience. Our budget benefit/cost model does not effectively capture the value that a programmatic approach to asset health provides.

- *Blankets*. Blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects and therefore does not lend itself to risk-ranking.

- *Programs*. Also see Asset Health above. Programs are funded based on identified needs or risks outside of the budget risk scoring model. Programmatic work for the current year is typically defined in-year based on equipment failures that are occurring, or after the previous year's reliability results are available and analyzed. For example, our cable replacement program is based on in-year cable failures and customer impacts, and is driven by engineering and reliability needs, not a budgeting risk model. As noted in Asset Health, our budget benefit/cost model does not effectively capture the value that a programmatic engineering approach to cable failures provides.

Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.

Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Part III is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data
2. **Authors:** Electric Systems Performance and the Risk Analytics Department
3. **Importance:** Key values to determine the potential reliability of certain projects
4. **Date the Information was Prepared:** October 29, 2021

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II. CAPACITY RANKINGS

Mitigation Title	Jurisdiction	Lifespan of Project	Total Annualized Costs ($M's)	Reliability Benefit - CMO (Electric)	Financial Benefit	Reliability Benefit	Financial Benefit	Total Weighted Benefit	Project Score
				[PROTECTED DATA BEGINS					
Transfer BLH062 to RSP061	NSPM-ED	40	$0.0049						**62.7**
Load Transfer OSS061-OSS075	NSPM-ED	40	$0.0020						**49.5**
Install Feeder Tie SOU083 to MDT074	NSPM-ED	40	$0.0065						**26.1**
Extend Southtown Feeder SOU087	NSPM-ED	40	$0.0000						**26.0**
SUB MN Feeder Load Monitoring	NSPM-ED	40	$1.9787						**19.2**
Install Feeder Tie SDX312-FSL311	NSPM-ED	40	$0.0000						**9.3**
Extend Woodbury WDY321 for WDY312	NSPM-ED	40	$0.0382						**8.3**
Extend Main Street MST074	NSPM-ED	40	$0.0392						**7.2**
Install Hiawatha West HWW Feeder	NSPM-ED	40	$0.0353						**6.5**
Reinforce Belgrade feeder BEG001	NSPM-ED	50	$0.0031						**5.8**
Install Lake Yankton LAY061 Neutral	NSPM-ED	40	$0.0235						**5.5**
Reinforce Parkers Lake PKL Sub	NSPM-ED	40	$0.0457						**4.7**
Install Stockyards STY TR3	NSPM-ED	40	$0.1910						**4.7**
Install Midtown MDT Feeder	NSPM-ED	40	$0.1775						**4.4**
Install La Crescent LAC TR2	NSPM-ED	40	$0.1510						**4.1**
Reinforce Glenwood GLD Sub Equip	NSPM-ED	40	$0.0432						**4.0**
Reinforce Brooklyn Park BRP062	NSPM-ED	40	$0.0131						**3.0**
Install Feeder Tie EBL064	NSPM-ED	40	$0.0098						**3.0**
Reinforce Kasson KAN TR1	NSPM-ED	40	$0.2231						**2.4**
Reinforce Shepard SHP062 and SHP071	NSPM-ED	40	$0.0418						**2.2**
Reinforce Osseo OSS064	NSPM-ED	40	$0.0111						**2.1**
Reinforce Tracy Switching Station TSS TR01	NSPM-ED	40	$0.2109						**2.1**
Install Southridge SRD212 Fdr	NSPM-ED	40	$0.0863						**2.0**

Reinforce Twin Lakes TWL081	NSPM-ED	40	$0.1307						**1.8**
Reinforce Osseo OSS065	NSPM-ED	40	$0.0738						**1.7**
Install Birch Area Sub	NSPM-ED	40	$0.4823						**1.2**
Extend Main Street Feeder MST066	NSPM-ED	40	$0.0246						**1.1**
Install Feeder Tie ALD081-ALD098	NSPM-ED	40	$0.0233						**1.0**
Install Cannon Falls Trans CTF TR2	NSPM-ED	40	$0.1233						**1.0**
Install Wyoming WYO Feeder	NSPM-ED	40	$0.1670						**1.0**
Extend Saint Louis Park SLP092	NSPM-ED	40	$0.0690						**1.0**
Reinforce Veseli VES TR1	NSPM-ED	40	$0.1697						**0.9**
Reinforce Waseca WAS TR2	NSPM-ED	40	$0.1171						**0.9**
Extend Crooked Lake CRL033	NSPM-ED	40	$0.0817						**0.9**
Reinforce Pine Island TR1	NSPM-ED	40	$0.1171						**0.9**
Install Cottage Grove CGR TR03	NSPM-ED	40	$0.2580						**0.8**
Reinforce Tanners Lake TLK Sub Equip	NSPM-ED	40	$0.0131						**0.8**
Install Viking VKG Feeder	NSPM-ED	40	$0.2521						**0.7**
Extend Southtown Feeder SOU069	NSPM-ED	40	$0.0202						**0.7**
Install East Winona EWI TR2	NSPM-ED	40	$0.2166						**0.7**
Reinforce Basset Creek BCR062	NSPM-ED	40	$0.0163						**0.7**
Install Goodview GVW Feeder	NSPM-ED	40	$0.0678						**0.6**
Reinforce Moore Lake MOL071	NSPM-ED	40	$0.0359						**0.6**
Extend Terminal TER064	NSPM-ED	40	$0.0105						**0.5**
Reinforce Burnside BUR TR2	NSPM-ED	40	$0.1712						**0.4**
Reinforce Ramsey Feeders RAM063 RAM071	NSPM-ED	40	$0.0170						**0.4**
Reinforce Pine Bend PBE TR01	NSPM-ED	40	$0.4059						**0.4**
Install Baytown BYT Feeders	NSPM-ED	40	$0.2662						**0.4**

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Extend Elm Creek ECK322 to WCR	NSPM-ED	40	$0.1183						**0.3**
Reinforce Saint Louis Park SLP087	NSPM-ED	40	$0.0310						**0.3**
Reinforce Terminal TER073	NSPM-ED	40	$0.0719						**0.3**
Install Lindstrom LIN Feeder	NSPM-ED	40	$0.0563						**0.3**
Install Orono ORO TR2 & Feeder	NSPM-ED	40	$0.2725						**0.2**
Install Western WES TR3 & Feeders	NSPM-ED	40	$0.3463						**0.2**
Install Goose Lake GLK TR3	NSPM-ED	40	$0.3668						**0.2**
Install Kohlman Lake KOL Feeder	NSPM-ED	40	$0.2954						**0.2**
Reinforce Edina EDA062	NSPM-ED	40	$0.0327						**0.1**
Reinforce Faribault FAB TR1	NSPM-ED	40	$0.1248						**0.1**
Install Red Rock RRK073	NSPM-ED	40	$0.0536						**0.1**
Reinforce Oakdale OAD073 & OAD075	NSPM-ED	40	$0.0180						**0.1**
Install Zumbrota ZUM TR	NSPM-ED	40	$0.1878						**0.1**
Reinforce Sibley Park SIP Sub Equip	NSPM-ED	40	$0.0065						**0.1**
Reinforce Hyland Lake HYL TRs	NSPM-ED	40	$0.4597						**0.1**
Install Chemolite CHE TR03	NSPM-ED	40	$0.2744						**0.1**
Install Midtown MDT TR2	NSPM-ED	40	$0.2875						**0.0**
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III. Mitigation Calculation Examples

A. Contingency (N-1) Inputs

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B. Overload (N-0) Inputs

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Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.012463	Extend Crooked Lake CRL033	2005.0773	1		0.90			59%	$ 1,250,000
E147.012463	Extend Crooked Lake CRL033	2005.0774	1		0.90			81%	$ 1,250,000
E147.012463	Extend Crooked Lake CRL033	2007.0542	1		0.90			85%	$ 1,250,000
E147.012463	Extend Crooked Lake CRL033	2012.0527	1		0.90			67%	$ 1,250,000
E147.013379	Extend Elm Creek ECK322 to WCR	2010.0935	1		0.29			72%	$ 1,810,000
E147.013379	Extend Elm Creek ECK322 to WCR	2013.0529	1		0.29			57%	$ 1,810,000
E147.013379	Extend Elm Creek ECK322 to WCR	2013.0531	1		0.29			98%	$ 1,810,000
E147.013379	Extend Elm Creek ECK322 to WCR	2013.0532	1		0.29			51%	$ 1,810,000
E141.021662	Extend Main Street Feeder MST066	2020.0278	1		1.13			61%	$ 700,000
E141.017739	Extend Main Street MST074	2017.0160	0		7.16			85%	$ 600,000
E141.019928	Extend Saint Louis Park SLP092	2017.0157	1		0.95			90%	$ 1,056,000
E141.021663	Extend Southtown Feeder SOU069	2020.0309	1		0.70			37%	$ 350,000
E141.021647	Extend Southtown Feeder SOU087	2020.0317	1		26.03			58%	$ 65,000
E141.019955	Extend Terminal TER064	2020.0319	1		0.52			60%	$ 161,000
E150.020609	Extend Woodbury WDY321 for WDY312	2021.0130	1		8.33			83%	$ 584,000
E156.015749	Install Baytown BYT Feeders	2013.0135	1		0.35			85%	$ 4,200,000
E156.015749	Install Baytown BYT Feeders	2016.0167	1		0.35			69%	$ 4,200,000
E156.011874	Install Birch Area Sub	2010.0181	1		1.23			74%	$ 7,610,078
E156.011874	Install Birch Area Sub	2010.0180	1		1.23			85%	$ 7,610,078
E156.011874	Install Birch Area Sub	2013.0062	1		1.23			76%	$ 7,610,078
E144.008708	Install Cannon Falls Trans CTF TR2	2007.0757	1		1.04			113%	$ 1,995,000
E144.008708	Install Cannon Falls Trans CTF TR2	2013.1534	0		1.04			113%	$ 1,995,000
E144.008708	Install Cannon Falls Trans CTF TR2	2005.0386	1		1.04			96%	$ 1,995,000
E144.008708	Install Cannon Falls Trans CTF TR2	2022.0077	1		1.04			74%	$ 1,995,000
E144.008708	Install Cannon Falls Trans CTF TR2	2022.0078	1		1.04			47%	$ 1,995,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E150.021672	Install Chemolite CHE TR03	2018.0094	1		0.06			56%	$ 4,200,000
E150.021672	Install Chemolite CHE TR03	2021.0094	1		0.06			66%	$ 4,200,000
E150.021672	Install Chemolite CHE TR03	2021.0095	1		0.06			58%	$ 4,200,000
E150.021672	Install Chemolite CHE TR03	2021.0096	1		0.06			97%	$ 4,200,000
E150.021672	Install Chemolite CHE TR03	2021.0097	1		0.06			61%	$ 4,200,000
E150.021670	Install Cottage Grove CGR TR03	2021.0365	1		0.80			78%	$ 4,200,000
E150.021670	Install Cottage Grove CGR TR03	2021.0366	1		0.80			77%	$ 4,200,000
E150.021670	Install Cottage Grove CGR TR03	2021.0371	1		0.80			83%	$ 4,200,000
E150.021670	Install Cottage Grove CGR TR03	2019.0082	0		0.80			111%	$ 4,200,000
E144.013520	Install East Winona EWI TR2	2019.0083	0		0.67			112%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2005.0562	1		0.67			78%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2008.1123	1		0.67			78%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2008.1152	1		0.67			57%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2014.0080	1		0.67			65%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2014.0081	1		0.67			91%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2014.0082	1		0.67			66%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2014.0084	1		0.67			104%	$ 3,200,000
E144.013520	Install East Winona EWI TR2	2014.0087	0		0.67			104%	$ 3,200,000
E141.020663	Install Feeder Tie ALD081-ALD098	2020.0217	1		1.04			94%	$ 356,000
E143.016727	Install Feeder Tie EBL064	2016.0363	1		2.97			87%	$ 150,000
E143.016727	Install Feeder Tie EBL064	2016.0367	1		2.97			36%	$ 150,000
E154.021667	Install Feeder Tie SDX312-FSL311	2020.0501	1		9.32			53%	$ 750,000
E154.021667	Install Feeder Tie SDX312-FSL311	2021.0580	1		9.32			40%	$ 750,000
E141.019930	Install Feeder Tie SOU083 to MDT074	2020.0314	1		26.07			57%	$ 100,000
E144.002712	Install Goodview GVW Feeder	2004.0808	1		0.62			112%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2004.0812	1		0.62			78%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2009.0875	1		0.62			71%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2009.0877	1		0.62			91%	$ 1,100,000
E156.007927	Install Goose Lake GLK TR3	2005.0554	1		0.20			75%	$ 5,260,000
E156.007927	Install Goose Lake GLK TR3	2005.0555	1		0.20			74%	$ 5,260,000
E156.007927	Install Goose Lake GLK TR3	2012.0560	1		0.20			82%	$ 5,260,000
E156.007927	Install Goose Lake GLK TR3	2013.0109	1		0.20			88%	$ 5,260,000
E156.007927	Install Goose Lake GLK TR3	2013.0110	1		0.20			73%	$ 5,260,000
E156.007927	Install Goose Lake GLK TR3	2013.0113	1		0.20			79%	$ 5,260,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E156.007927	Install Goose Lake GLK TR3	2013.0114	1		0.20			68%	$ 5,260,000
E156.007927	Install Goose Lake GLK TR3	2013.0116	1		0.20			87%	$ 5,260,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0233	1		6.49			94%	$ 540,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0248	1		6.49			66%	$ 540,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0249	1		6.49			63%	$ 540,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0251	1		6.49			98%	$ 540,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0345	1		6.49			64%	$ 540,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0346	1		6.49			51%	$ 540,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0563	1		0.16			90%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2021.0036	0		0.16			90%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2007.0784	1		0.16			91%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2008.0733	1		0.16			62%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0561	1		0.16			37%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0562	1		0.16			69%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0564	1		0.16			57%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0565	1		0.16			97%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2014.0455	1		0.16			66%	$ 4,520,000
E156.010177	Install Kohlman Lake KOL Feeder	2014.0456	1		0.16			42%	$ 4,520,000
E144.000791	Install La Crescent LAC TR2	2005.0430	1		4.14			95%	$ 2,210,000
E144.000791	Install La Crescent LAC TR2	2004.1112	1		4.14			78%	$ 2,210,000
E144.000791	Install La Crescent LAC TR2	2005.0429	1		4.14			109%	$ 2,210,000
E144.000791	Install La Crescent LAC TR2	2022.0082	0		4.14			109%	$ 2,210,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E152.020732	Install Lake Yankton LAY061 Neutral	2021.0166	1		5.49			37%	$ 360,000
E156.011752	Install Lindstrom LIN Feeder	2005.0568	1		0.27			89%	$ 862,000
E156.011752	Install Lindstrom LIN Feeder	2006.0210	1		0.27			54%	$ 862,000
E156.011752	Install Lindstrom LIN Feeder	2006.0211	1		0.27			96%	$ 862,000
E156.011752	Install Lindstrom LIN Feeder	2008.0856	1		0.27			92%	$ 862,000
E141.019929	Install Midtown MDT Feeder	2017.0541	1		4.40			107%	$ 2,716,000
E141.019929	Install Midtown MDT Feeder	2020.0331	0		4.40			107%	$ 2,716,000
E141.019929	Install Midtown MDT Feeder	2020.0211	1		4.40			82%	$ 2,716,000
E141.019929	Install Midtown MDT Feeder	2020.0212	1		4.40			96%	$ 2,716,000
E141.019929	Install Midtown MDT Feeder	2020.0304	1		4.40			90%	$ 2,716,000
E141.019929	Install Midtown MDT Feeder	2020.0347	1		4.40			102%	$ 2,716,000
E141.019929	Install Midtown MDT Feeder	2020.0332	0		4.40			112%	$ 2,716,000
E141.009145	Install Midtown MDT TR2	2008.1458	1		0.02			69%	$ 4,400,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0539	1		0.22			56%	$ 4,100,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0766	1		0.22			62%	$ 4,100,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.1699	1		0.22			82%	$ 4,100,000
E150.020608	Install Red Rock RRK073	2013.1457	1		0.11			75%	$ 928,000
E152.020733	Install Southridge SRD212 Fdr	2021.0167	1		2.03			100%	$ 1,370,000
E152.020733	Install Southridge SRD212 Fdr	2021.0142	0		2.03			100%	$ 1,370,000
E143.017702	Install Viking VKG Feeder	2016.0418	1		0.71			51%	$ 4,100,000
E143.017702	Install Viking VKG Feeder	2016.0564	1		0.71			99%	$ 4,100,000
E143.017702	Install Viking VKG Feeder	2016.0376	0		0.71			99%	$ 4,100,000
E143.017702	Install Viking VKG Feeder	2017.0452	1		0.71			102%	$ 4,100,000
E143.017702	Install Viking VKG Feeder	2017.0451	0		0.71			102%	$ 4,100,000
E151.012409	Install Western WES TR3 & Feeders	2005.0139	1		0.20			83%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2006.1178	1		0.20			91%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2007.1177	1		0.20			102%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2008.0203	1		0.20			92%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2010.0320	1		0.20			85%	$ 5,300,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E151.012409	Install Western WES TR3 & Feeders	2010.0342	1		0.20			83%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2013.0167	1		0.20			56%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2013.0168	1		0.20			66%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2013.1524	1		0.20			84%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2013.1525	1		0.20			84%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2013.1528	1		0.20			98%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2008.0202	1		0.20			93%	$ 5,300,000
E151.012409	Install Western WES TR3 & Feeders	2013.0160	0		0.20			93%	$ 5,300,000
E156.011061	Install Wyoming WYO Feeder	2004.1268	1		0.99			73%	$ 2,606,000
E156.011061	Install Wyoming WYO Feeder	2005.0720	1		0.99			97%	$ 2,606,000
E156.011061	Install Wyoming WYO Feeder	2006.0229	1		0.99			78%	$ 2,606,000
E156.011061	Install Wyoming WYO Feeder	2010.0166	1		0.99			95%	$ 2,606,000
E156.011061	Install Wyoming WYO Feeder	2011.0158	1		0.99			62%	$ 2,606,000
E144.000793	Install Zumbrota ZUM TR	2004.1114	1		0.10			99%	$ 3,050,000
E144.000793	Install Zumbrota ZUM TR	2011.0097	1		0.10			48%	$ 3,050,000
E147.021613	Load Transfer OSS061-OSS075	2021.0395	0		49.45			111%	$ 30,000
E147.019056	Reinforce Basset Creek BCR062	2013.0546	1		0.67			88%	$ 250,000
E147.019056	Reinforce Basset Creek BCR062	2018.0948	0		0.67			93%	$ 250,000
E154.020557	Reinforce Belgrade feeder BEG001	2011.0425	0		5.81			110%	$ 50,000
E147.014465	Reinforce Brooklyn Park BRP062	2012.0512	1		2.98			80%	$ 200,000
E144.010920	Reinforce Burnside BUR TR2	2005.0433	1		0.44			86%	$ 2,700,000
E144.010920	Reinforce Burnside BUR TR2	2006.0285	1		0.44			30%	$ 2,700,000
E144.010920	Reinforce Burnside BUR TR2	2009.0884	1		0.44			80%	$ 2,700,000
E143.019054	Reinforce Edina EDA062	2016.0385	1		0.13			94%	$ 500,000
E143.019054	Reinforce Edina EDA062	2016.0386	1		0.13			70%	$ 500,000
E144.020614	Reinforce Faribault FAB TR1	2005.0479	1		0.12			94%	$ 2,025,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E154.018960	Reinforce Glenwood GLD Sub Equip	2005.0076	1		3.97			94%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2009.0358	1		3.97			83%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2012.0131	1		3.97			37%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2018.0825	1		3.97			75%	$ 700,000
E143.019908	Reinforce Hyland Lake HYL TRs	2018.0913	1		0.09			67%	$ 7,000,000
E143.019908	Reinforce Hyland Lake HYL TRs	2018.0917	1		0.09			86%	$ 7,000,000
E143.019908	Reinforce Hyland Lake HYL TRs	2018.0932	1		0.09			85%	$ 7,000,000
E143.019908	Reinforce Hyland Lake HYL TRs	2020.0165	1		0.09			99%	$ 7,000,000
E143.019908	Reinforce Hyland Lake HYL TRs	2020.0166	1		0.09			59%	$ 7,000,000
E144.013436	Reinforce Kasson KAN TR1	2007.0706	1		2.41			111%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2019.0012	0		2.41			111%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2007.0707	1		2.41			56%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2008.0398	1		2.41			90%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2011.0111	1		2.41			79%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2022.0090	1		2.41			53%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2005.0758	1		2.41			106%	$ 3,064,000
E144.013436	Reinforce Kasson KAN TR1	2013.0155	0		2.41			106%	$ 3,064,000
E141.019958	Reinforce Moore Lake MOL071	2020.0351	1		0.55			81%	$ 550,000
E156.015811	Reinforce Oakdale OAD073 & OAD075	2012.0572	1		0.11			59%	$ 275,004
E147.021595	Reinforce Osseo OSS064	2012.0538	1		2.07			53%	$ 180,000
E147.021595	Reinforce Osseo OSS064	2012.0539	1		2.07			111%	$ 180,000
E147.021595	Reinforce Osseo OSS064	2021.0398	0		2.07			105%	$ 180,000
E147.021614	Reinforce Osseo OSS065	2012.0536	1		1.69			86%	$ 1,130,000
E147.021614	Reinforce Osseo OSS065	2012.0541	1		1.69			68%	$ 1,130,000
E147.021614	Reinforce Osseo OSS065	2021.0435	1		1.69			66%	$ 1,130,000
E147.021629	Reinforce Parkers Lake PKL Sub	2021.0447	1		4.69			69%	$ 700,000
E147.021629	Reinforce Parkers Lake PKL Sub	2005.0781	1		4.69			84%	$ 700,000
E147.021629	Reinforce Parkers Lake PKL Sub	2006.0132	1		4.69			84%	$ 700,000
E147.021629	Reinforce Parkers Lake PKL Sub	2013.0543	1		4.69			93%	$ 700,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.021629	Reinforce Parkers Lake PKL Sub	2014.0335	1		4.69			57%	$ 700,000
E150.021635	Reinforce Pine Bend PBE TR01	2021.0417	1		0.36			73%	$ 4,500,000
E150.021635	Reinforce Pine Bend PBE TR01	2021.0418	1		0.36			72%	$ 4,500,000
E150.021635	Reinforce Pine Bend PBE TR01	2021.0419	1		0.36			72%	$ 4,500,000
E144.010889	Reinforce Pine Island TR1	2005.0728	1		0.87			79%	$ 1,900,000
E144.010889	Reinforce Pine Island TR1	2007.0715	1		0.87			92%	$ 1,900,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2006.0206	1		0.41			66%	$ 260,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2014.0458	1		0.41			64%	$ 260,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2014.0459	1		0.41			68%	$ 260,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2014.0460	1		0.41			72%	$ 260,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2016.0288	1		0.41			74%	$ 260,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2016.0289	1		0.41			67%	$ 260,000
E141.019954	Reinforce Saint Louis Park SLP087	2020.0293	1		0.28			103%	$ 475,002
E151.020596	Reinforce Shepard SHP062 and SHP071	2010.0329	1		2.24			98%	$ 640,000
E151.020596	Reinforce Shepard SHP062 and SHP071	2013.1521	1		2.24			102%	$ 640,000
E144.016592	Reinforce Sibley Park SIP Sub Equip	2018.0091	1		0.10			82%	$ 100,000
E144.016592	Reinforce Sibley Park SIP Sub Equip	2018.0092	1		0.10			67%	$ 100,000
E150.010914	Install Stockyards STY TR3	2013.1451	1		4.65			97%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2005.1672	1		4.65			63%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2005.1713	1		4.65			99%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2005.1715	1		4.65			76%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2007.0281	1		4.65			99%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2007.0282	1		4.65			65%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2008.0350	1		4.65			67%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2008.0374	1		4.65			105%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2008.1187	1		4.65			66%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2011.0091	1		4.65			118%	$ 2,925,000

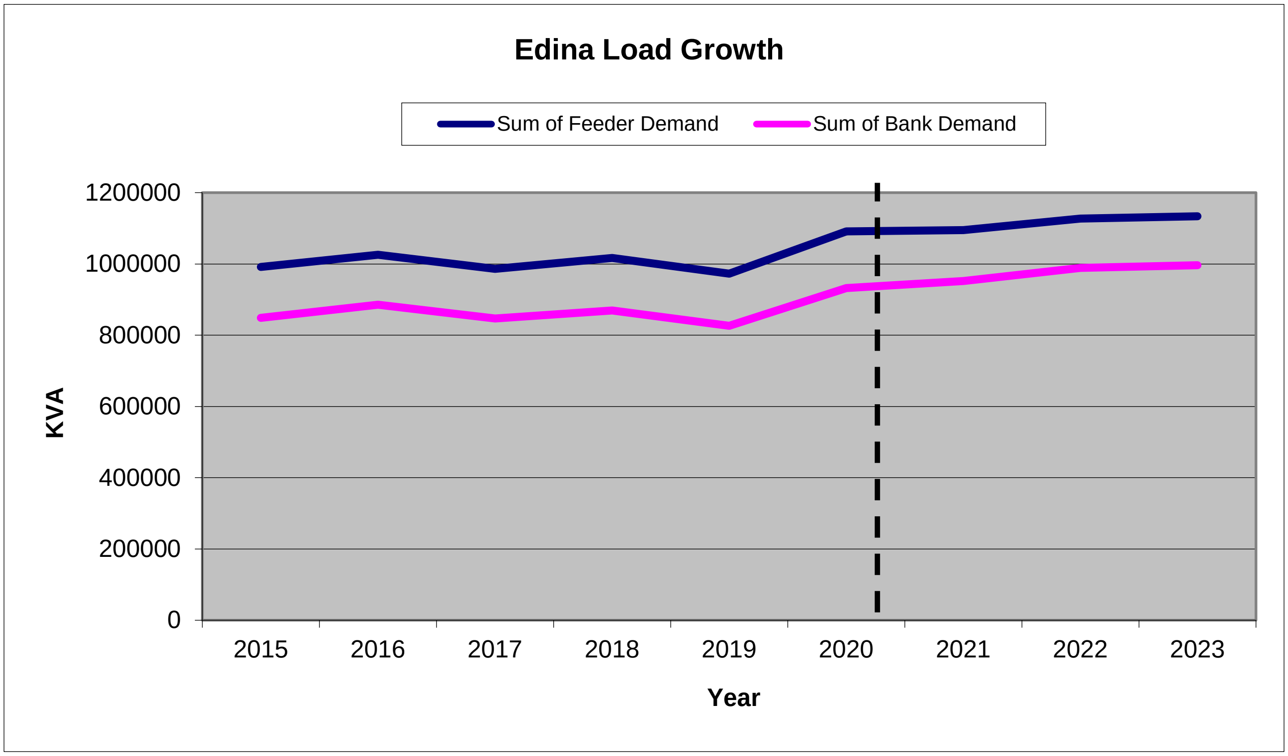
PROTECTED DATA SHADED

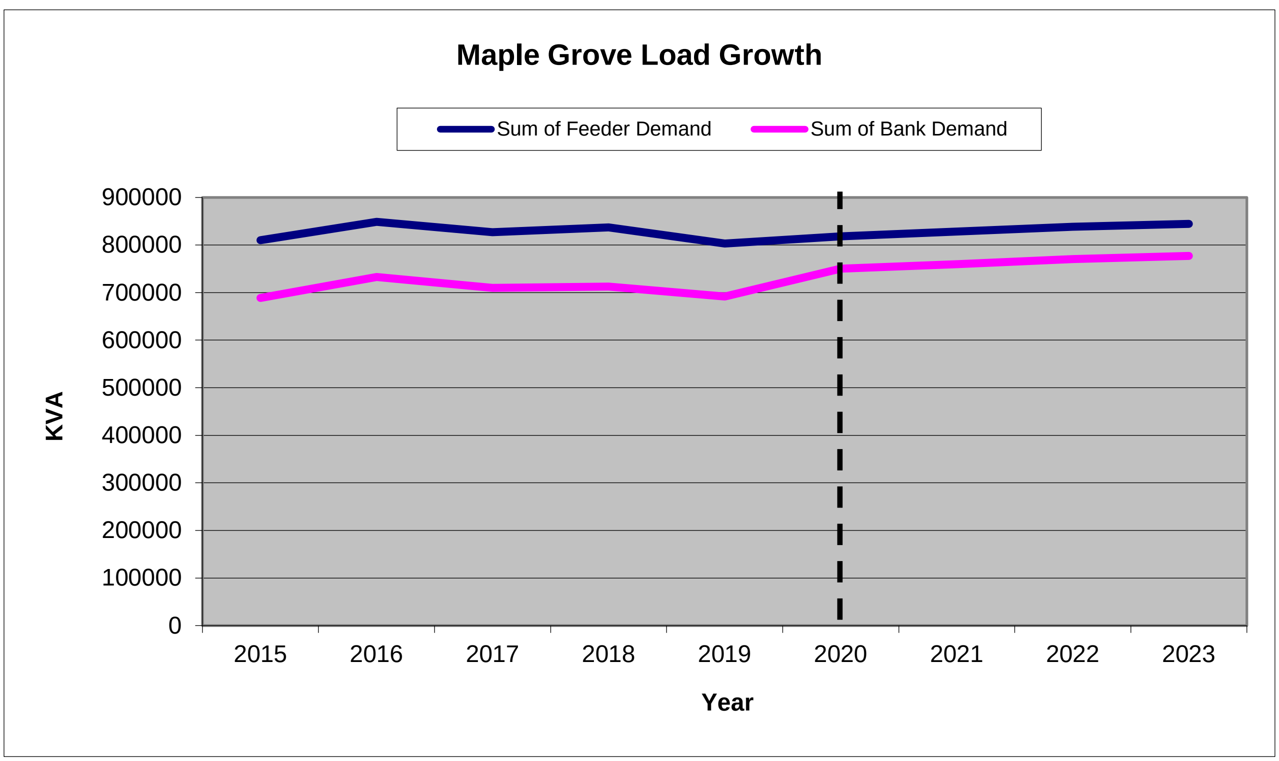
Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2021 Forecasted Demand kVA	2021 Forecasted Capacity kVA	2021 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E150.010914	Install Stockyards STY TR3	2018.0022	0		4.65			118%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2013.1453	1		4.65			65%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2005.1714	1		4.65			134%	$ 2,925,000
E150.010914	Install Stockyards STY TR3	2013.0131	0		4.65			134%	$ 2,925,000
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2009.0399	1		0.80			57%	$ 200,000
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2011.0177	1		0.80			70%	$ 200,000
E141.019956	Reinforce Terminal TER073	2020.0340	1		0.27			72%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0342	1		0.27			65%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0343	1		0.27			83%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0283	1		0.27			85%	$ 1,100,000
E152.020734	Reinforce Tracy Switching Station TSS TR01	2012.0602	1		2.07			91%	$ 3,000,000
E152.020734	Reinforce Tracy Switching Station TSS TR01	2020.0138	1		2.07			97%	$ 3,000,000
E152.020734	Reinforce Tracy Switching Station TSS TR01	2020.0139	1		2.07			60%	$ 3,000,000
E152.020734	Reinforce Tracy Switching Station TSS TR01	2020.0140	1		2.07			56%	$ 3,000,000
E152.020734	Reinforce Tracy Switching Station TSS TR01	2021.0144	0		2.07			119%	$ 3,000,000
E147.016682	Reinforce Twin Lakes TWL081	2007.0556	1		1.75			74%	$ 2,000,000
E147.016682	Reinforce Twin Lakes TWL081	2014.0486	1		1.75			77%	$ 2,000,000
E147.016682	Reinforce Twin Lakes TWL081	2016.0529	1		1.75			63%	$ 2,000,000
E147.016682	Reinforce Twin Lakes TWL081	2012.0531	1		1.75			108%	$ 2,000,000
E147.016682	Reinforce Twin Lakes TWL081	2021.0396	0		1.75			108%	$ 2,000,000
E147.016682	Reinforce Twin Lakes TWL081	2017.0085	1		1.75			103%	$ 2,000,000
E147.016682	Reinforce Twin Lakes TWL081	2017.0084	0		1.75			103%	$ 2,000,000
E144.018971	Reinforce Veseli VES TR1	2008.0365	1		0.93			0%	$ 2,750,000
E144.018971	Reinforce Veseli VES TR1	2013.1491	1		0.93			82%	$ 2,750,000
E144.013446	Reinforce Waseca WAS TR2	2014.0159	1		0.90			60%	$ 1,900,000
E144.013446	Reinforce Waseca WAS TR2	2014.0160	1		0.90			82%	$ 1,900,000
E154.021656	Transfer BLH062 to RSP061	2020.0796	0		62.69			116%	$ 75,000

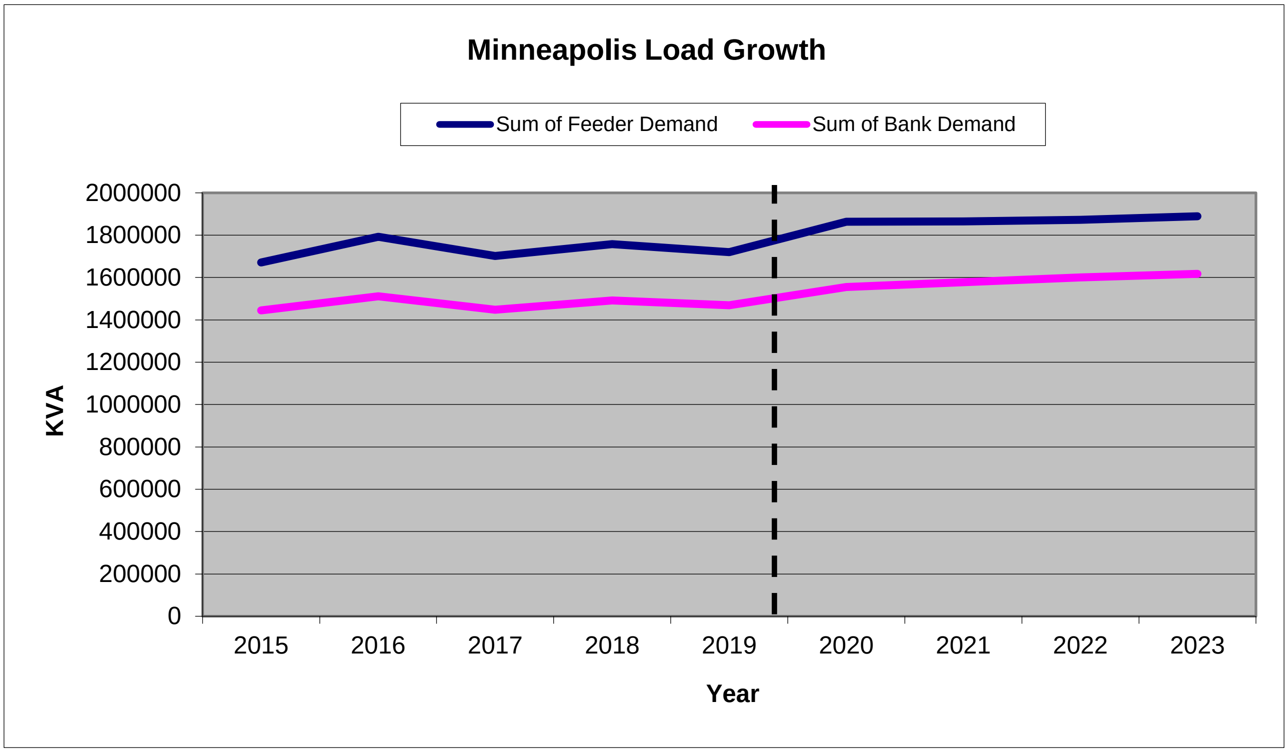
PROTECTED DATA ENDS]

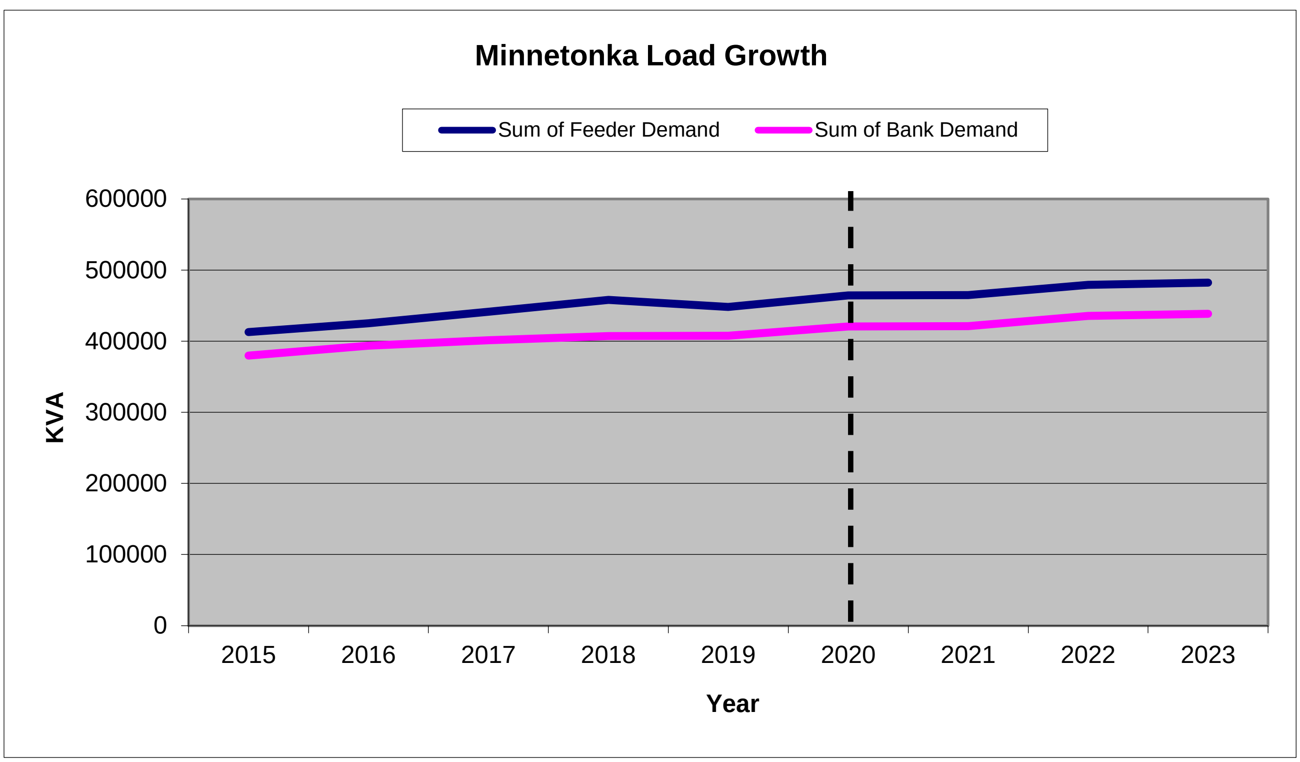
Protected Data Justification

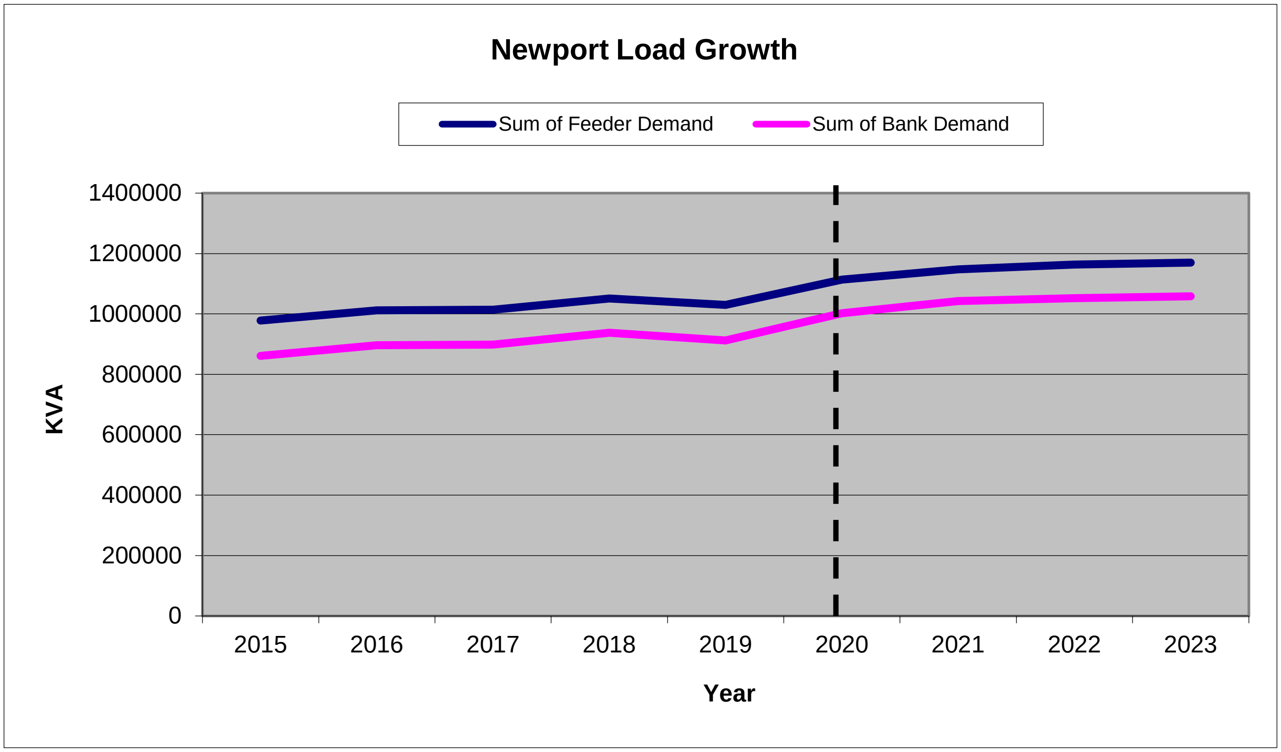
The shaded and marked columns in this spreadsheet contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

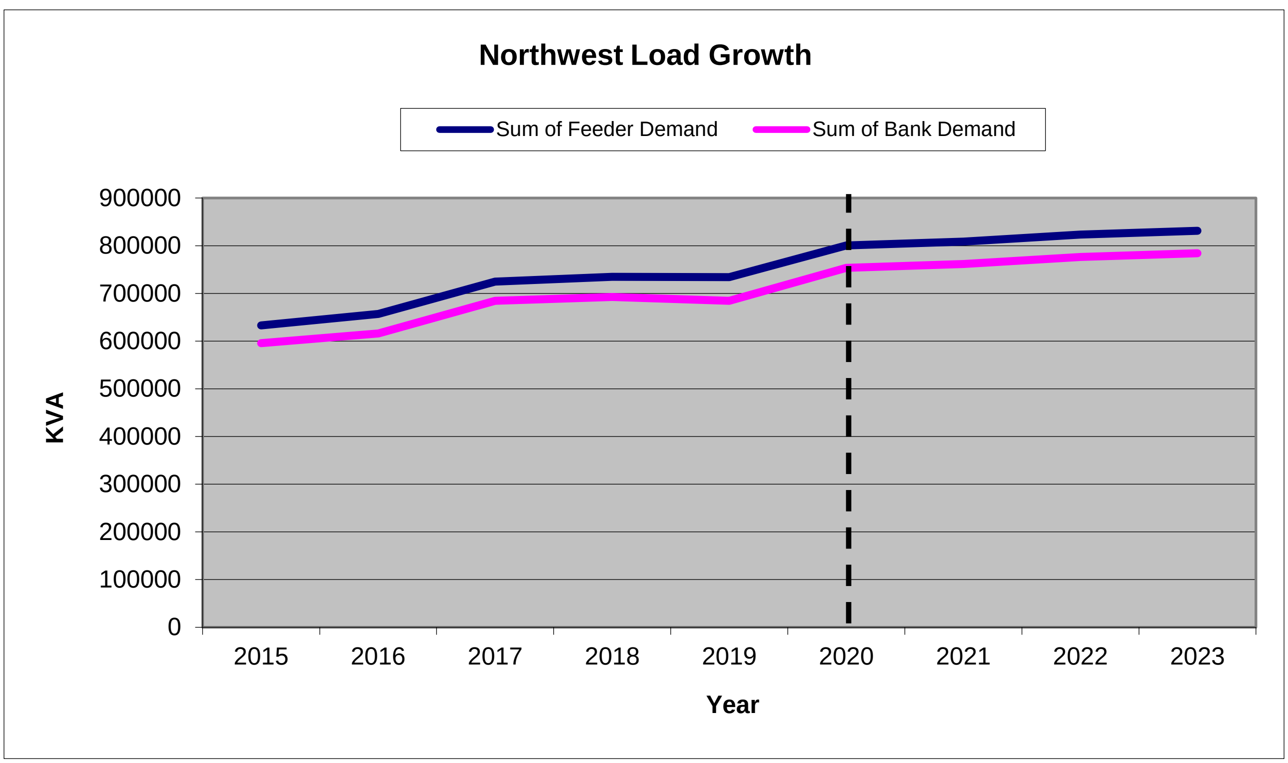

Edina Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
1200000
1000000
800000
600000
400000
200000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year

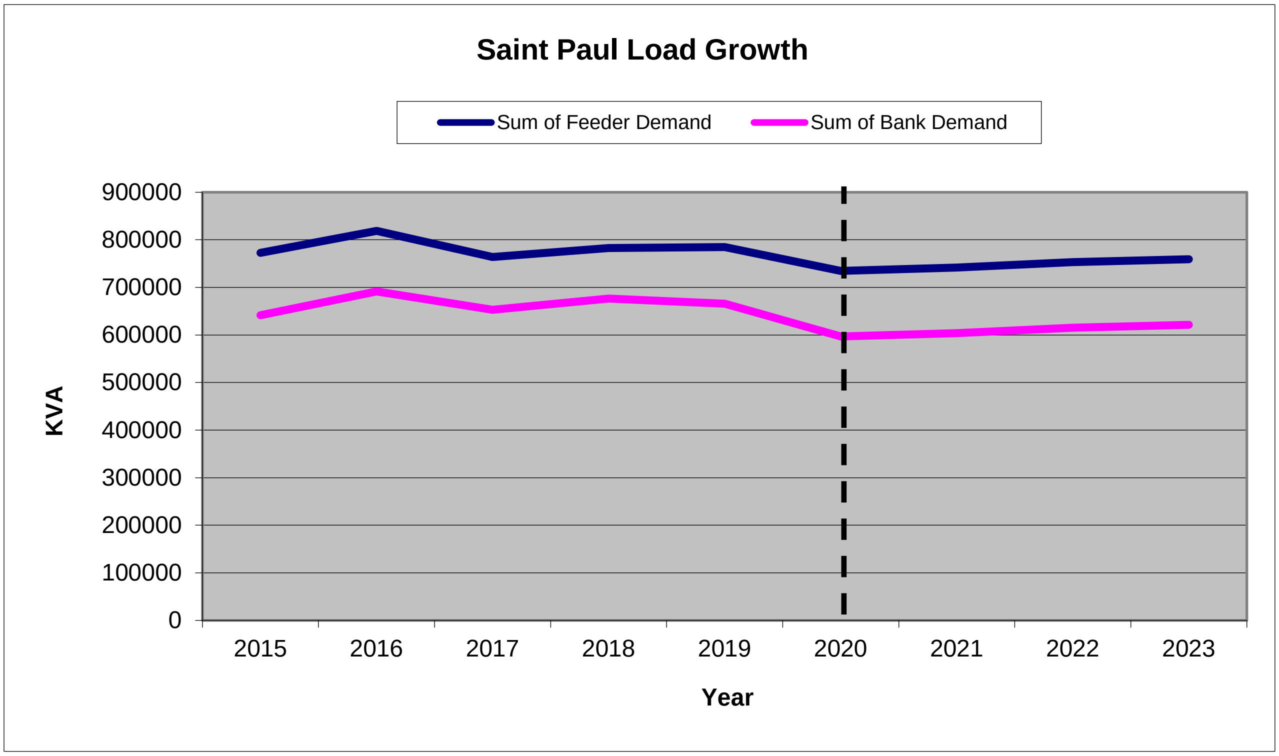

Maple Grove Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year

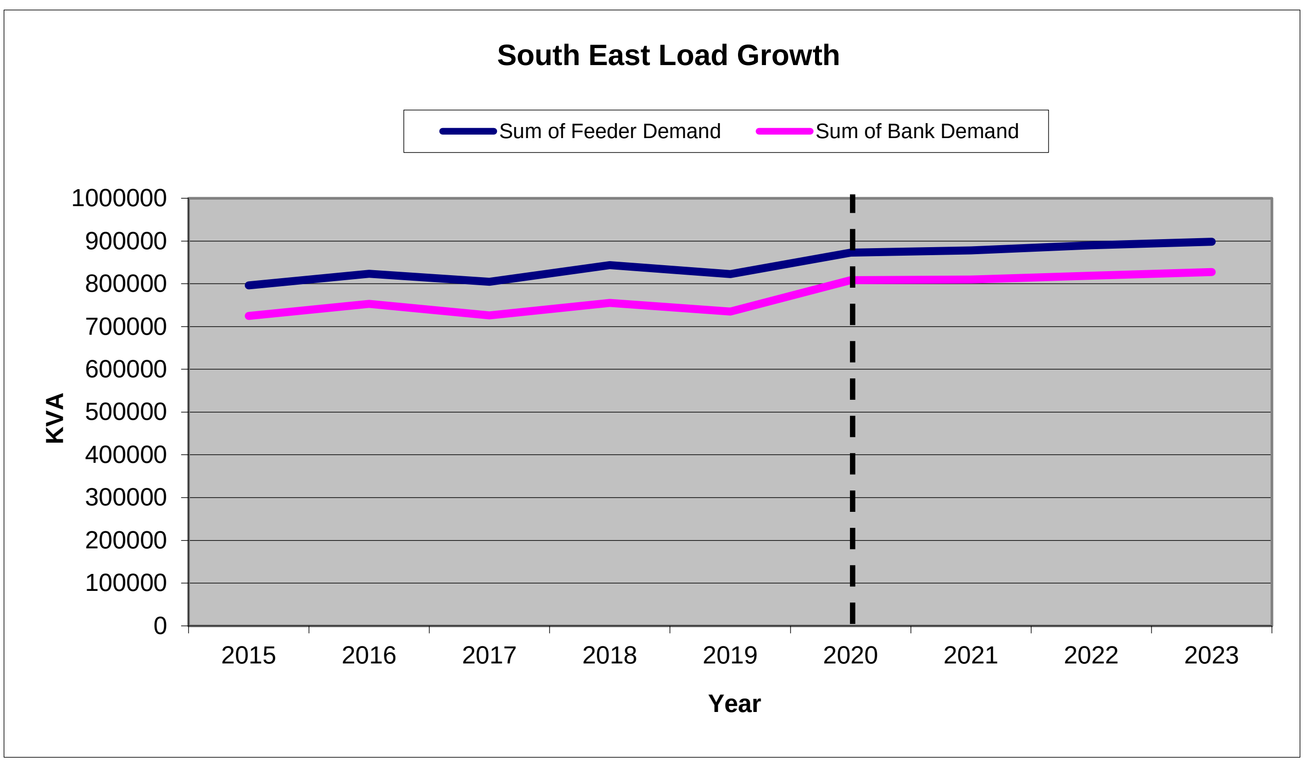

Minneapolis Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
2000000
1800000
1600000
1400000
1200000
1000000
800000
600000
400000
200000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year

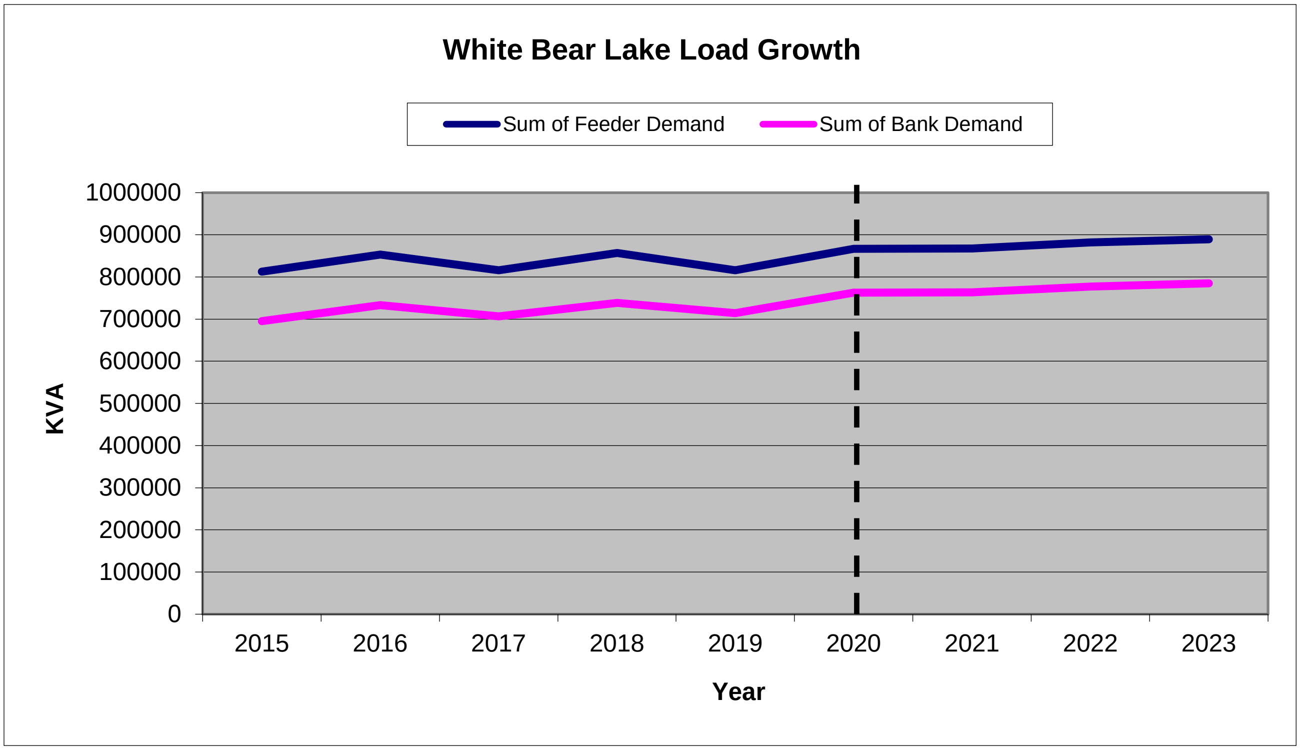

Minnetonka Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
600000
500000
400000
300000
200000
100000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year


Newport Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
1400000
1200000
1000000
800000
600000
400000
200000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year


Northwest Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year


Saint Paul Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year


South East Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
1000000
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year


White Bear Lake Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
1000000
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year

IDP Requirement 3.D.2 requires that we provide:

Impacts to net present value of system costs (in NPV RR/MWh or MW)

As we have noted in our past IDPs, we understand this requirement to be a calculation similar to that provided in conjunction with an Integrated Resource Plan. We continue to believe there are differing characteristics associated with the distribution system that make this complex to translate. That said, we have not been provided other direction, so provide a distribution-level calculation consistent with what we have provided in the past.

Our approach is similar to a jurisdictional cost of service – but for just the Distribution function of the Company. In general, a jurisdictional cost of service study includes the following financial data input sections: (1) capital structure; (2) cost of capital; (3) income tax rates; (4) rate base; (5) income statement; (6) income tax calculations; and (7) cash working capital computation.

We clarify that this "rate base" view of the Distribution function will not match the budget information we provide in this IDP, because the inputs to the NPV Revenue Requirements (RR) calculation are specific to just the distribution system located in Minnesota. As such, only costs that are direct-assigned to Distribution, and distribution assets located in the state of Minnesota are included. Common and general property in support of the Distribution function are not included in this view – but are represented in the distribution budget information provided elsewhere in this IDP. Similarly, other rate base is not included, and we are not including ratemaking treatments such as net operating losses.

Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital. It is generally comprised of the following major items:

- *Net Utility Plant.* Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.
- *Construction Work in Progress (CWIP).* In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.
- *Accumulated Deferred Income Taxes (ADIT).* Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in

one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation generally exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

- *Pre-Funded Allowance for Funds Used During Construction (AFUDC).* In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in service, the recording of AFUDC ceases and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.

- *Other Rate Base.* Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. In general, it includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities.

Rate base is generally calculated as outlined in Table 1 below.

Table 1: High Level Rate Base Calculation

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve
Less:	Average Accumulated Provision for Deferred Taxes
Plus:	Average Construction Work in Progress
Plus:	Average Working Capital
Equals:	Rate Base

For this Distribution Function NPV RR, we calculated the growth in revenue requirements over the 5-year budget period to derive an NPV of $271.9 million (in 2021 dollars).

	Annual Revenue Requirement						
	Electric Distribution Minnesota						
	2021-2026						
	(000's)						
	Rate Analysis	2021	2022	2023	2024	2025	2026
1	Average Balances:						
2	Plant Investment	4,101,451	4,430,905	4,873,407	5,343,893	5,776,023	6,184,761
3	Depreciation Reserve	1,489,744	1,563,357	1,650,864	1,757,016	1,881,581	2,021,828
4	CWIP	45,796	52,628	71,083	72,695	77,511	83,138
5	Accumulated Deferred Taxes	589,159	595,506	608,518	616,032	623,193	632,090
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	2,068,343	2,324,670	2,685,108	3,043,541	3,348,759	3,613,980
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53						
10							
11	Expenses:						
12	Book Depreciation	119,218	132,423	152,785	172,069	188,959	204,367
13	Annual Deferred Tax	(5,399)	18,093	7,932	7,095	7,229	10,566
14	ITC Flow Thru	(268)	(267)	(264)	(256)	(242)	(222)
15	Property Taxes	53,824	60,030	67,330	74,950	82,026	89,416
16	subtotal expense = lines 12 thru 15	167,375	210,278	227,784	253,859	277,972	304,127
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	116,565	215,622	199,306	217,198	122,042	115,014
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	2,400	2,505	2,461	2,799	-	-
22							
23	AFUDC	4,158	3,897	3,606	4,175	3,800	4,134
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	40,333	45,331	51,554	59,045	63,961	67,943
27	Equity Return = line 6 x (line 46 + line 47)	111,277	124,602	143,922	163,134	179,493	193,709
28							
29	Tax Calculations:						
30	Equity Return = line 27	111,277	124,602	143,922	163,134	179,493	193,709
31	Taxable Expenses = lines 12 thru 14	113,551	150,248	160,454	178,909	195,946	214,711
32	plus Tax Additions = line 21	2,400	2,505	2,461	2,799	-	-
33	less Tax Deductions = (line 19 + line 23)	(120,723)	(219,518)	(202,912)	(221,373)	(125,842)	(119,148)
34	subtotal	106,504	57,838	103,924	123,469	249,597	289,272
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	42,958	23,329	41,918	49,801	100,675	116,678
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	42,958	23,329	41,918	49,801	100,675	116,678
39							
40	Total Capital Revenue Requirements	357,785	399,644	461,572	521,664	618,301	678,323
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	110,623	120,803	126,532	128,391	126,854	128,033
43	Total Revenue Requirements	468,408	520,447	588,103	650,054	745,156	806,356
	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**1.9500%**	**1.9400%**	**1.9100%**	**1.9300%**	**1.9000%**	**1.8700%**
45	**Short Term Debt**	**0.0000%**	**0.0100%**	**0.0100%**	**0.0100%**	**0.0100%**	**0.0100%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3800%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**
48	**Required Rate of Return**	**7.3300%**	**7.3100%**	**7.2800%**	**7.3000%**	**7.2700%**	**7.2400%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
52	Growth in Total Revenue Requirements	-	52,039	67,656	61,951	95,101	61,201
53	Present Value of Growth in Total Revenue Requirements	271,954					

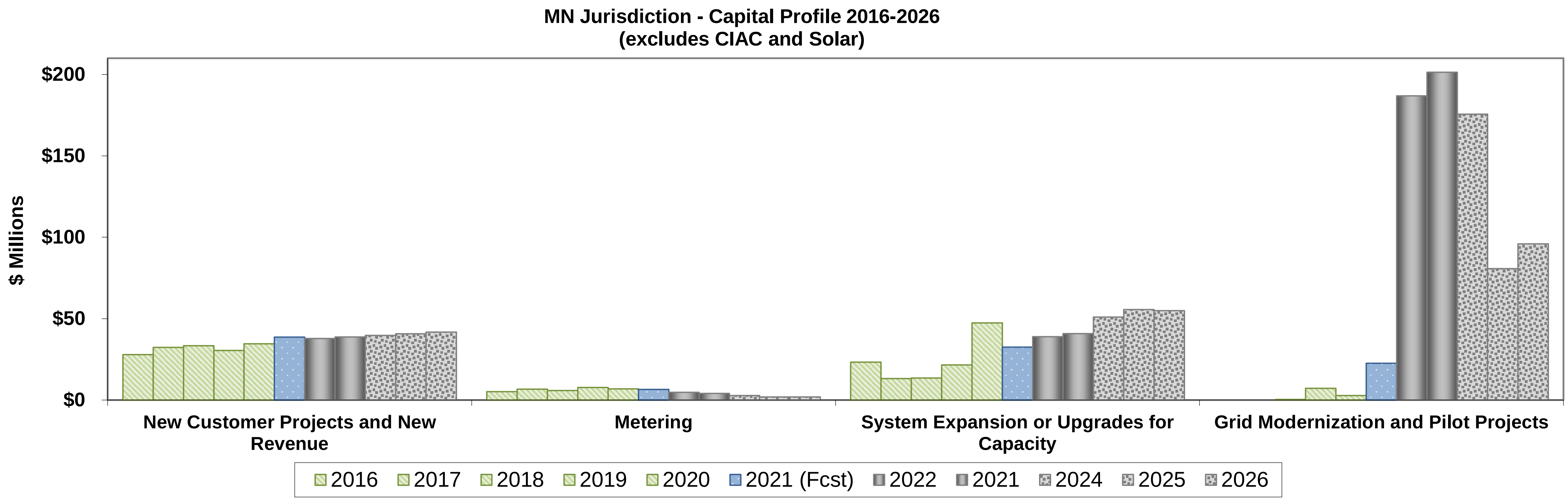
	Mitigation	Mitigation Name	Risk Score	2021	2022	2023	2024	2025	Grand Total
Age-Related Replacements and Asset Renewal				**144,347,399**	**167,254,638**	**173,346,712**	**185,505,780**	**189,622,879**	**860,077,408**
Routines	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	NA	20,443,000	20,947,000	21,464,000	22,024,000	22,618,000	107,496,000
	E114.018274	MN - UG Conversion/Rebuild Blanket	NA	5,670,000	5,810,000	5,953,004	6,108,000	6,273,004	29,814,008
	E114.018275	MN - UG Services Renewal Blanket	NA	5,126,000	5,252,000	5,382,000	5,522,000	5,671,004	26,953,004
	E114.018354	MN - OH Street Light Rebuild Blanket	NA	1,551,000	1,589,000	1,628,000	1,670,000	1,715,004	8,153,004
	E114.018355	MN - UG Street Light Rebuild Blanket	NA	1,468,000	1,504,000	1,541,004	1,581,004	1,624,000	7,718,008
	E114.018178	MN - OH Services Renewal Blanket	NA	760,000	779,000	798,000	819,000	841,000	3,997,000
	E141.017359	MPLS UG Network Vault Blanket	NA	500,000	500,000	500,000	500,000	500,000	2,500,000
	E151.016697	STP UG Network Vault Blanket	NA	250,000	250,000	250,000	250,000	250,000	1,250,000
Discrete	E151.020871	Relocate STP Tunnel Feeders	NA	2,000,000	5,000,000	5,000,000	5,000,000	5,000,000	22,000,000
	E151.020897	Reinforce Daytons Bluff DBL Substation	NA	4,400,000	11,700,000	3,800,000			19,900,000
	E141.017673	Aldrich Mitigation	NA			4,000,000	4,000,000	4,000,000	12,000,000
	E144.017589	Rebuild Yellow Medicine YLM211 & YLM212	NA	800,000	1,000,000	1,000,000	1,900,000		4,700,000
	E154.019464	T Rebuild West St Cloud to Millwood	NA	3,000,000	1,500,000				4,500,000
	E151.020496	Rebuild Downtown St. Paul Manholes	NA	2,200,000	2,200,000				4,400,000
	E144.021748	ELR Install Gaiter Lake Sub	NA	150,000	1,150,000	2,650,000	300,000		4,250,000
	E144.013600	Convert Butterfield BTF 4kV	NA	500,000	2,200,000				2,700,000
	E154.013633	Convert Hector HEC 4kV	NA				100,000	2,400,000	2,500,000
	E144.018411	Rebuild Clara City CLC221	NA		1,000,000	1,100,000			2,100,000
	E144.013622	Convert Lafayette LAF 4kV	NA			100,000	1,950,000		2,050,000
	E144.019617	Rebuild Sacred Heart SCH211	NA	1,100,000					1,100,000
	E154.021722	T Rebuild ALB-PAT-WAK Underbuild	NA	300,000	300,000				600,000
	E154.021436	T Underbuild Brooten to Paynesville	NA	396,000					396,000
	E147.020898	T Replace Coon Creek CNC Relays	NA	190,000					190,000
Failure Related	E103.001736	MN Failed Sub Equip Replacement	NA	3,300,000	3,399,000	3,500,961	3,607,000	3,716,000	17,522,961
	E103.016837	MN Failed Sub TR Replacement	NA	2,000,000	2,060,000	2,122,000	2,186,000	2,252,000	10,620,000
	E103.020681	Reserve TR 115/13.8 kV 50 MVA	NA	100,000	900,000				1,000,000
	E103.021701	Reserve TR 115/13.8 kV 50 MVA	NA	900,000					900,000
	E103.012618	Reserve TR 69/13.8 kV 28 MVA	NA	550,000					550,000
	E103.021680	Reserve TR 69/4.16 kV 7 MVA	NA	250,000					250,000
	E114.018129	MN - Pole Replacement Blanket	NA	37,064,000	38,190,000	38,620,000	38,875,004	39,131,000	191,880,004
	E103.012612	ELR MN Sub TRs	NA	6,976,000	8,207,000	8,454,000	8,707,921	8,970,000	41,314,921
	E103.011891	ELR MN Sub Switches	NA	6,629,000	8,032,000	8,273,000	8,522,000	8,778,000	40,234,000
	E114.021018	MN Pole Top Reinforcements	NA			6,000,000	10,000,000	12,000,000	28,000,000
	E114.021025	MN Porcelain Cutouts	NA	2,000,000	4,000,000	5,000,000	5,000,000	5,000,000	21,000,000
	E103.011890	ELR MN Sub Feeder Breakers	NA	2,992,000	3,520,000	3,626,000	3,735,004	3,847,919	17,720,923
	E144.020922	SE Region Reliability Initiative	NA	3,000,000	3,090,000	3,183,000	3,279,000	3,378,000	15,930,000
	E114.021939	MN ELR Reclosers	NA			2,000,000	3,000,000	4,000,000	9,000,000
	E103.020780	ELR Mobile Substation Renewal	NA	2,000,000	2,060,000	2,122,000	2,186,000		8,368,000
	E141.001664	ELR MPLS Vault Tops	NA	900,000	1,350,000	1,800,000	1,854,000	1,910,000	7,814,000
	E103.012586	ELR MN Sub Relays	NA	1,202,000	1,457,000	1,501,000	1,547,000	1,594,000	7,301,000
Program	E114.018792	MN LED Post Top Conversion	NA	1,000,000	1,030,000	1,061,004	1,093,004	1,126,000	5,310,008
	E141.018795	ELR MPLS Network Protectors	NA	600,000	900,000	1,200,000	1,236,000	1,274,000	5,210,000
	E141.019633	ELR MPLS Network TR	NA	600,000	900,000	1,200,000	1,236,000	1,274,000	5,210,000
	E114.021020	MN High Customer Count Taps	NA			1,000,000	2,000,000	2,000,000	5,000,000
	E114.021024	MN Pole Fire Mitigation	NA			1,000,000	2,000,000	2,000,000	5,000,000
	E103.012603	ELR MN Sub Regulators	NA	768,000	931,000	959,000	988,000	1,019,000	4,665,000
	E114.021017	MN Low Cost Reclosers (Single Phase)	NA			500,000	1,000,000	2,000,000	3,500,000
	E151.013639	ELR STP Vault Tops	NA	400,000	600,000	800,000	824,000	849,004	3,473,004
	E151.019634	ELR STP Network TR	NA	125,004	187,500	750,000	773,004	797,004	2,632,512
	E114.020921	MN Arrestor Replacement Program	NA	800,000	800,000	900,000			2,500,000
	E103.012606	ELR MN Sub Fences	NA	339,000	410,000	423,000	436,000	450,000	2,058,000
	E103.017653	ELR MN Sub Batteries	NA	313,000	380,000	392,000	404,000	417,000	1,906,000
	E151.018796	ELR STP Network Protectors	NA	125,004	187,500	250,000	258,000	266,000	1,086,504
	E114.021963	MN Multi-Feeder Pole Mitigation	NA				500,000	500,000	1,000,000
	E103.013521	ELR MN Sub RTUs	NA	153,391	185,638	191,739	197,839	203,940	932,547
WCF	E114.018276	MN - Line Asset Health WCF Blanket	NA	18,457,000	21,797,000	21,352,000	28,337,000	29,978,000	119,921,000

	Mitigation	Mitigation Name	Risk Score	2021	2022	2023	2024	2025	Grand Total
System Expansion or Upgrades for Capacity				**38,922,994**	**40,812,082**	**50,903,000**	**55,512,002**	**54,991,004**	**241,141,082**
Routines	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	NA	1,790,000	1,835,004	1,880,000	1,929,000	1,981,000	9,415,004
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	NA	1,230,000	1,260,000	1,292,000	1,326,000	1,340,000	6,448,000
	E114.018342	MN - New Business Network Blanket	NA	368,994	378,000	387,000	397,000	408,000	1,938,994
Discrete	E156.011874	Install Birch Area Sub	1.23		710,078	6,900,000			7,610,078
	E143.019908	Reinforce Hyland Lake HYL TRs	0.09	5,400,000	1,600,000				7,000,000
	E151.012409	Install Western WES TR3 & Feeders	0.20					5,300,000	5,300,000
	E156.007927	Install Goose Lake GLK TR3	0.20				1,130,000	4,130,000	5,260,000
	E156.010177	Install Kohlman Lake KOL Feeder	0.16					4,520,000	4,520,000
	E150.021635	Reinforce Pine Bend PBE TR01	0.36	100,000	4,400,000				4,500,000
	E141.009145	Install Midtown MDT TR2	0.02	4,400,000					4,400,000
	E150.021672	Install Chemolite CHE TR03	0.06					4,200,000	4,200,000
	E150.021670	Install Cottage Grove CGR TR03	0.80			100,000	4,100,000		4,200,000
	E156.015749	Install Baytown BYT Feeders	0.35		2,100,000	2,100,000			4,200,000
	E142.011721	Install Orono ORO TR2 & Feeder	0.22			250,000	3,850,000		4,100,000
	E143.017702	Install Viking VKG Feeder	0.71			50,000	4,050,000		4,100,000
	E144.013520	Install East Winona EWI TR2	0.67			100,000	3,100,000		3,200,000
	E144.013436	Reinforce Kasson KAN TR1	2.41	3,064,000					3,064,000
	E144.000793	Install Zumbrota ZUM TR	0.10				100,000	2,950,000	3,050,000
	E152.020734	Reinforce Tracy Switching Station TSS TR01	2.07		1,800,000	1,200,000			3,000,000
	E150.010914	Install Stockyards STY TR3	4.65		2,925,000				2,925,000
	E144.018971	Reinforce Veseli VES TR1	0.93		200,000	2,550,000			2,750,000
	E141.019929	Install Midtown MDT Feeder	4.40	2,716,000					2,716,000
	E144.010920	Reinforce Burnside BUR TR2	0.44			100,000	2,600,000		2,700,000
	E156.011061	Install Wyoming WYO Feeder	0.99		50,000	2,556,000			2,606,000
	E144.000791	Install La Crescent LAC TR2	4.14	100,000	2,110,000				2,210,000
	E147.011657	Install Elm Creek ECK TR4	Nondiscretionary	2,150,000					2,150,000
	E144.020614	Reinforce Faribault FAB TR1	0.12		100,000	1,925,000			2,025,000
	E147.016682	Reinforce Twin Lakes TWL081	1.75		2,000,000				2,000,000
	E144.008708	Install Cannon Falls Trans CTF TR2	1.04		200,000	1,795,000			1,995,000
	E144.010889	Reinforce Pine Island TR1	0.87		100,000	1,800,000			1,900,000
	E144.013446	Reinforce Waseca WAS TR2	0.90			100,000	1,800,000		1,900,000
	E147.013379	Extend Elm Creek ECK322 to WCR	0.29					1,810,000	1,810,000
	E152.020733	Install Southridge SRD212 Fdr	2.03	50,000	1,320,000				1,370,000
	E147.012463	Extend Crooked Lake CRL033	0.90			1,250,000			1,250,000
	E147.021614	Reinforce Osseo OSS065	1.69				1,130,000		1,130,000
	E141.019956	Reinforce Terminal TER073	0.27				1,100,000		1,100,000
	E144.002712	Install Goodview GVW Feeder	0.62			50,000	1,050,000		1,100,000
	E141.019928	Extend Saint Louis Park SLP092	0.95			1,056,000			1,056,000
	E150.020608	Install Red Rock RRK073	0.11					928,000	928,000
	E156.011752	Install Lindstrom LIN Feeder	0.27				862,000		862,000
	E154.021667	Install Feeder Tie SDX312-FSL311	9.32	750,000					750,000
	E154.018960	Reinforce Glenwood GLD Sub Equip	3.97	50,000	650,000				700,000
	E141.021662	Extend Main Street Feeder MST066	1.13			700,000			700,000
	E147.021629	Reinforce Parkers Lake PKL Sub	4.69	700,000					700,000
	E151.020596	Reinforce Shepard SHP062 and SHP071	2.24		640,000				640,000
	E141.017739	Extend Main Street MST074	7.16	600,000					600,000
	E150.020609	Extend Woodbury WDY321 for WDY312	8.33	584,000					584,000
	E141.019958	Reinforce Moore Lake MOL071	0.55				550,000		550,000
	E141.019924	Install Hiawatha West HWW Feeder	6.49	540,000					540,000
	E143.019054	Reinforce Edina EDA062	0.13					500,000	500,000
	E141.019954	Reinforce Saint Louis Park SLP087	0.28				475,002		475,002
	E152.020732	Install Lake Yankton LAY061 Neutral	5.49	360,000					360,000
	E141.020663	Install Feeder Tie ALD081-ALD098	1.04			356,000			356,000
	E141.021663	Extend Southtown Feeder SOU069	0.70				350,000		350,000
	E156.015811	Reinforce Oakdale OAD073 & OAD075	0.11					275,004	275,004
	E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	0.41		260,000				260,000

	Mitigation	Mitigation Name	Risk Score	2021	2022	2023	2024	2025	Grand Total
	E147.019056	Reinforce Basset Creek BCR062	0.67				250,000		250,000
	E147.014465	Reinforce Brooklyn Park BRP062	2.98		200,000				200,000
	E147.021080	C Reinforce Parkers Lake PKL071	Nondiscretionary	200,000					200,000
	E156.011764	Reinforce Tanners Lake TLK Sub Equip	0.80			200,000			200,000
	E147.021595	Reinforce Osseo OSS064	2.07		180,000				180,000
	E141.019955	Extend Terminal TER064	0.52				161,000		161,000
	E143.016727	Install Feeder Tie EBL064	2.97		150,000				150,000
	E141.019930	Install Feeder Tie SOU083 to MDT074	26.07	100,000					100,000
	E144.016592	Reinforce Sibley Park SIP Sub Equip	0.10			100,000			100,000
	E154.021656	Transfer BLH062 to RSP061	62.69	75,000					75,000
	E141.021647	Extend Southtown Feeder SOU087	26.03	65,000					65,000
	E154.020557	Reinforce Belgrade feeder BEG001	5.81	50,000					50,000
	E147.021613	Load Transfer OSS061-OSS075	49.45	30,000					30,000
	E114.020920	MN Grid Reinforcements	NA	2,000,000	4,000,000	8,000,000	10,000,000	12,000,000	36,000,000
Program	E103.018426	SUB MN Feeder Load Monitoring	19.20	6,450,000	6,644,000	6,844,000	7,050,000	7,262,000	34,250,000
	E114.018281	MN - Line Capacity WCF Blanket	NA	2,500,000	2,500,000	4,500,000	4,500,000	4,500,000	18,500,000
WCF	E103.006881	MN Dist Subs Capacity WCF Blanket	NA	2,500,000	2,500,000	2,762,000	3,652,000	2,887,000	14,301,000
System Expansion or Upgrades for Reliability and Power Quality				**46,700,000**	**37,801,000**	**38,938,000**	**40,108,000**	**41,313,000**	**204,860,000**
Program	E114.018278	MN - Feeder Cable Replacement	NA	6,000,000	6,180,000	6,366,000	6,557,000	6,754,000	31,857,000
	E114.018179	MN - REMS Blanket	NA	500,000	515,000	531,000	547,000	564,000	2,657,000
	E114.018180	MN - FPIP Blanket	NA	2,000,000	2,060,000	2,122,000	2,186,000	2,252,000	10,620,000
	E114.021907	MN Install Viper Reclosers CSG	NA	10,000,000					10,000,000
	E114.018277	MN - URD Cable Replacement Blanket	NA	28,000,000	28,840,000	29,706,000	30,598,000	31,516,000	148,660,000
	E114.020925	MN Cable Isolation Activities	NA	200,000	206,000	213,000	220,000	227,000	1,066,000
New Customer Projects and New Revenue				**37,816,960**	**38,750,000**	**39,700,000**	**40,676,000**	**41,733,000**	**198,675,960**
Routines	E114.018268	MN - UG Extension Blanket	NA	19,577,960	20,171,000	20,724,000	21,291,000	21,904,000	103,667,960
	E114.018269	MN - UG New Services Blanket	NA	10,706,000	11,030,000	11,332,000	11,642,000	11,978,000	56,688,000
	E114.018171	MN - OH Extension Blanket	NA	1,750,000	1,803,000	1,852,000	1,903,000	1,958,000	9,266,000
	E114.018172	MN - OH New Services Blanket	NA	1,109,000	1,143,000	1,174,000	1,206,000	1,241,000	5,873,000
	E114.018045	MN - OH New Street Light Blanket	NA	328,000	336,000	344,000	353,000	363,000	1,724,000
	E114.018046	MN - UG New Street Light Blanket	NA	261,000	267,000	274,000	281,000	289,000	1,372,000
Discrete	E144.021228	Extend Waseca WAS231	NA	85,000					85,000
WCF	E114.018270	MN - New Business WCF Blanket	NA	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	20,000,000
Projects related to Local (or other) Government-Requirements				**32,368,000**	**32,212,004**	**36,617,000**	**39,055,000**	**41,518,000**	**181,770,004**
Routines	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	NA	7,625,000	7,813,000	8,006,000	8,215,000	8,437,000	40,096,000
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	NA	5,970,000	6,117,004	6,268,000	6,432,000	6,606,000	31,393,004
	E114.018273	MN - UG Service Conversion Blanket	NA	1,523,000	1,561,000	1,600,000	1,642,000	1,686,000	8,012,000
Discrete	E151.021577	Relocate Daytons Bluff DBL061	NA	2,750,000					2,750,000
	E150.021491	Relocate Lone Oak LOK062 Feeder	NA	800,000					800,000
Program	E114.018479	MN - Pole Transfer 3rd Party Blanket	NA	700,000	721,000	743,000	766,000	789,000	3,719,000
WCF	E114.018175	MN - Mandate WCF Blanket	NA	5,000,000	8,000,000	12,000,000	14,000,000	16,000,000	55,000,000
	E141.017929	MPLS Mandates WCF	NA	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	40,000,000
Grid Modernization and Pilot Projects				**186,891,693**	**201,401,551**	**175,684,623**	**80,679,950**	**96,023,309**	**740,681,125**
AGIS	AGIS	AGIS	NA	83,573,563	119,054,012	105,803,767	13,173,877	19,915,113	341,520,333
	E103.016907	FLISR - Grid Mod - NSPM	NA	2,690,172	7,020,696	7,020,696	7,348,764	9,317,196	33,397,524
	E103.016912	FAN - Grid Mod - NSPM	NA	6,507,958	12,226,842	3,787,159	662,309		23,184,268
EV	E114.020058	MN Electric Vehicle Program	NA	84,536,000	47,742,000	41,299,000	38,209,000	42,325,000	254,111,000
	E114.021358	MN EV Public - Infrastructure	NA	4,002,000	7,886,000	9,063,000	10,940,000	12,316,000	44,207,000
	E114.021354	MN EV Fleet - Infrastructure	NA	2,511,000	2,762,000	3,038,000	3,797,000	4,747,000	16,855,000
	E114.021357	MN EV Public - Line Extension	NA	1,151,000	2,267,000	2,606,000	3,145,000	3,541,000	12,710,000
	E114.021483	MN EV Residential - Charging Equip	NA	805,000	1,217,000	1,717,000	1,717,000	1,753,000	7,209,000
	E114.021353	MN EV Fleet - Line Extension	NA	869,000	956,000	1,052,000	1,315,000	1,644,000	5,836,000
	E114.021355	MN EV Fleet - Charging Equipment	NA	246,000	270,000	298,000	372,000	465,000	1,651,000
Metering				**4,745,000**	**4,072,000**	**2,814,000**	**1,856,000**	**1,912,000**	**15,399,000**
Purch Meter	E103.001040	MN-Electric Meter Blanket	NA	4,745,000	4,072,000	2,814,000	1,856,000	1,912,000	15,399,000

	Mitigation	Mitigation Name	Risk Score	2021	2022	2023	2024	2025	Grand Total
Other				**49,232,018**	**52,753,324**	**51,496,769**	**41,537,301**	**43,316,634**	**238,336,047**
Transformer Purchases	E103.001041	MN-New Bus Transformer	NA	19,800,000	20,856,000	21,120,000	21,472,000	22,117,000	105,365,000
Fleet	NA	Fleet	NA	14,730,217	16,471,026	16,220,044	12,169,512	13,120,564	72,711,362
Program	E103.020883	NSPM Cybersecurity Measures	NA	1,859,865	2,186,692	1,272,448			5,319,004
	E114.022015	SUB MN Security Monitoring & Logging	NA	1,607,994	986,583	986,583	653,655	653,655	4,888,468
	E103.014467	Sub Fiber Communication Cutover	NA	3,957,661	4,793,467	4,793,467		653,655	14,198,249
	E103.018427	COMM MN Feeder Load Monitoring	NA	1,873,810	1,930,463	1,988,853	2,048,989	2,110,869	9,952,984
	E117.020014	ND Feeder Load Monitoring	NA	152,523	157,751	162,980	168,210	173,439	814,903
	E118.020015	SD Feeder Load Monitoring	NA	152,528	157,757	162,987	168,216	173,445	814,933
	E141.020919	Install Network Monitoring Mpls	NA	1,307,309	1,307,309	1,307,309	1,307,309	1,307,309	6,536,546
	E151.020916	Install Network Monitoring St. Paul	NA	871,539	871,539	871,539	871,539	261,462	3,747,620
Routines	E103.002265	Capitalized Locating Costs-Elec UG MN	NA	400,000	400,000	400,000	400,000	400,000	2,000,000
	C115.006786	MN-Dist Tools Common	NA	283,070	291,228	301,017	310,806	319,780	
	E103.001738	MN-Dist Subs Tools and Equip	NA	293,709	302,424	312,011	320,727	330,313	1,559,184
	E103.002100	MN-Dist Electric Tools and Equip	NA	1,763,128	1,804,894	1,408,408	1,451,113	1,494,690	7,922,232
	E145.001206	ND-Electric Tools & Equip	NA	73,209	74,952	77,567	80,182	81,925	387,835
	E153.001257	SD-Tools & Equip	NA	105,456	108,946	111,557	115,043	118,529	559,532
Discrete	E153.016550	Install Great Plains Area Sub	NA		52,292				52,292
Non-Investment				**(1,675,000)**	**(1,730,000)**	**(1,784,000)**	**(1,832,000)**	**(1,887,000)**	**(8,908,000)**
CIAC	E145.001199	Electric New Construction Contributions in Aid	NA	(1,675,000)	(1,730,000)	(1,784,000)	(1,832,000)	(1,887,000)	(8,908,000)
Grand Total				**539,349,064**	**573,326,598**	**567,716,104**	**483,098,033**	**508,542,826**	**2,672,032,626**

	2016	2017	2018	2019	2020	2021 (Fcst)	2022	2023	2024	2025	2026
New Customer Projects and New Revenue	$27.8	$32.4	$33.3	$30.4	$34.5	$38.7	$37.8	$38.8	$39.7	$40.7	$41.7
Metering	$5.1	$6.8	$5.9	$7.6	$6.9	$6.5	$4.7	$4.1	$2.8	$1.9	$1.9
System Expansion or Upgrades for Capacity	$23.3	$13.2	$13.6	$21.6	$47.4	$32.6	$38.9	$40.8	$50.9	$55.5	$55.0
Grid Modernization and Pilot Projects	$0.0	$0.0	$0.4	$7.2	$2.8	$22.6	$186.9	$201.4	$175.7	$80.7	$96.0



New Customer Projects and New Revenue (Extensions, Services, Streetlights)

- Based on estimated cost per meter and growth assumptions. Analysis does not include 2021 results (including economic considerations) and will be refreshed in 2023-2027 budget create cycle.
- Growth assumptions based on historical results, internal growth projections and known trends in service territories. Assumes current trends continue and minimal YOY growth.

Metering (Meter Purchases, does not include AGIS AMI)

- Includes 'business-as-usual' meter costs, not metering expenditures associated with our AMI plans.
- Decreasing trends driven by AMI rollout.

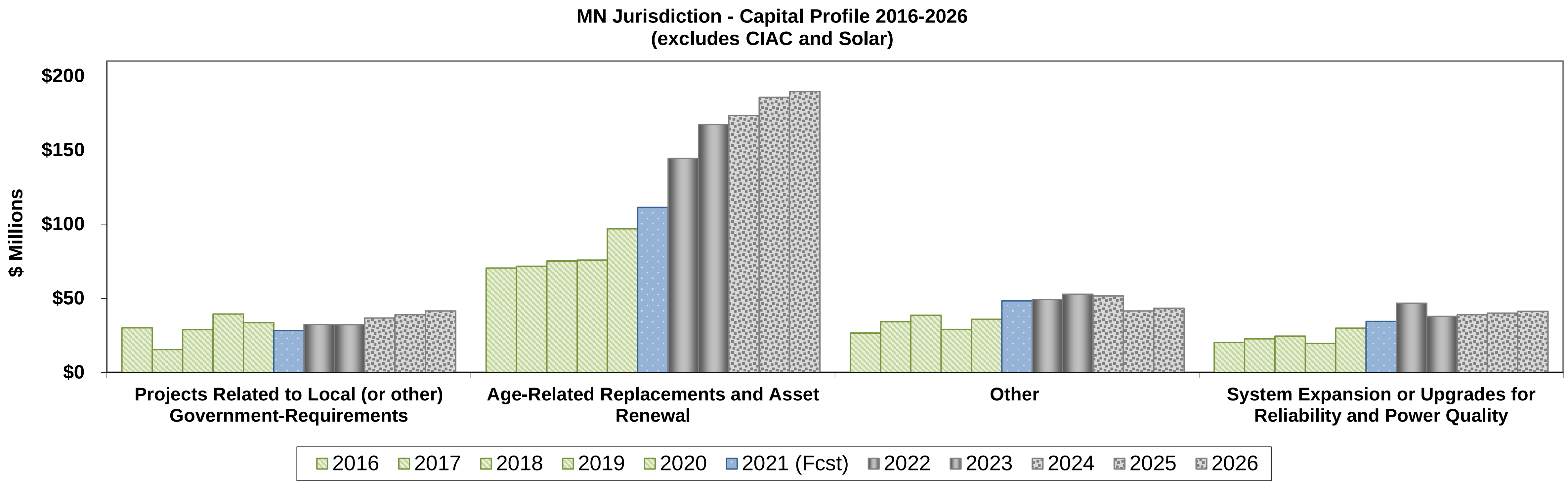
System Expansion or Upgrades for Capacity (Reinforcements)

- Continued focus on risk minimization including contingency and overload risks. Annual amounts will fluctuate based on needs in North and South Dakota, as well as timing of large projects.
- Includes the Grid Reinforcement program which is driving the uptick in years 3-5.

Grid Modernization and Pilot Projects (AGIS, EV)

- Includes Advanced Grid Infrastructure and Security (AGIS) and Electric Vehicle (EV) programs.

	2016	2017	2018	2019	2020	2021 (Fcst)	2022	2023	2024	2025	2026
Projects Related to Local (or other) Government-Requirements	$30.1	$15.4	$28.9	$39.3	$33.6	$28.3	$32.4	$32.2	$36.6	$39.1	$41.5
Age-Related Replacements and Asset Renewal	$70.4	$71.7	$75.2	$75.7	$96.9	$111.3	$144.3	$167.3	$173.3	$185.5	$189.6
Other	$26.6	$34.1	$38.5	$29.0	$35.8	$48.3	$49.2	$52.8	$51.5	$41.5	$43.3
System Expansion or Upgrades for Reliability and Power Quality	$20.2	$22.6	$24.5	$19.6	$29.8	$34.4	$46.7	$37.8	$38.9	$40.1	$41.3



Projects Related to Local (or other) Government-Requirements (Mandates)

- Increasing trends driven by large relocation projects in Minneapolis including 8th Street, Hennepin Ave and 4th Street. Southwest Light Rail Transit (SWLRT) Relocation also contributing. Surrounding communities also seeing increased relocation trends.
- Outyear budgets assume strong trends continue with large projects scheduled through 2021. Does not include 2021 economic considerations. Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.

Age-Related Replacements and Asset Renewal (Rebuilds, Conversions)

- Comprehensive suite of programs and projects aimed at replacing aging infrastructure. Includes funds for failure restoration.
- Increasing aging infrastructure population driving increased budgets including pole replacements, substation equipment, network equipment and various discrete projects to address aging infrastructure or reliability (substation rebuilds, 4kV conversions, etc.).
- Increased funding also includes placeholders for a number of new programs designed to target aging infrastructure, increase reliability and increase system resiliency.

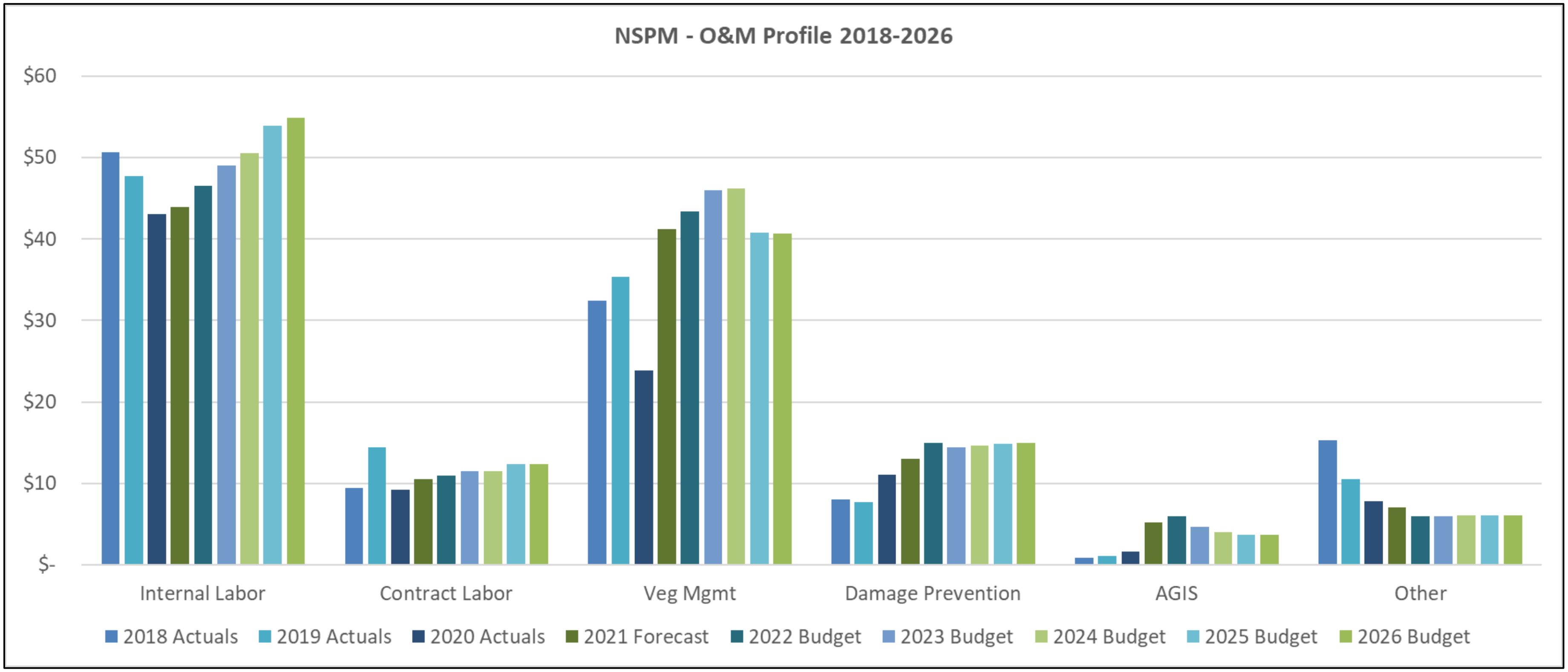
Other (Fleet, Tools, Communication Equipment, Transformer Purchases, Advanced Planning Tool)

- Increasing trends driven by increasing fleet needs and new programs.
- Includes placeholders for new programs for installing communication in our downtown networks (Network Monitoring), privatizing our substation communication network (Fiber Buildout) and increasing cyber security (Cyber Security).

System Expansion or Upgrades for Reliability and Power Quality (Cable Replacement and Reliability Programs)

- Outyear budgets assumes current failure trends continue and ensures current level of reliability is maintained.
- Uptick in 2022 driven by CSG Viper Recloser program (installing Viper Reclosers on all existing Community Solar Gardens).

Figure 1: Distribution O&M Profile Trend (2018 to 2026)
NSPM – Total Company Electric



Other: Includes materials, employee expenses, transportation costs, first set credits, bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Xcel Energy
Partners in Energy - Minnesota Community Participation
As of August 2021

Community	Goal(s) for Generation Sources	EVs or electrification of transportation	Local Solar or Distributed Generation Goal	Electrification of building stock	Notes
Bloomington	Reduce city-wide energy-related greenhouse gas emissions by 75% by 2035, relative to 2016 levels	Strategies for fleet electrification and charging at City	Strategies for on-site solar and renewable energy	Strategies for electrification	
Eden Prairie	Reduce energy-related greenhouse gas emissions 30% by 2025, 80% by 2050	Strategies for fleet electrification and charging at City	Strategies for on-site solar and renewable energy	Strategies for electrification in CAP	Climate Action Plan adopted in 2020 with more aggressive goals
Edina	Reduce energy-related greenhouse gas emissions 30% by 2025, 80% by 2050		Strategies for on-site solar and renewable energy		Climate Action Plan in progress, will focus on electrification and fleet
Faribault	Reduce community-wide energy expenditure by 1% annually from business as usual (2015 baseline)				
Fridley	Reduce community energy use by 5% by 2020, 30% by 2030	Strategies to promote Evs and charging			
Golden Valley	Eliminate 65,000 tons of greenhouse gas emissions through electricity and natural gas savings in the next 10 years, for a reduction of approximately 30%.	Strategies to promote Evs and charging	Strategies for on-site solar and renewable energy		
Hastings					Energy Action Plan focusing on DSM participation
Inver Grove Heights		Strategies to promote Evs and charging	Strategies for on-site solar and renewable energy		Energy Action Plan focusing on DSM participation
La Crescent		Strategies to promote Evs and charging	Strategies for on-site solar and renewable energy	Strategies for electrification	Energy Action Plan focusing on DSM participation
Mahtomedi	Achieve a 100% reduction in greenhouse gas emissions by 2050				
Maplewood		Strategies for fleet electrification and charging at City	Strategies for on-site solar and renewable energy		New Climate Action Plan/Sustainability Plan with more aggressive goals
Minnetonka	Reduce energy-related greenhouse gas emissions by 160,000 MTCO2e before the end of 2030				
Northfield	Achieve 100% carbon-neutrality by 2040	Strategies for fleet electrification and charging infrastructure	Strategies for on-site solar and renewable energy	Strategies for electrification	Climate Action Plan adopted in 2018 with more aggressive goals
Red Wing					New Climate Action Plan/Sustainability Plan with more aggressive goals

Community	Goal(s) for Generation Sources	EVs or electrification of transportation	Local Solar or Distributed Generation Goal	Electrification of building stock	Notes
Richfield	Reduce community-wide greenhouse gas emissions from electricity and natural gas by 15 percent (below a 2019 baseline) by 2032 through all of the focus area goals				Energy Action Plan focusing on DSM participation
Rosemount	Reduce energy use by 20% by 2030				
Roseville		Strategies to promote Evs and charging	Engage 100 residents and 5 businesses annually to encourage them to subscribe to renewable energy		
Saint Paul	Achieve carbon neutrality by 2050	Strategies for fleet electrification and charging infrastructure	Strategies for on-site solar and renewable energy	Strategies for electrification	Climate Action and Resilience Plan with more aggressive goals and strategies
Shorewood					Energy Action Plan focusing on DSM participation
St. Cloud			Help institutions and businesses replace 21.8 million kWh of electricity with renewables by 2026		
St. Louis Park	Achieve carbon neutrality by 2040, Source 100% renewable electricity by 2025	Strategies for fleet electrification and charging infrastructure	Installation of 200 killowatts of rooftop solar and a one megawatt community solar garden	Source 100% renewable electricity by 2025	Climate Action Plan with more aggressive goals and strategies
Wayzata					Energy Action Plan focusing on DSM participation
Winona	Achieve carbon neutrality by 2050				

NON-WIRES ALTERNATIVES ANALYSIS – PROJECT DETAILS

This attachment contains additional details regarding our non-wires alternatives (NWA) analysis for the 2021 IDP. Part I provides an overview of our screening results and candidate projects. Part II provides the assumptions for each project analyzed. Part III discusses the results of the analysis. Part IV provides the load curves for each project.

I. OVERVIEW

As discussed in *Appendix F: Non-Wires Alternatives Analysis* of the IDP, we performed an NWA analysis on a set of projects that met our screening criteria. See Table 1 below for the list of 2021 projects analyzed that met the criteria.

Initial Projects Evaluated

Table 1:

Project	2022	2023	2024	2025	2026	22-26 Total
Install Kohlman Lake KOL Feeder	$0	$0	$0	$0	$4,520,000	$4,520,000
Install Viking VKG Feeder	$0	$0	$50,000	$4,050,000	$0	$4,100,000
Install Wyoming WYO Feeder	$0	$50,000	$2,556,000	$0	$0	$2,606,000
Reinforce Veseli VES TR1	$0	$200,000	$2,550,000	$0	$0	$2,750,000
Install Zumbrota ZUM TR	$0	$0	$0	$100,000	$2,950,000	$3,050,000
Install Chemolite CHE TR03	$0	$0	$0	$0	$4,200,000	$4,200,000
Install Goose Lake GLK TR3	$0	$0	$0	$1,130,000	$4,130,000	$5,260,000
Install Orono ORO TR2 & Feeder	$0	$0	$250,000	$3,850,000	$0	$4,100,000
Reinforce Burnside BUR TR2	$0	$0	$100,000	$2,600,000	$0	$2,700,000
Install Cottage Grove CGR TR03	$0	$0	$100,000	$4,100,000	$0	$4,200,000
Install Cannon Falls Trans CTF TR2	$0	$200,000	$1,795,000	$0	$0	$1,995,000
Install Western WES TR3 & Feeders	$0	$0	$0	$0	$5,300,000	$5,300,000
Reinforce Faribault FAB TR1	$0	$100,000	$1,925,000	$0	$0	$2,025,000
Install East Winona EWI TR2	$0	$0	$100,000	$3,100,000	$0	$3,200,000

For each of these projects, we focused on the forecasted 2034 peak load curve for each feeder or transformer risk involved. We then applied focused demand response (DR) in an effort to reduce the load – and followed that with energy storage and/or solar generation to address the remainder of the deficiency. In some instances, we had existing solar on particular feeders that we could utilize in the analysis as well.

We only considered DR for the N-0 risks. This is partially due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data such as individual customer loads. By focusing on the N-0 risks at this time, we are looking to develop a process, observe the value, and determine next steps for all risks.

Table 2 below summarizes the outcome of our NWA analysis for the projects that advanced to a full NWA analysis.

2021 NWA Candidate Projects – Results Summary

Table 2

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA	Cost of Traditional Project
Install Kohlman Lake KOL Feeder	7	11.25	50.39	$17.0	$4.52
Install Viking VKG Feeder	3	10.3	62.6	$17.9	$4.1
Install Wyoming WYO Feeder	5	14.38	97.14	$28.5	$2.5
Reinforce Veseli VES TR1 & Feeder	3	10.99	69.75	$41.8	$2.8
Install Zumbrota ZUM TR	2	10.97	73.34	$41.8	$3.0
Install Chemolite CHE TR03	5	28.82	151.18	$11.8	$4.0
Install Goose Lake GLK TR3 & Feeders	8	29.53	179.03	$37.9	$6.4
Install Orono ORO TR2 & Feeder	3	15.40	279.70	$68.9	$4.1
Reinforce Burnside BUR TR2	3	17.8	135.06	$69.6	$2.7
Install Cottage Grove CGR TR03	4	64.27	321.39	$46.6	$4.2
Install Cannon Falls Trans CTF TR02 & Fdr	4	17.43	141.13	$108.0	$2.0
Install Western WES TR3 & Feeders	9	34.97	185.33	$95.4	$5.3
Reinforce Faribault FAB TR1	5	32.3	234.31	$125.8	$2.0
Install East Winona EWI TR2	6	21.79	166.46	$115.6	$3.2

As we also noted in Appendix F, comparing an NWA to a traditional project is not always a clear one-to-one comparison, because in some instances, the NWA is not able to fully solve all of the risks that the traditional project solved. As also discussed in Appendix F, we explored a new approach to NWA analysis with stakeholders in 2021, including use of a broader set of values and revenue streams for future NWA analyses. We are proposing to use that new approach for our 2022 NWA analyses. That said, the below sections provide the details of our 2021 NWA analysis using our current methodology.

II. ASSUMPTIONS

For all NWA studies, we made reasonable assumptions toward streamlining the process. Our goal in these studies is to reduce overloads and contingencies down to 100 percent of the capacity rating, meaning that there is no "spare" capacity in these solutions. Therefore, any additional load growth in future years that could cause additional risk would require an additional risk analysis, associated mitigation, and potentially another NWA analysis.

When conducting an NWA analysis, we assumed that peak day conditions contain the highest magnitude of risk. Therefore, rather than doing the analysis for potentially multiple overload events during the year, NWA studies are done utilizing available SCADA data containing peak day conditions. When SCADA data is not available, we use LoadSEER to generate peak day load curves. We selected historical 2019 peak days and scaled them to 2034 forecast peak values to accommodate the 3-year minimum that it would take to install an NWA solution in the field. While 2020 historical SCADA data is available, we used 2019 peak days because the 2020 load curves contain pandemic-related loading impacts that do not represent typical load patterns. We selected the 2034 forecast year to consider an additional 10 years beyond the 3-year minimum for in-servicing the NWA solution. These 10 additional years also align with NWA analysis practices that are commonly seen across the utility industry, which accounts for the lifespan of a typical NWA solution.

When approaching feeder and transformer risks, load that was not able to be offset by solar or DR resulted in energy storage solutions. Unless extreme circumstances dictated otherwise, it was assumed that these energy storage systems would be available during risk hours to mitigate contingencies and overloads.

The minimum solar output curves we used ranged from 24-36 percent of peak output from 10:00 AM to 4:00 PM, and to percentages less than that outside of that timeframe. We obtained these solar curves from the NREL PV Watts tool.

The DR curves we applied assumed peak at 6:00 PM on associated feeders. Load reduction curves from DR were applied to risks that had N-0 overloads. Risks containing N-1 contingencies were generally not considered for DR due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data, such as individual customer loads.

Energy efficiency is already included in our load forecasts and so are common to both the traditional projects and the NWAs and therefore not considered as an NWA component. We did not consider use of NWAs for voltage optimization in this analysis, nor were other potential value streams. As noted previously, we explored use of a broader set of values and revenue streams for future NWA analyses with stakeholders in 2021, which we discuss in Appendix F.

Regarding cost assumptions, previously we utilized a flat battery storage unit cost based solely on energy capacity (MWh) using existing available industry costs. In the 2021 NWA analysis, we used new battery storage costs to reflect both the energy (MWh) and power (MW) components of battery storage systems. We obtained the formula we used to calculate these costs from the NREL Annual Technology Baseline (ATB), which is shown in Table 3 below.

Cost Assumptions in NWA Analysis

Table 3:

Assumption	Cost
Battery Storage Energy Costs	$223,000/MWh
Battery Storage Power Costs	$405,000/MW
Battery Storage Power Constant	$250,929
Total Battery Cost	Total System Cost ($) = Battery Storage Capacity (MWh) * Battery Energy Cost ($/MWh) + Battery Power Capacity (MW) * Battery Power Cost ($/MW) + Battery Power Constant ($)
Solar PV Costs	$2,000,000/MW
O&M Costs	Not Included in Analysis
Land Costs	Not Included in Analysis
End of Life Replacement Costs	Not Included in Analysis

Although battery storage systems are not 100 percent efficient and incur losses during the charging and discharging of the system, for purposes of this analysis, we did not account for additional battery capacity from losses. We also did not include O&M costs related to maintaining solar or battery storage systems. Additionally, we assumed that land would be available at key locations on feeders/transformers/ substations that would enable the NWA solution.

III. PROJECT ANALYSIS RESULTS

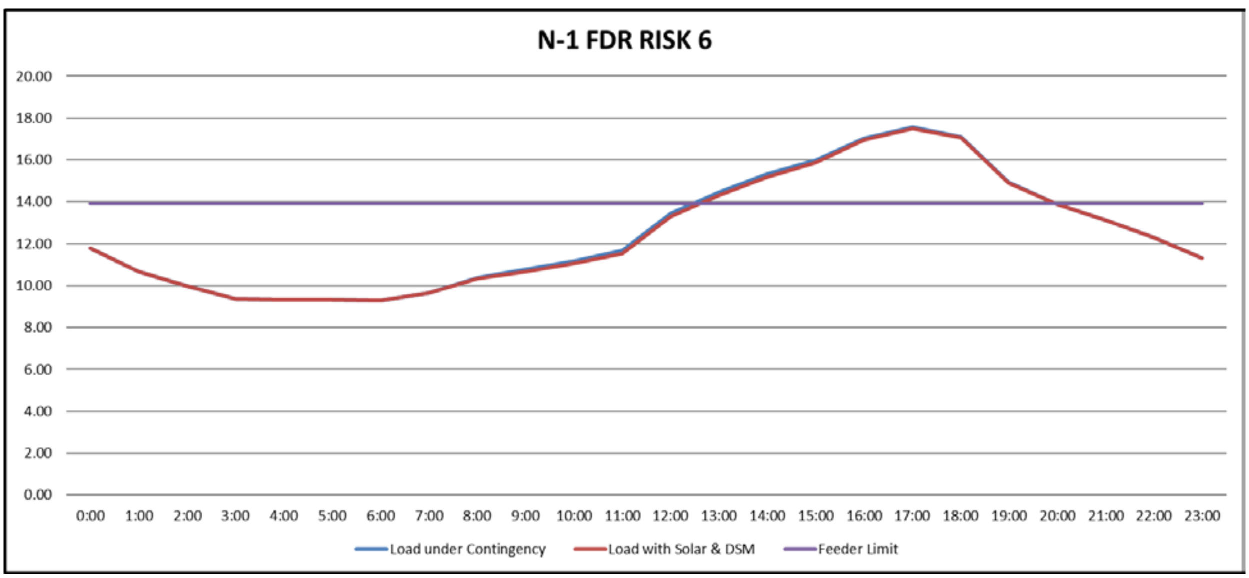
This section contains a summary of each of our NWA project analyses, including one example chart for each project to illustrate the risk assessment process. We provide additional charts of the risks for each of the projects in Part IV. We note that we consolidated feeder contingency risks with multiple contributing sections to represent a single total value, representing the total cost to address the risk.

A. Install Kohlman Lake KOL Feeder

This project addresses seven feeder risks, all of which are due to contingencies. The traditional project in the budget involves installing one new feeder and feeder bay at the Kohlman Lake substation, as well as a series of load transfers. The NWA solution for this project involves placing energy storage systems at strategic locations on the feeders to mitigate risks and keep costs at a minimum. We assumed that these energy storage systems could be strategically placed at feeder ties to mitigate the contingencies.

Figure 1 shows the amount of load at risk for loss of one of the feeders associated with the project.

Figure 1: Feeder N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could discharge 3.57 MW at peak, and 14.33 MWh of energy throughout the day.

This energy storage system would solve the feeder N-1 risk.

Table 4: Install Kohlman Lake KOL Feeder – Summary of DER Solutions

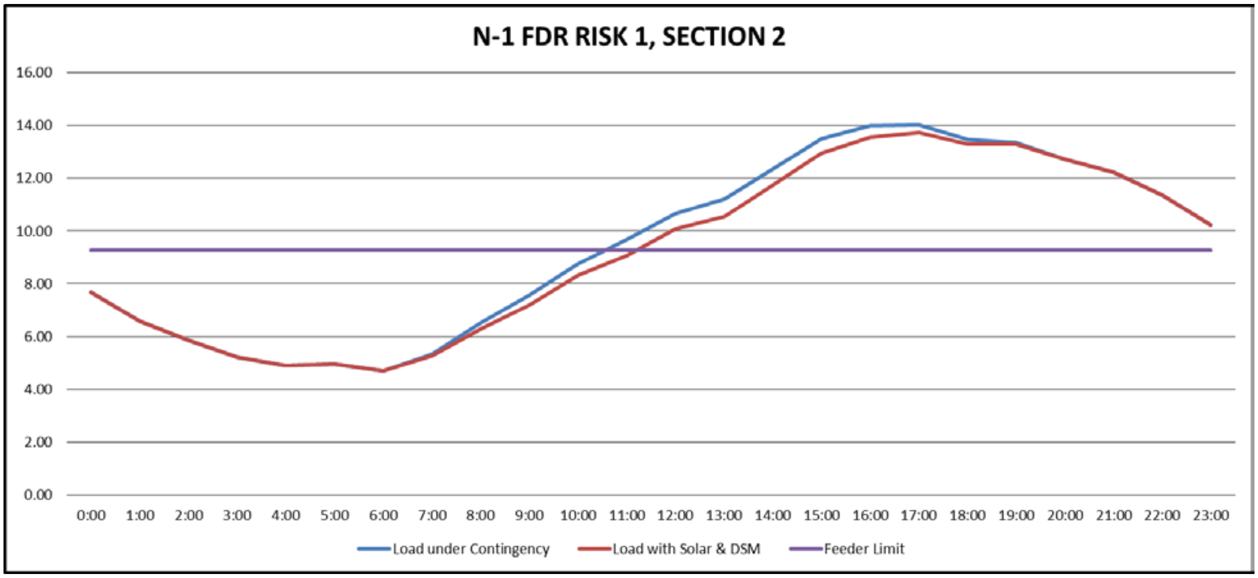
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	3.10	12.58	0.00	0.00	0.00	3.10/12.58	$4,309,976
N-1 FDR RISK 2	2.74	17.21	0.00	0.00	0.00	2.74/17.21	$5,197,632
N-1 FDR RISK 3	0.85	3.41	0.00	0.00	0.00	0.85/3.41	$1,358,498
N-1 FDR RISK 4	2.69	15.91	Mitigated with optimal energy storage				
N-1 FDR RISK 5	1.53	3.69	Mitigated with optimal energy storage				
N-1 FDR RISK 6	3.57	14.33	0.00	0.40	0.00	3.57/14.33	$4,890,447
N-1 FDR RISK 7	0.99	2.86	0.00	0.50	0.00	0.99/2.86	$1,289,910
Total			0.00	0.90	0.00	11.25/50.39	$17,046,463

B. Install Viking VKG Feeder

This project addresses three feeder risks; two of which are due to contingencies and one due to a normal overload. The traditional project in the budget involves installing one new feeder and feeder bay at the Viking substation. The NWA solution for this project involves placing energy storage systems at strategic locations on the feeders to mitigate risks and keep costs at a minimum. It was assumed that these energy storage systems could be strategically placed at feeder ties to mitigate the contingencies and normal overload.

Figure 2 shows the amount of load at risk for loss of one of the feeders associated with the project.

Figure 2: Feeder N-1 Contingency Load Risk



The feeder currently has 0.19 MW of existing solar. In the current condition, there would need to be an energy storage system installed that could discharge 4.45 MW at peak, and 34.41 MWh of energy throughout the day. An addition of 1.6MW of new solar would need to be installed in order for this battery energy storage system to be able to recharge enough energy to be able to discharge at a future cycle. The combination of new solar and a battery energy storage system would mitigate the feeder N-1 risk.

Table 5:

Install Viking VKG Feeder – Summary of DER Solutions

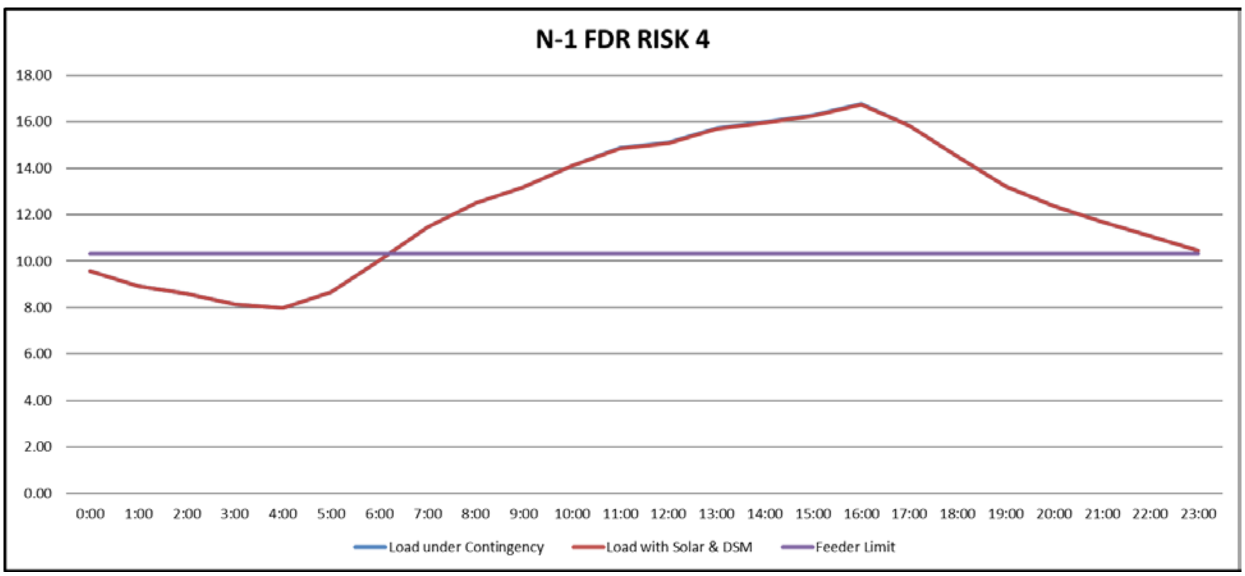
Capacity Risk	Overload Magnitude			Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	7.55	49.95	0.00	2.9	1.60	7.55/49.95	$17,896,673
N-1 FDR RISK 2	2.40	11.85	Mitigated with optimal energy storage placement				
N-0 FDR RISK 1	0.35	0.84	Mitigated with optimal energy storage placement				
Total			0.80	2.9	1.60	7.55/49.95	$17,896,673

C. Install Wyoming WYO Feeder

This project addresses four feeder risks, all of which are due to contingencies. The traditional project in the budget involves installing one new feeder and feeder bay at the Wyoming substation, as well as doing a series of load transfers. The NWA solution for this project involves placing energy storage systems at strategic locations on the feeders to mitigate risks and keep costs at a minimum. It was assumed that these energy storage systems could be strategically placed at feeder ties to mitigate the contingencies.

Figure 3 shows the amount of load at risk for loss of one of the feeders associated with the project.

Figure 3: Feeder N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could discharge 6.41 MW at peak, and 59.18 MWh of energy throughout the day. This energy storage system would solve the feeder N-1 risk.

Table 6:

Install Wyoming WYO Feeder – Summary of DER Solutions

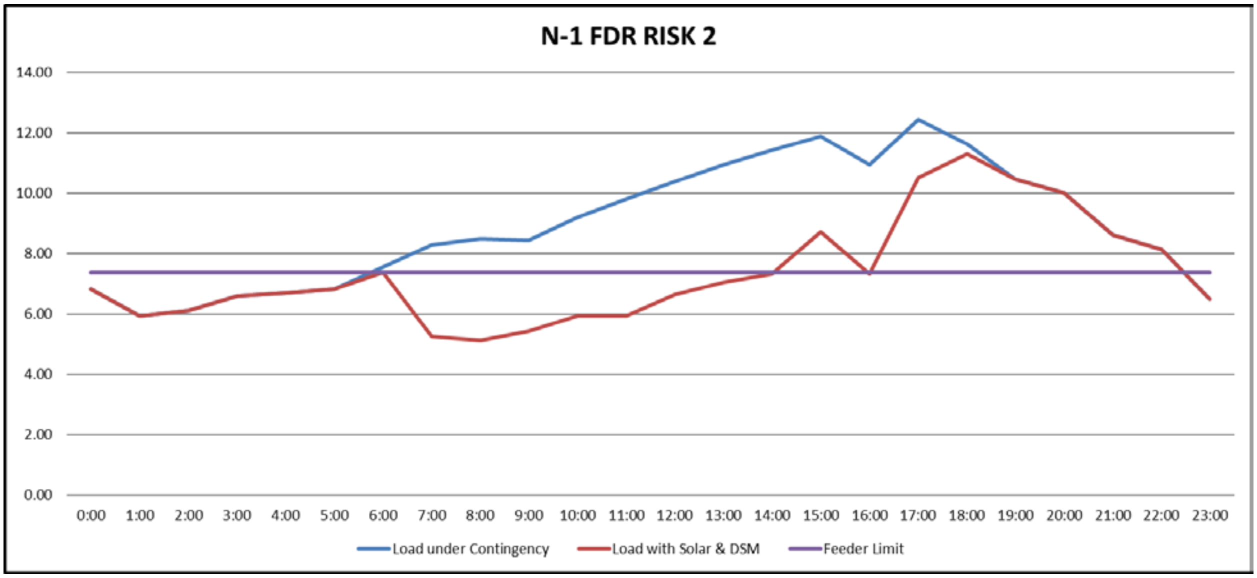
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	2.55	10.58	0.00	0.10	0.00	2.55/10.58	$3,640,978
N-1 FDR RISK 2	3.30	19.53	0.00	0.00	0.00	3.30/19.53	$5,943,223
N-1 FDR RISK 3	2.11	7.63	0.00	0.00	0.00	2.11/7.63	$2,807,015
N-1 FDR RISK 4	6.41	59.18	0.00	0.00	0.00	6.41/59.18	$16,043,944
Total			0.00	0.20	0.00	14.36/96.92	$28,435,162

D. Install Veseli VES TR1 & Feeder

This project addresses three feeder risks, one of which is a normal overload and two are due to contingency. The traditional project in the budget involves installing a new transformer and an additional feeder at the Veseli substation. The NWA solution for this project involves existing solar generation on Elko (EKO) and Veseli (VES) feeders (9MW on VES and 1MW on EKO) combined with DR potential and new energy storage. It is assumed that one energy storage device could be placed at the feeder tie to minimize the location of deployment and solve all of the feeder risks.

Figure 4 shows the amount of load at risk for loss of one of the feeders associated with the project.

Figure 4: Feeder N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could discharge 7.03 MW at peak, and 53.56 MWh of energy throughout the day. An addition of 13.4 MW of new solar would need to be installed in order for the battery energy storage system to be able to recharge enough energy to be able to discharge at a future cycle. The combination of new solar and a battery energy storage system would mitigate the feeder N-1 risk.

Table 7:

Reinforce Veseli TR1 – Summary of DER Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-0 FDR RISK 1	0.04	0.04	Mitigated with optimal energy storage placement				
N-1 FDR RISK 1	3.92	16.16	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	7.03	53.56	0	9	13.4	7.03/53.56	$41,842,346
Total			0	9	13.4	7.03/53.56	$41,842,346

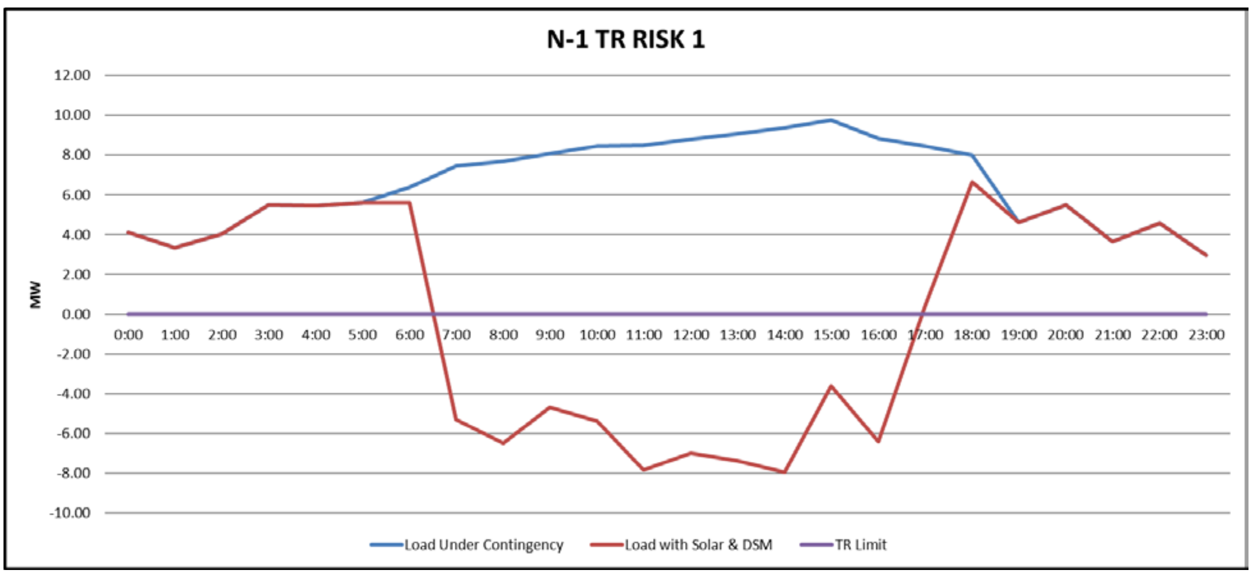
E. Install Zumbrota ZUM TR2

This project addresses one feeder risk and one transformer risk, both of which are due to contingency. The transformer is isolated in the substation, so it is analyzed as a single transformer substation. For loss of this single transformer some of the load can be transferred using feeder ties that tie to adjacent substations, but there is remaining load at risk that cannot be transferred. The traditional project in the budget involves installing a new 12.47kV transformer in the Zumbrota substation and one additional feeder.

The NWA solution for this project involves placing energy storage systems at strategic locations on the feeders and near the substation to mitigate risks and keep costs at a minimum. It was assumed that the energy storage systems could be strategically placed at feeder ties to mitigate the contingencies.

Figure 5 shows the amount of load at risk for loss of one of the substation transformers associated with the project

Figure 5: Substation Transformer N-1 Contingency Load Risk



In the current condition, there would need to be energy storage installed that could discharge 6.65MW at peak and 61.95 MWh of energy throughout the day. This energy storage installation would be large enough to address both the substation transformer N-1 risk, as well as the feeder N-1 risk.

The transformer referenced in Figure 5 is isolated and unable to transfer load to an adjacent transformer inside the substation. For this reason, the transformer limit is shown as zero. When observing the load curve (total load under contingency) it's important to understand that there would not be enough available capacity under the transformer limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, the assumption is that the battery would be charged and available for one day of use. For a multi-day event, the assumption is that the energy storage device would be used for the first 24 hours while a mobile transformer is mobilized for use after that. While this NWA does not equal the traditional solution in terms of availability for multi day events, the NWA would address the risk for 24 hours.

Table 8: Install Zumbrota ZUM TR2 – Summary of DER Solutions

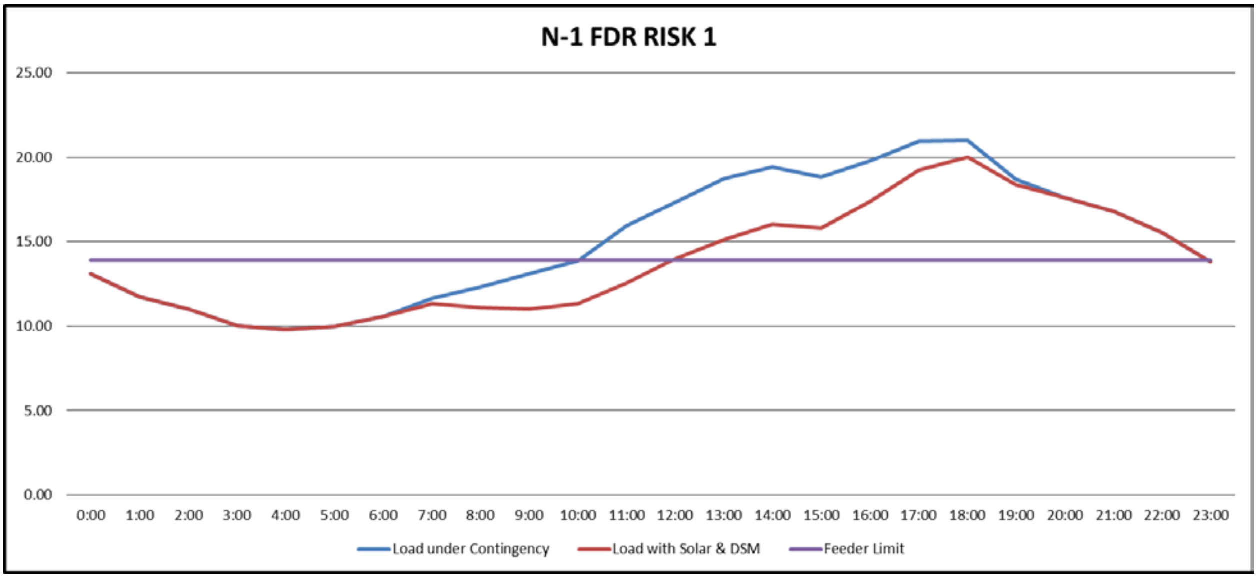
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	4.32	11.39	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	6.65	61.95	0	15	12.5	6.65/61.95	$41,758,052
Total			0	15	12.5	6.65/61.95	$41,758,052

F. Install Chemolite CHE TR03

This project addresses three feeder risks and two substation transformer risks, all of which are due to contingency. The traditional project in the budget involves the installation of a new 13.8 kV transformer and additional feeders at the Chemolite substation. The NWA solution considers the existing PV generation present at Cottage Grove as well as considers additional PV and energy storage. With optimal placement of these additional resources, five energy storage sites are needed to resolve the risks present.

Figure 6 shows an example of the amount of load at risk for loss of one of the feeders associated with the project.

Figure 6: Feeder N-1 Contingency Risk



In the current condition, there would need to be an energy storage system installed that could discharge 6.08 MW at peak, and 32.8 MWh of energy throughout the day. This energy storage system would mitigate the entirety of this section of the feeder N-1 contingency risk.

Table 9:

Install Chemolite CHE TR03 – Summary of DER Solutions

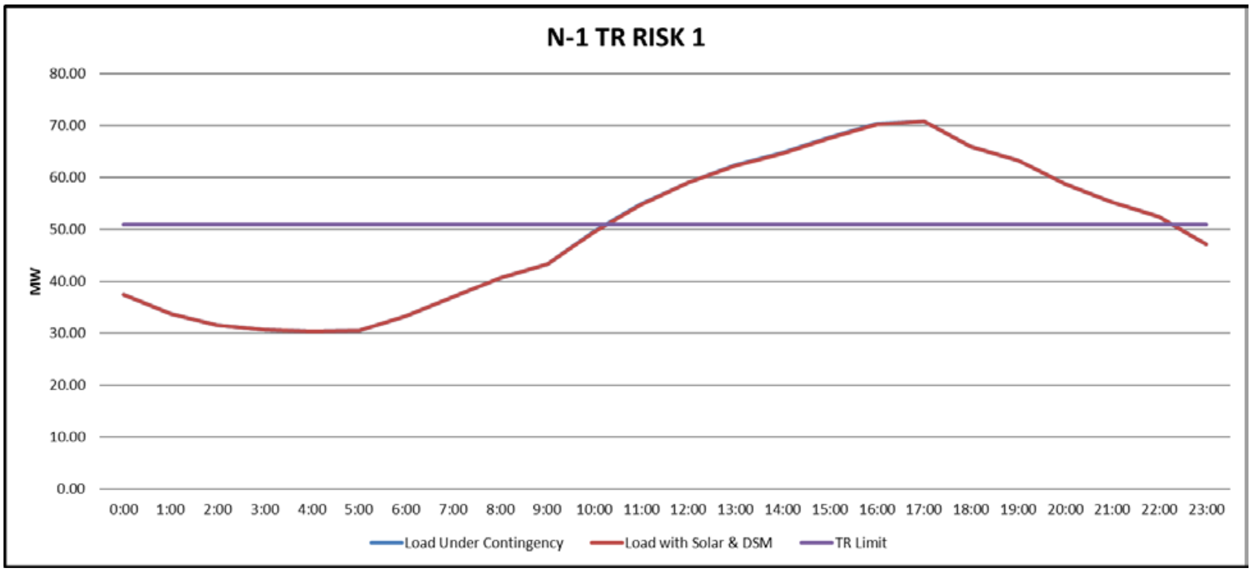
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	6.08	32.80	Mitigated with optimal DER storage placement				
N-1 FDR RISK 2	3.67	22.24	Mitigated with optimal DER storage placement				
N-1 FDR RISK 3	2.09	4.58	Mitigated with optimal DER storage placement				
N-1 TR RISK 1	7.98	37.16	0.0	0.75	0	8.0/37.2	$11,769,120
N-1 TR RISK 2	7.98	32.39	Mitigated with optimal DER storage placement				
Total			0	0.75	0	8.0/37.2	$11,769,120

G. Install Goose Lake GLK TR3 & Feeders

This project addresses six feeder risks and two substation transformer risks, all of which are due to contingencies. The traditional project in the budget involves installing one new substation transformer, two feeder bays, and two new feeders at the Goose Lake substation. The NWA solution for this project involves placing energy storage systems at strategic locations to mitigate risks and keep costs at a minimum. It was assumed that the energy storage systems could be strategically placed at feeder ties to mitigate all of the feeder risks.

Figure 7 shows the amount of load at risk for loss of one of the substation transformers associated with the project.

Figure 7: Substation Transformer N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could discharge 19.80 MW at peak, and 132.88 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both substation transformer N-1 risks.

Table 10:

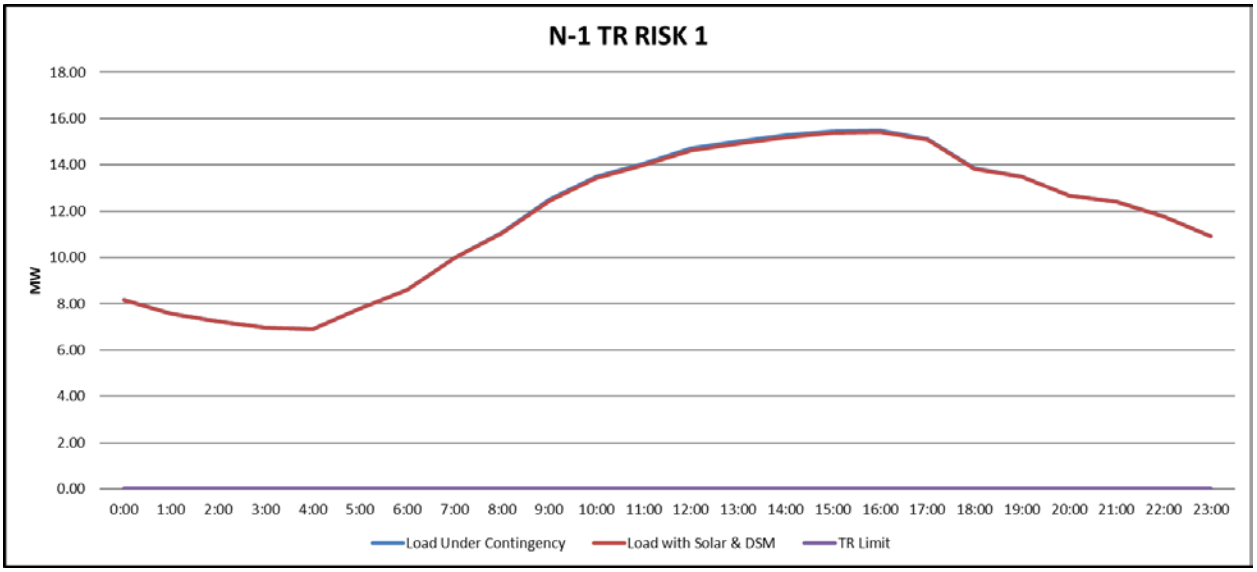
Install Goose Lake GLK TR3 & Feeders – Summary of DER Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	1.03	3.20	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	1.22	4.39	Mitigated with optimal energy storage placement				
N-1 FDR RISK 3	1.78	6.93	Mitigated with optimal energy storage placement				
N-1 FDR RISK 4	1.24	4.16	Mitigated with optimal energy storage placement				
N-1 FDR RISK 5	2.21	11.72	Mitigated with optimal energy storage placement				
N-1 FDR RISK 6	3.28	18.95	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	19.80	132.88	Mitigated with optimal energy storage placement				
N-1 TR RISK 2	19.80	132.88	0.00	0.3	0.00	19.80/132.88	$37,902,424
Total			0.00	0.3	0.00	19.80/132.88	$37,902,424

H. Install Orono ORO TR2 & Feeder

This project addresses two feeder risks and one substation transformer risk, all of which are due to contingency. The traditional project in the budget involves the installation of a new transformer and an additional feeder at the Orono substation. The NWA solution for this project involves placing energy storage systems at strategic locations to mitigate risks and keep costs at a minimum. It was assumed that the energy storage systems could be strategically placed at feeder ties to mitigate all of the feeder risks. Figure 8 shows the amount of load at risk for loss of one of the substation transformers associated with the project.

Figure 8: Substation Transformer N-1 Contingency Load Risk



In the current condition, there would need to be energy storage installed that could discharge 15.4 MW at peak and discharging 279.7 MWh of energy throughout the day. The transformer referenced in Figure 8 is isolated and unable to transfer load to an adjacent transformer inside the substation. For this reason, the transformer limit is shown as zero. When observing the load curve (total load under contingency) it is important to understand that there would not be enough available capacity under the transformer limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, the assumption is that the battery would be charged and available for one day of use. For a multi-day event, the assumption is that the energy storage device would be used for the first 24 hours while a mobile transformer is mobilized for use after that. While this NWA does not equal the traditional solution in terms of availability for multi-day events, the NWA would address the risk for 24 hours.

Table 11: Install Orono ORO TR2 & Feeder – Summary of DER Solutions

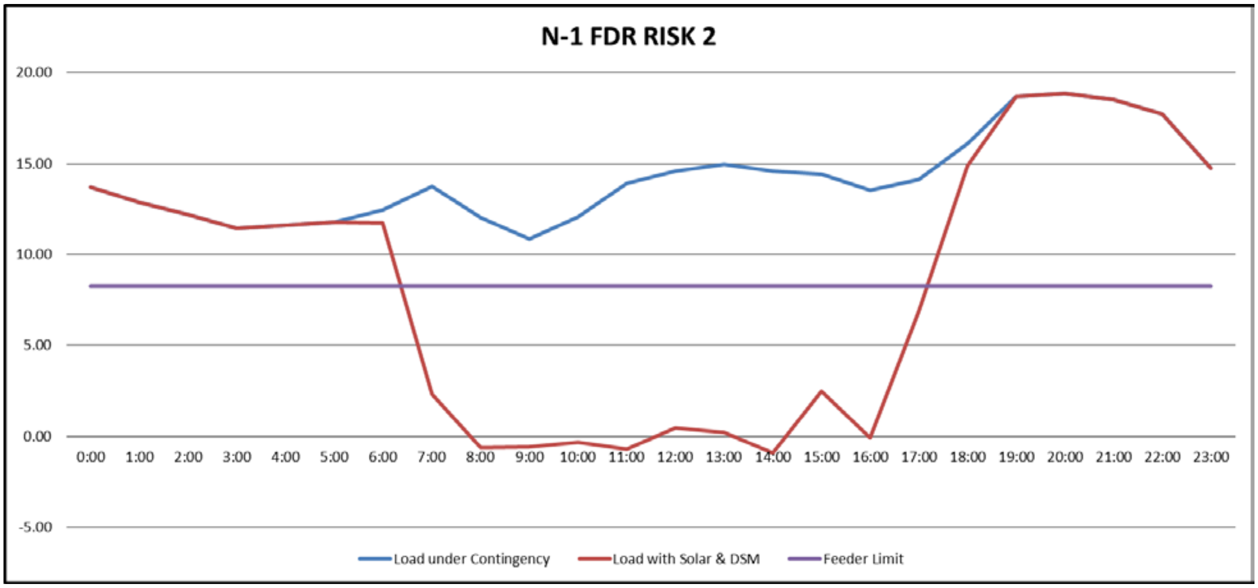
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	5.29	32.41	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	1.79	5.48	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	15.40	279.70	0	0.268	0	15.4/279.7	$68,861,162
Total			0	0.268	0	15.4/279.7	$68,861,162

I. Reinforce Burnside BUR TR2

This project addresses two feeder risks and one substation transformer risk. All three of these risks are due to contingency. The traditional project in the budget involves upgrading one substation transformer and the building of a new feeder at the Burnside substation. The NWA solution for this project involves placing energy storage systems at strategic locations in combination with existing solar generation on the Red Wing and Burnside substations. Those amounts of existing generation were combined with new energy storage. It assumed that an energy storage device could be placed at strategic locations to minimize the locations of deployment and mitigate the risks. The need for additional solar PV was identified in cases where there is not sufficient capacity available to charge the energy storage prior to when its discharge is needed.

Figure 9 shows the amount of load at risk for loss of one of the feeders associated with the project.

Figure 9: Feeder N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 10.6 MW at peak and discharging 81.6 MWh of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project. It would be large enough to mitigate two of the feeder N-1 risks.

Table 12:

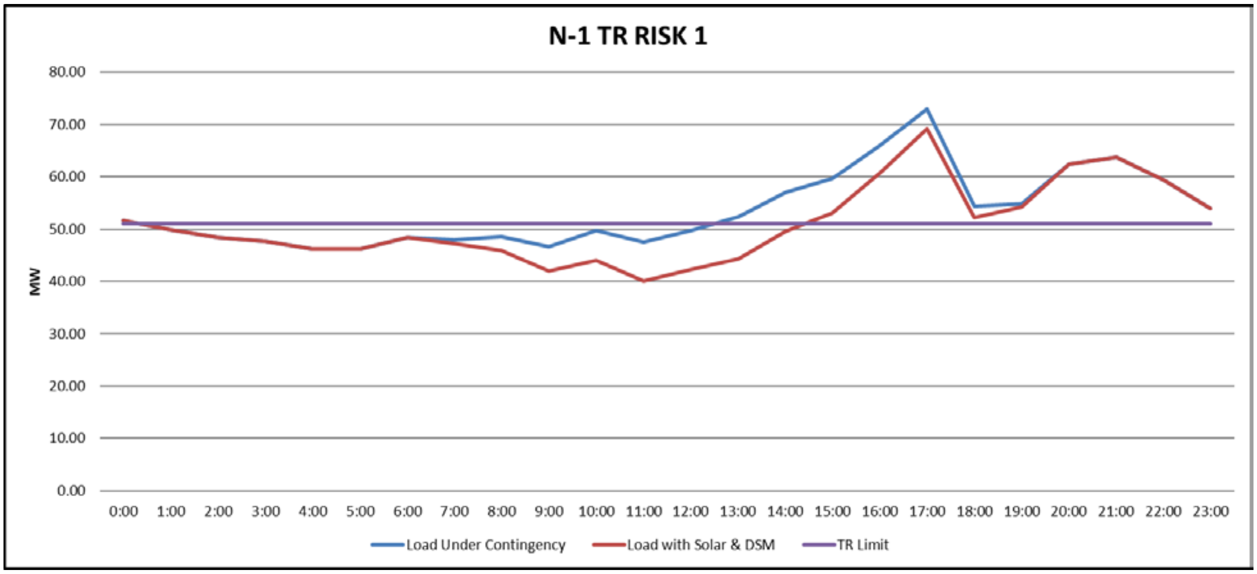
Reinforce Burnside BUR TR2 – Summary of DER Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	7.03	53.29	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	10.6	81.6	0	0	24.6	10.6/81.6	$71,941,591
N-1 TR RISK 1	0.17	0.17	0	9.4	0	0.17/0.17	$358,825
Total			0	9.4	24.6	10.77/81.77	$72,300,416

J. Install Cottage Grove CGR TR03

This project addresses seven feeder risks and two substation transformer risks; one feeder risk is a normal overload while the rest are due to contingency. The traditional project in the budget involves the installation of a new transformer in the Cottage Grove substation and additional feeders. The NWA solution involves the existing PV generation present on the Cottage Grove substation combined with additional new PV and energy storage. With optimal placement of these additional resources, seven energy storage sites are needed to resolve the risks present. Figure 10 shows the amount of load at risk for loss of one of the substation transformers associated with the project.

Figure 10: Substation Transformer N-1 Contingency Risk



In the current condition, there would need to be an energy storage system installed that could discharge 18.2 MW at peak, and 103.1 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate the entire substation transformer N-1 contingency risk.

Table 13: Install Cottage Grove CGR TR03 – Summary of DER Solutions

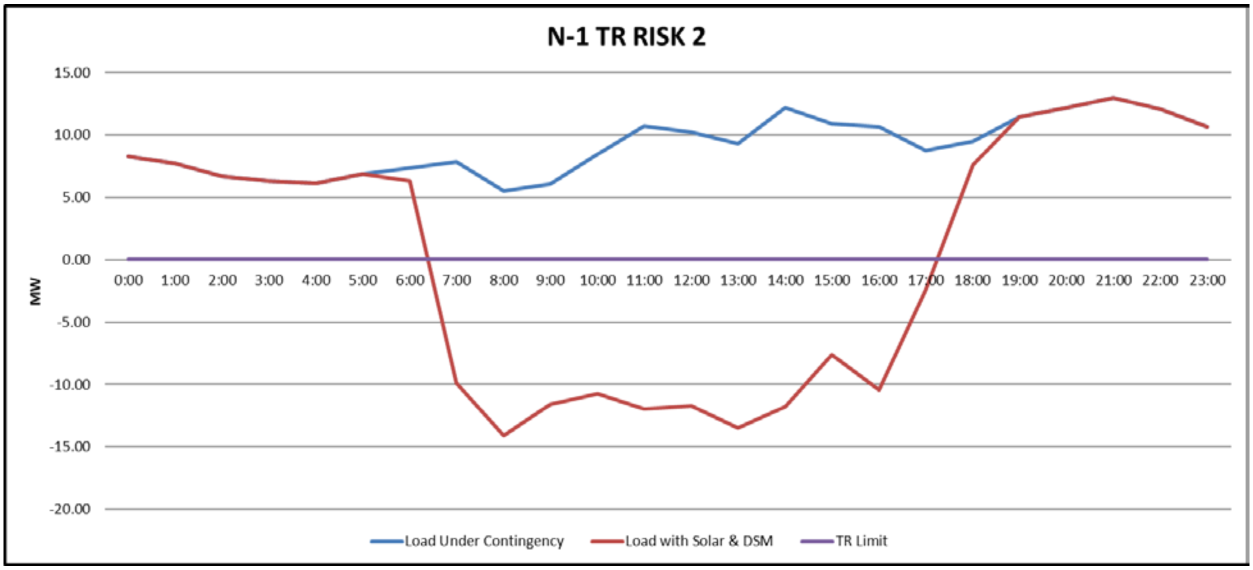
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-0 FDR RISK 1	2.15	5.00	Mitigated with optimal energy storage placement				
N-1 FDR RISK 1	5.25	35.93	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	12.9	88.48	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	21.99	95.99	0.0	14	8	18.2/ 103.1	$46,603,991
N-1 TR RISK 2	21.99	95.99	Mitigated with optimal energy storage placement				
Total			1.43	15	0	18.2/ 103.1	$46,603,991

K. Install Cannon Falls Trans CTF TR2 & Fdr

This project addresses four substation transformer risks; two of which are normal overloads, and two are due to contingency. The two transformers are each isolated in their own substations. In both cases, for loss of the single transformer some of the load can be transferred using feeder ties that tie to adjacent substations, but there is remaining load at risk that cannot be transferred. The traditional project in the budget involves the installation of a new transformer in the Cannon Falls Transmission substation and one additional feeder. The NWA solution for this project assumed that one energy storage device could be placed near each of the transformers in order to minimize the locations of deployment and solve the transformer risks.

Figure 11 shows the amount of load at risk for loss of one of the substation transformers associated with the project. The load curve shown in the figure has an abnormal shape due to existing hydro generation interconnected to the transformer.

Figure 11: Substation Transformer N-1 Contingency Load Risk



Based on the load curve, there would need to be energy storage installed that could discharge 12.98MW at peak, and 115.25 MWh of energy throughout the day
The transformer referenced in Fig. 10 is isolated and unable to transfer load to an adjacent transformer inside the substation. For this reason, the transformer limit is shown as zero. When observing the load curve (total load under contingency) it's important to understand that there would not be enough available capacity under the transformer limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, the assumption is that the battery would be charged and available for one day of use. For a multi-day event, the assumption is that the energy storage device would be used for the first 24 hours while a mobile transformer is being mobilized for after that. While this NWA does not equal the traditional solution in terms of availability for multi-day events, the NWA would address the risk for 24 hours. As stated earlier, by placing the energy storage unit near the substation, the N-0 risks are mitigated by sizing the energy storage device large enough to solve the N-1 risks.

Table 14: Install Cannon Falls Trans CTF TR2 & Fdr – Summary of DER Solutions

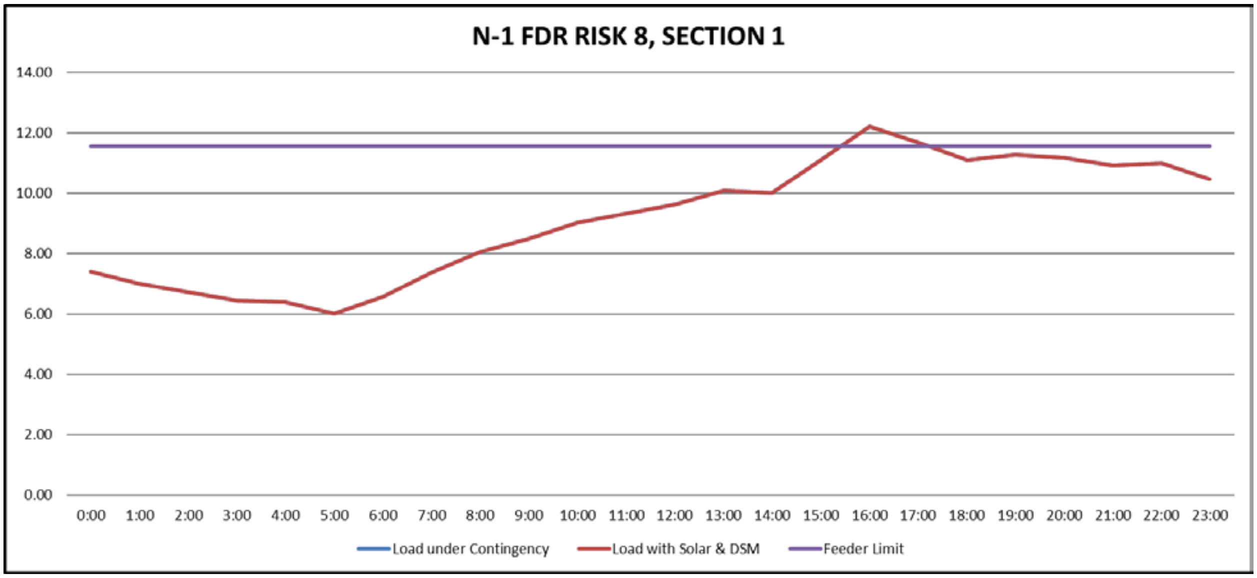
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-0 TR RISK 1	1.39	2.44	Mitigated with optimal energy storage placement				
N-0 TR RISK 2	0.92	3.18	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	2.15	20.25	0	0	8.7	2.15/20.25	$23,036,019
N-1 TR RISK 2	12.98	115.25	0	10.1	28	12.98/115.25	$87,207,945
Total			0	10.1	36.7	15.12/135.5	$110,243,964

L. Install Western WES TR3 & Feeders

This project has nine feeder risks, all of which are due to contingencies. The traditional project in the budget involves installing one new substation transformer, two feeder bays, and two new feeders at the Western substation. The NWA solution for this project involves placing energy storage systems and some new solar PV at strategic locations to mitigate risks and keep costs at a minimum. It is assumed that the energy storage systems could be strategically placed at feeder ties to mitigate all the feeder risks. The need for additional solar PV was identified in cases where there is not sufficient capacity available to charge the energy storage prior to when its discharge is needed.

Figure 12 shows an example of the amount of load at risk for loss of one of the feeders associated with the project.

Figure 12: Feeder N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could discharge 0.65 MW at peak, and 0.76 MWh of energy throughout the day. This energy storage system would solve this section's contribution to the feeder N-1 risk. While there are only 9 feeder contingency risks to be addressed by the project, 21 different feeder transfer scenarios were analyzed for the NWA due to several of the feeder contingency risks consisting of multiple sections with load at risk. Ten of these section transfer scenarios were determined to be unnecessary assuming a single energy storage unit could be placed at an optimal location to mitigate multiple risks.

Install Western WES TR3 & Feeders – Summary of DER Solutions

Table 15:

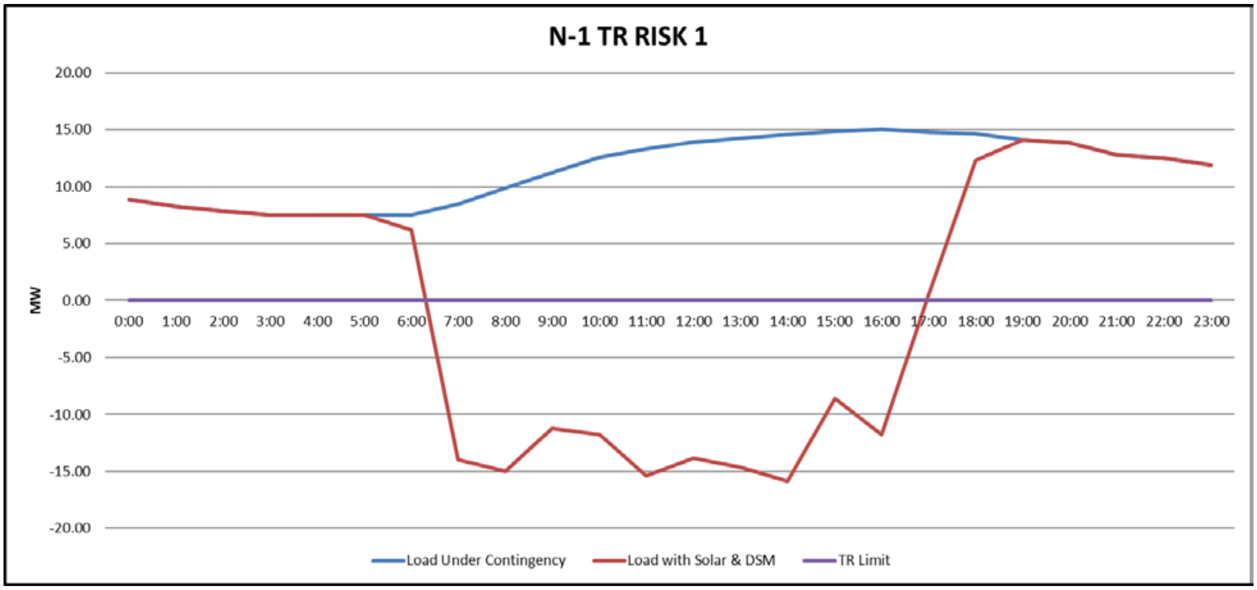
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	4.92	30.82	0.00	0.13	0.00	4.92/30.82	$9,367,703
N-1 FDR RISK 2	2.30	14.53	Mitigated with optimal energy storage placement				
N-1 FDR RISK 3	1.56	4.00	Mitigated with optimal energy storage placement				
N-1 FDR RISK 4	2.15	17.91	0.00	0.00	3.10	2.15/17.91	$11,315,381
N-1 FDR RISK 5	3.29	19.44	0.00	0.00	7.00	3.29/19.44	$19,918,358
N-1 FDR RISK 6	2.90	13.83	0.00	0.00	0.00	2.90/13.83	$4,508,799
N-1 FDR RISK 7	8.98	44.65	0.00	0.18	15.50	8.98/44.65	$45,344,240
N-1 FDR RISK 8	0.65	0.76	0.00	0.00	0.00	0.65/0.76	$685,796
N-1 FDR RISK 9	2.82	11.76	0.00	0.00	0.00	2.82/11.76	$4,266,861
Total			0.00	0.30	25.60	25.71/139.17	$95,407,138

M. Reinforce Faribault FAB TR1

This project has three feeder risks and two substation transformer risks, all of which are due to contingency. The two substation transformers are not electrically tied together, therefore we treat them as two individual units in the analysis. In both cases, for loss of the single transformer some of the load can be transferred using feeder ties that tie to adjacent substations, but there is remaining load at risk that cannot be transferred. The traditional project in the budget involves upgrading a transformer and installing a bus tie between the two transformers at the Faribault substation.

The NWA solution for this project involves existing solar generation on the feeders at the Faribault substation combined with new energy storage. It was assumed that the energy storage systems could be strategically placed to mitigate the feeder and bank contingencies. Figure 13 shows the amount of load at risk for loss of one of the substation transformers associated with the project.

Figure 13: Substation Transformer N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could discharge 14.12 MW at peak and 131.72 MWh of energy throughout the day.

The transformer referenced in Figure 13 is isolated and unable to transfer load to an adjacent transformer inside the substation. For this reason, the transformer limit is shown as zero. When observing the load curve (total load under contingency) it's important to understand that there would not be enough available capacity under the transformer limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, the assumption is that the battery would be charged and available for one day of use. For a multi-day event, the assumption is that the energy storage device would be used for the first 24 hours while a mobile transformer is being mobilized for after that. While this NWA does not equal the traditional solution in terms of availability for multi day events, the NWA would address the risk for 24 hours.

Table 16: Reinforce Faribault FAB TR1 – Summary of DER Solutions

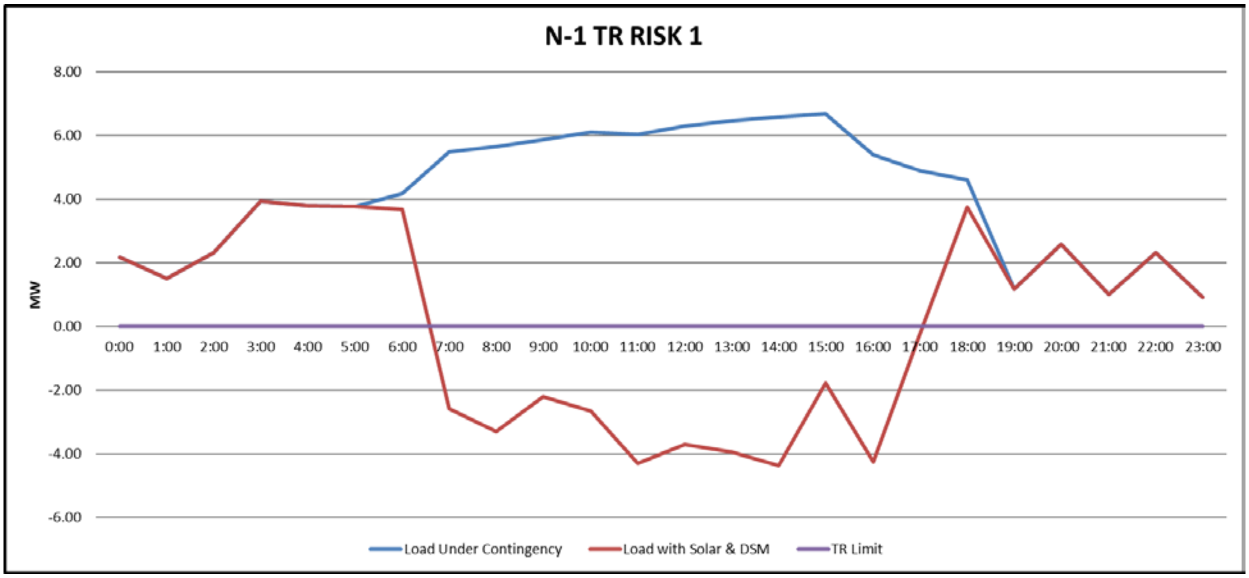
Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	2.51	6.40	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	1.74	8.33	Mitigated with optimal energy storage placement				
N-1 FDR RISK 3	2.79	18.05	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	14.12	131.72	0	3.1	45.25	14.12/131.72	$125,845,012
N-1 TR RISK 2	14.12	69.81	Mitigated with optimal energy storage placement				
Total			0	3.1	45.25	14.12/131.72	$125,845,012

N. Install East Winona EWI TR2

This project addresses four feeder risks and two transformer risks. One of the feeder risks is due to a normal overload, and the remaining three feeder risks as well as the two transformer risks are due to contingencies. The two transformers are each isolated in their own substations. In both cases, for loss of the single transformer some of the load can be transferred using feeder ties that tie to adjacent substations, but there is remaining load at risk that cannot be transferred. The traditional project in the budget involves installing a new transformer in the East Winona substation and one additional feeder.

The NWA solution for this project involves placing energy storage systems at strategic locations to mitigate risks and keep costs at a minimum. It was assumed that the energy storage systems could be strategically placed at feeder ties to mitigate the contingencies and normal overload. Figure 14 shows the amount of load at risk for loss of one of the substation transformers associated with the project.

Figure 14: Substation Transformer N-1 Contingency Load Risk



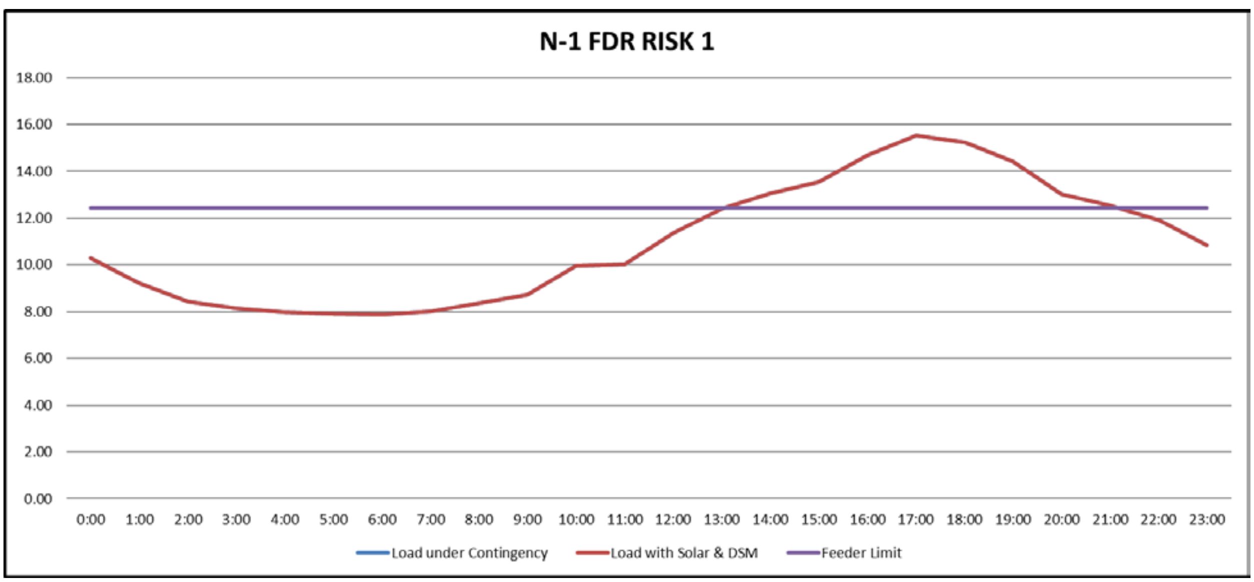
In the current condition, there would need to be energy storage installed that would be capable of reaching 3.95MW at peak and discharging 32.95 MWh of energy throughout the day. The transformer referenced in Figure 14 is isolated and unable to transfer load to an adjacent transformer inside the substation or anywhere on our system. For this reason, the transformer limit is shown as zero. When observing the load curve (total load under contingency) it's important to understand that there would not be enough available capacity under the transformer limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, the assumption is that the battery would be charged and available for one day of use. For a multi-day event, the assumption is that the energy storage device would be used for the first 24 hours while a mobile transformer is mobilized for use after that. While this NWA does not equal the traditional solution in terms of availability for multi day events, the NWA would address the risk for 24 hours.

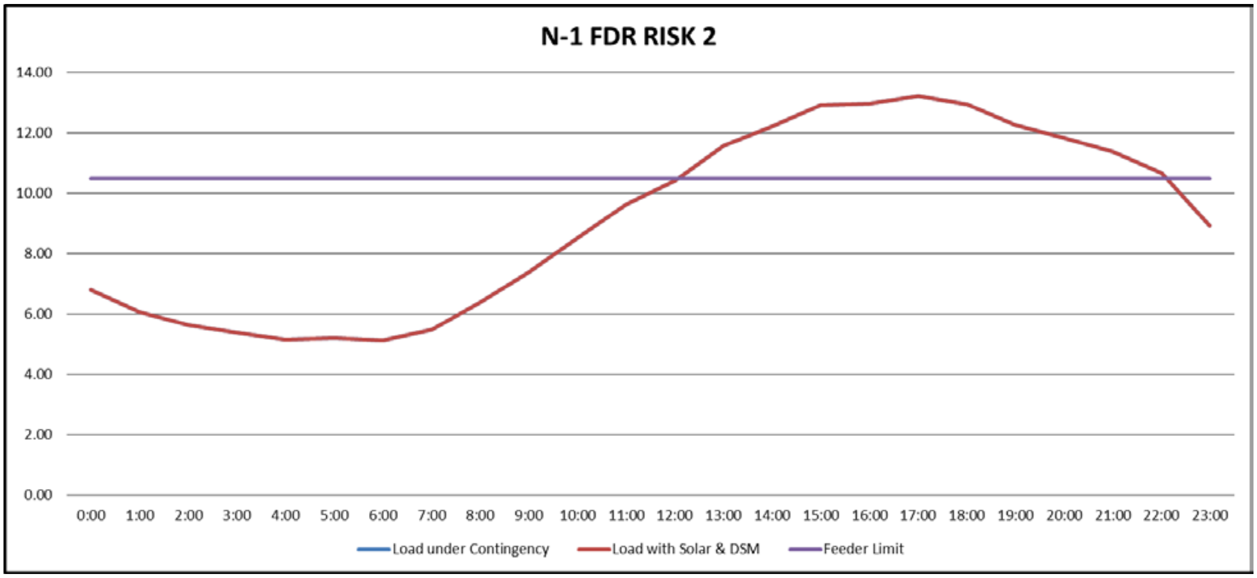
Table 17: Install East Winona EWI TR2 – Summary of DER Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution				Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-0 FDR RISK 1	0.87	1.80	Mitigated with optimal energy storage placement				
N-1 FDR RISK 1	2.31	11.90	Mitigated with optimal energy storage placement				
N-1 FDR RISK 2	3.82	22.13	Mitigated with optimal energy storage placement				
N-1 FDR RISK 3	6.90	41.58	Mitigated with optimal energy storage placement				
N-1 TR RISK 1	3.95	32.95	0	0	17.4	3.95/32.95	$43,997,624
N-1 TR RISK 2	3.95	56.10	0	0	29.6	6.9/56.10	$74,756,357
Total			0	0	47	10.85/89.06	$115,553,981

IV. LOAD CURVES

A. Install Kohlman Lake KOL Feeder

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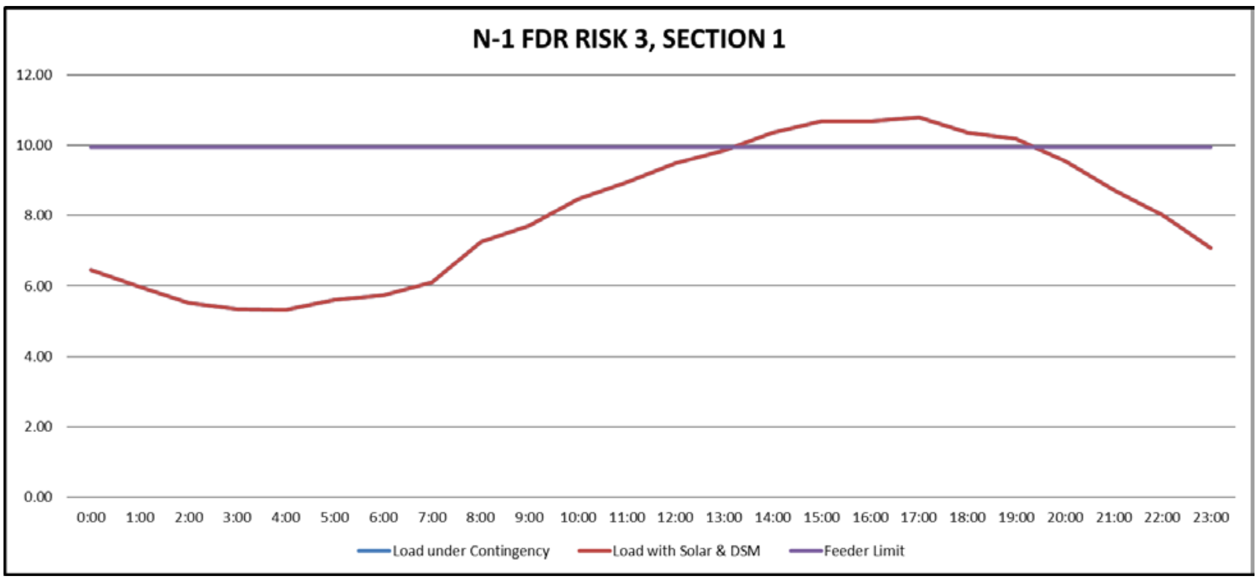
Load under Contingency
Load with Solar & DSM
Feeder Limit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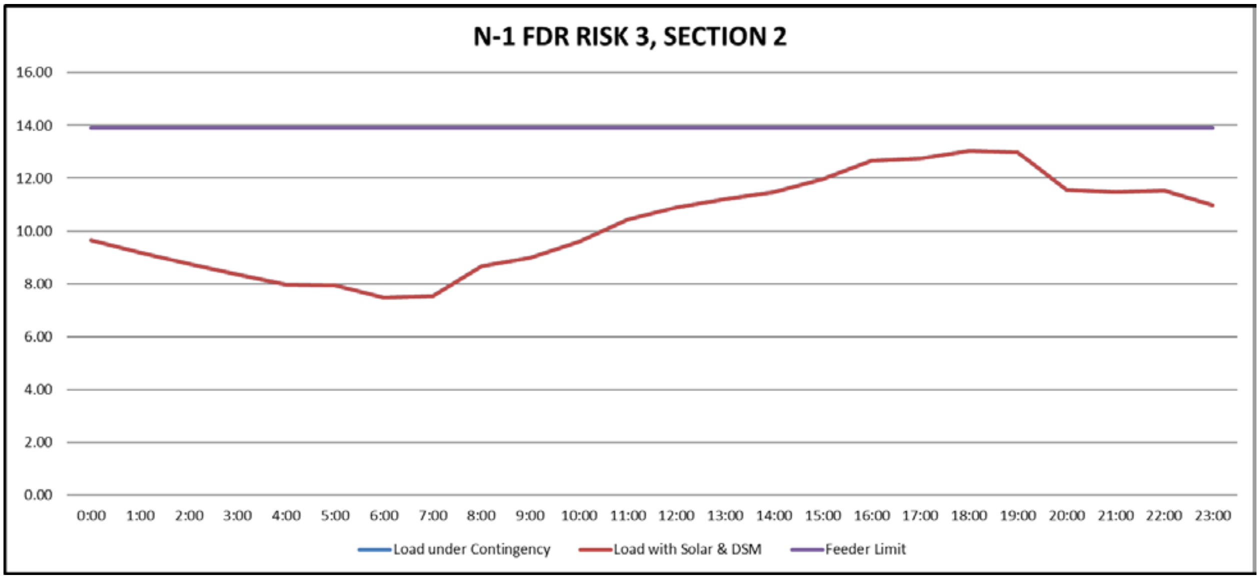
Load under Contingency
Load with Solar & DSM
Feeder Limit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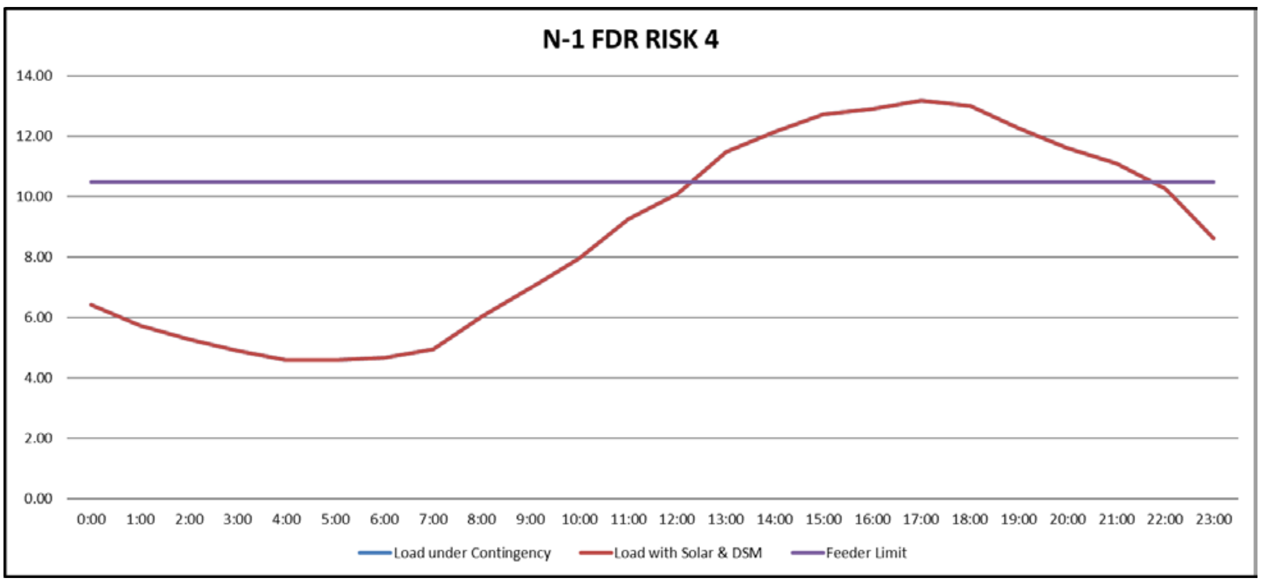
Load under Contingency
Load with Solar & DSM
Feeder Limit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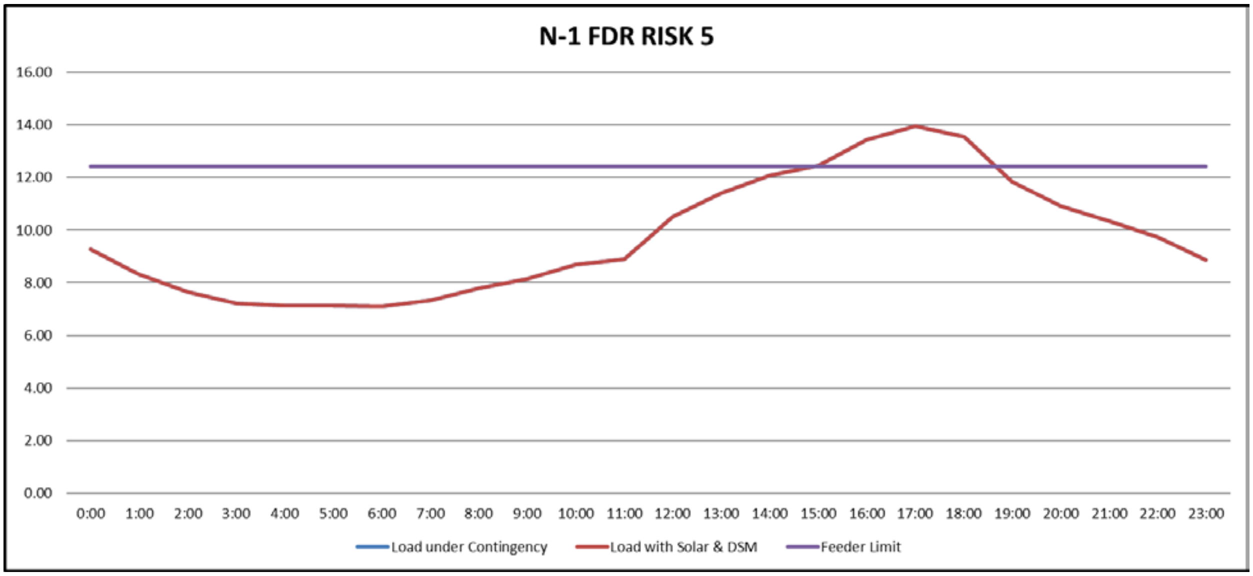
Load under Contingency
Load with Solar & DSM
Feeder Limit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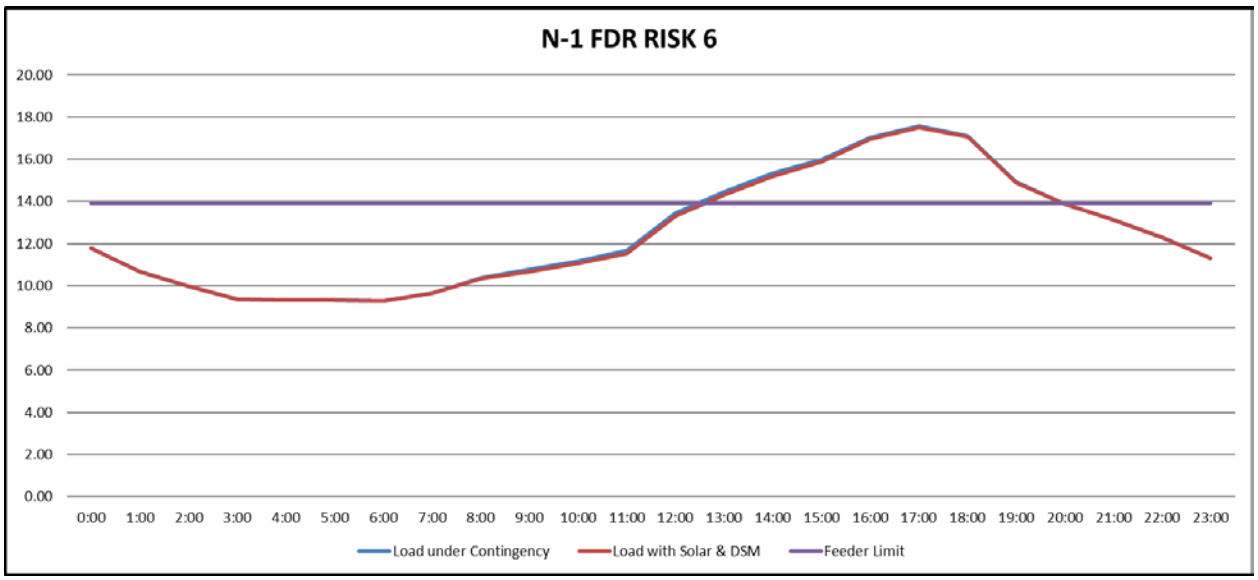
Load under Contingency
Load with Solar & DSM
Feeder Limit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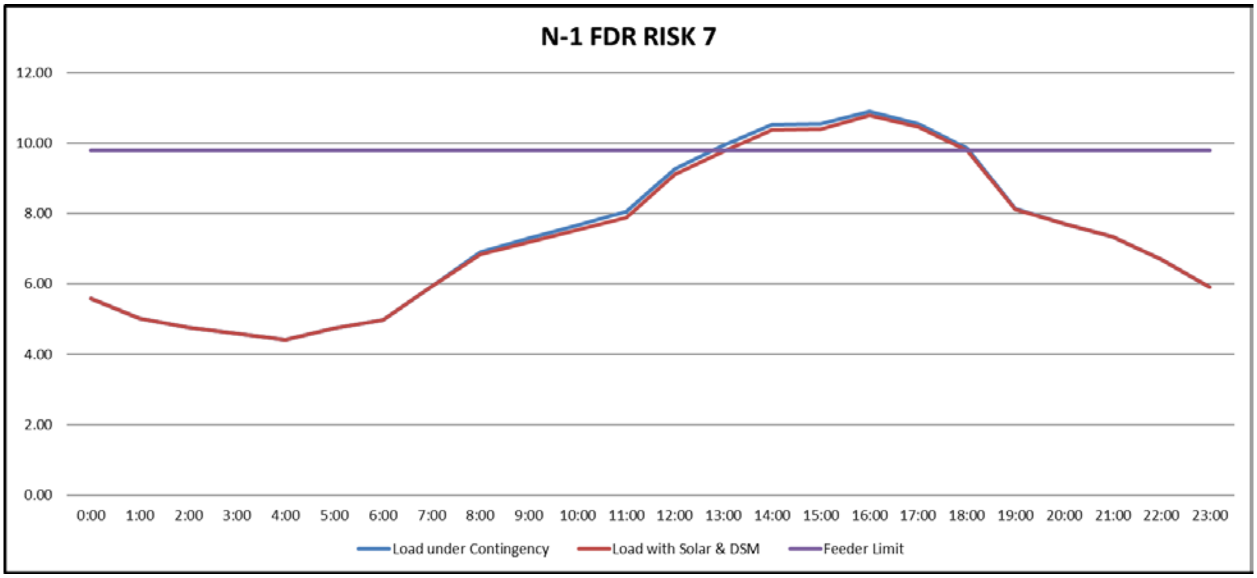
Load under Contingency
Load with Solar & DSM
Feeder Limit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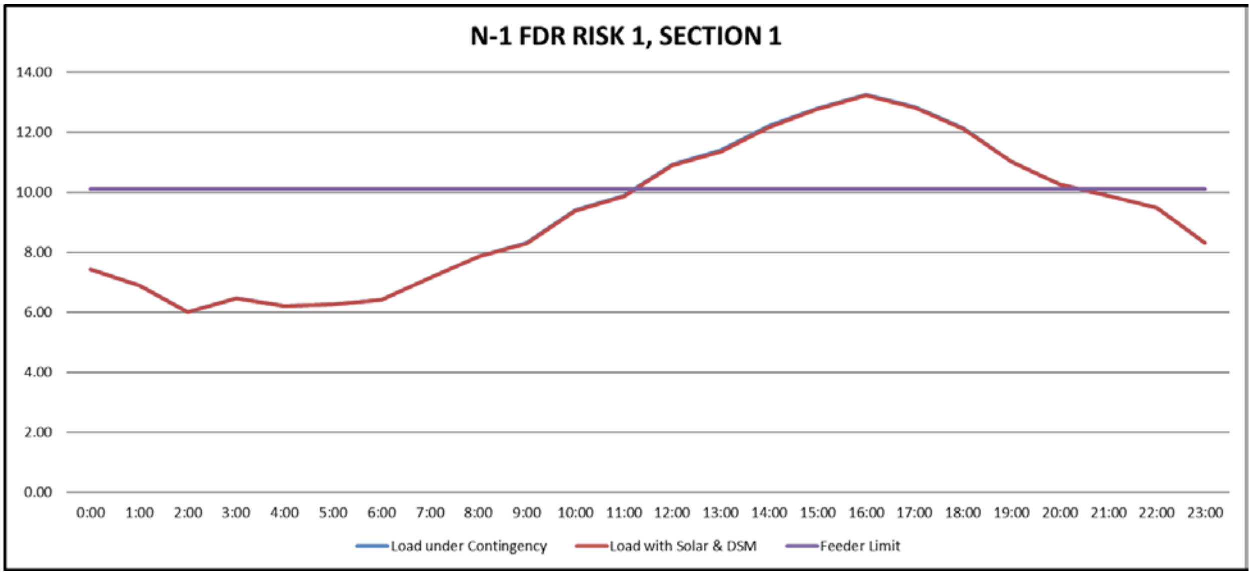
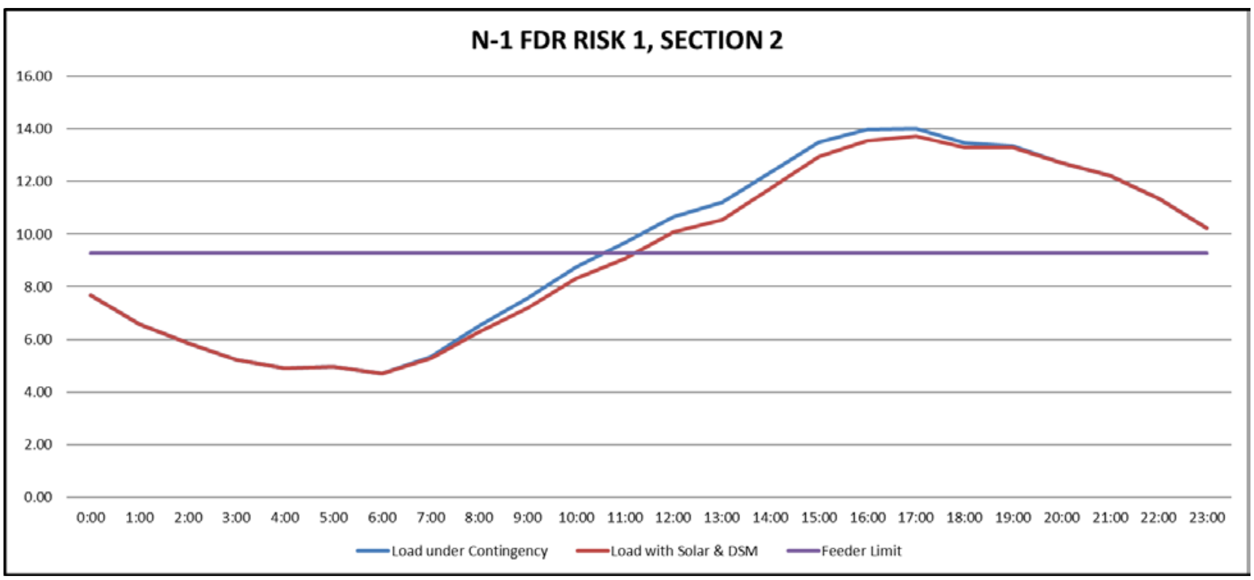
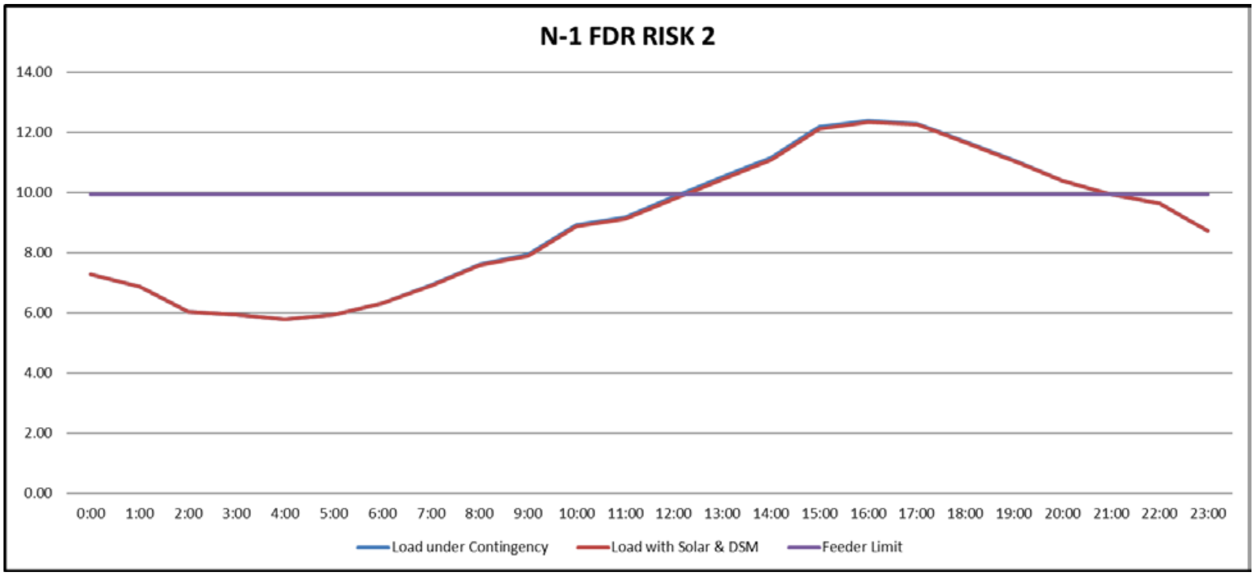
Load under Contingency
Load with Solar & DSM
Feeder Limit

B. Install Viking VKG Feeder



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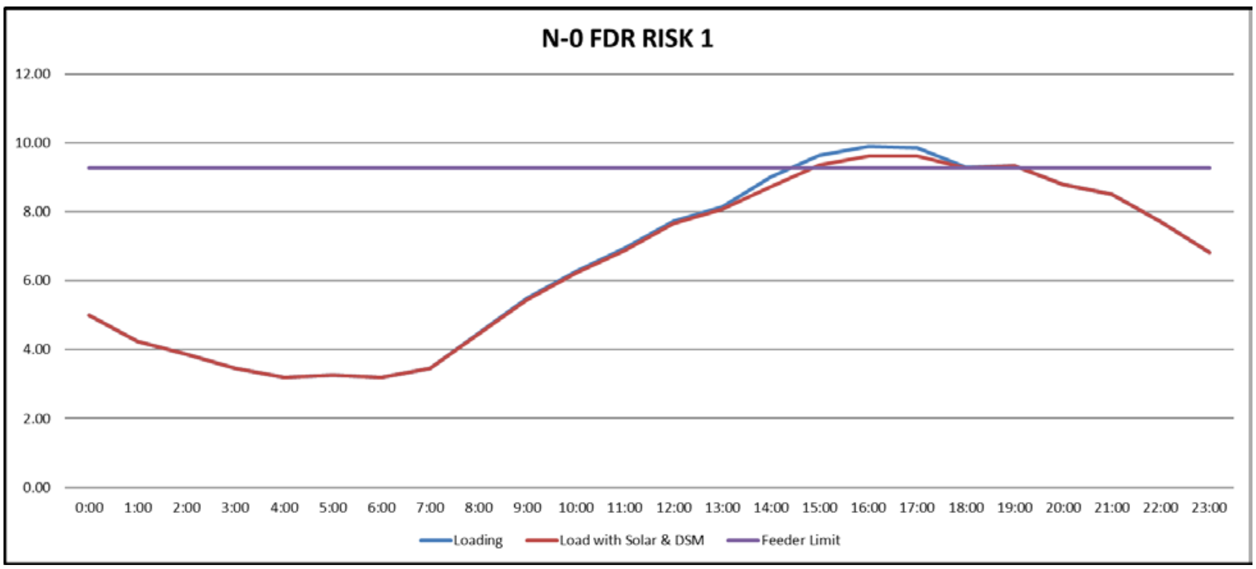
Load with Solar & DSM
Feeder Limit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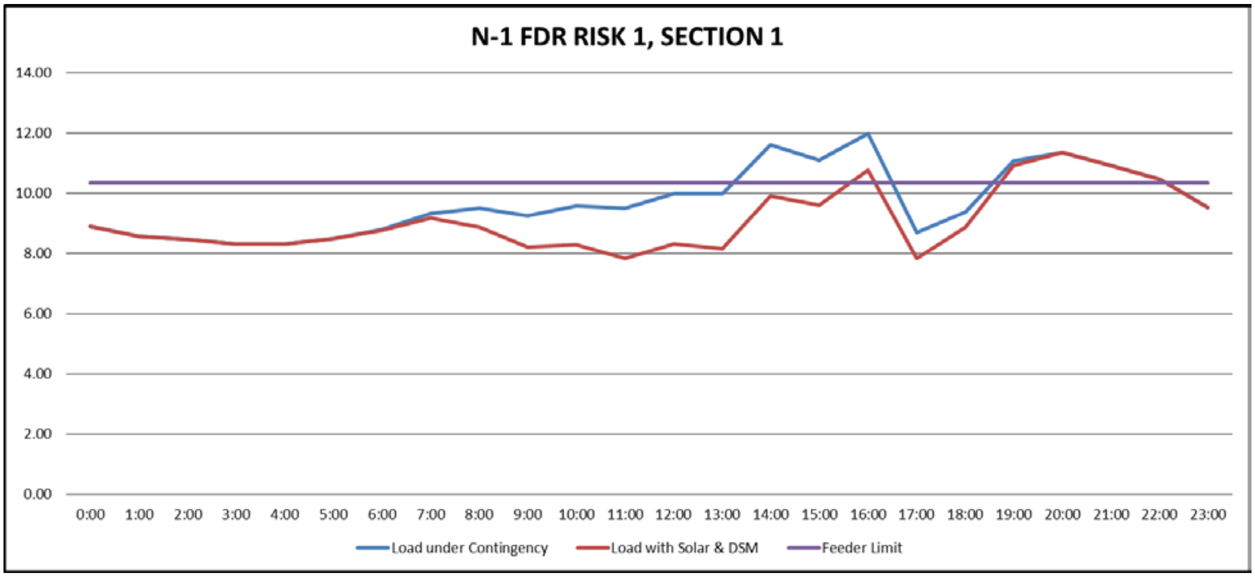
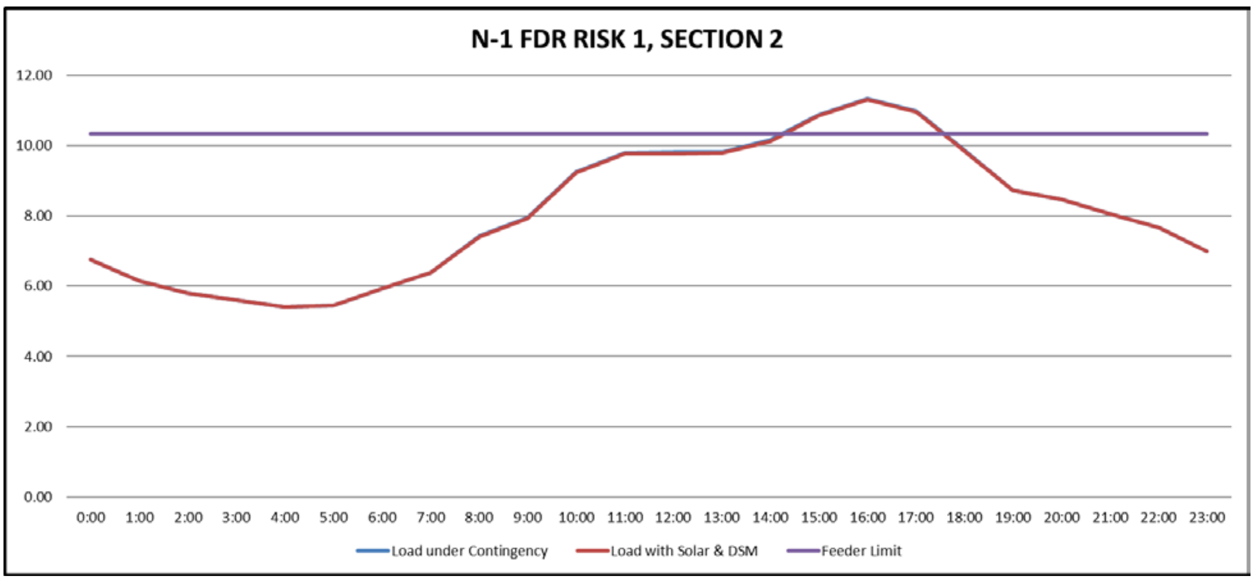
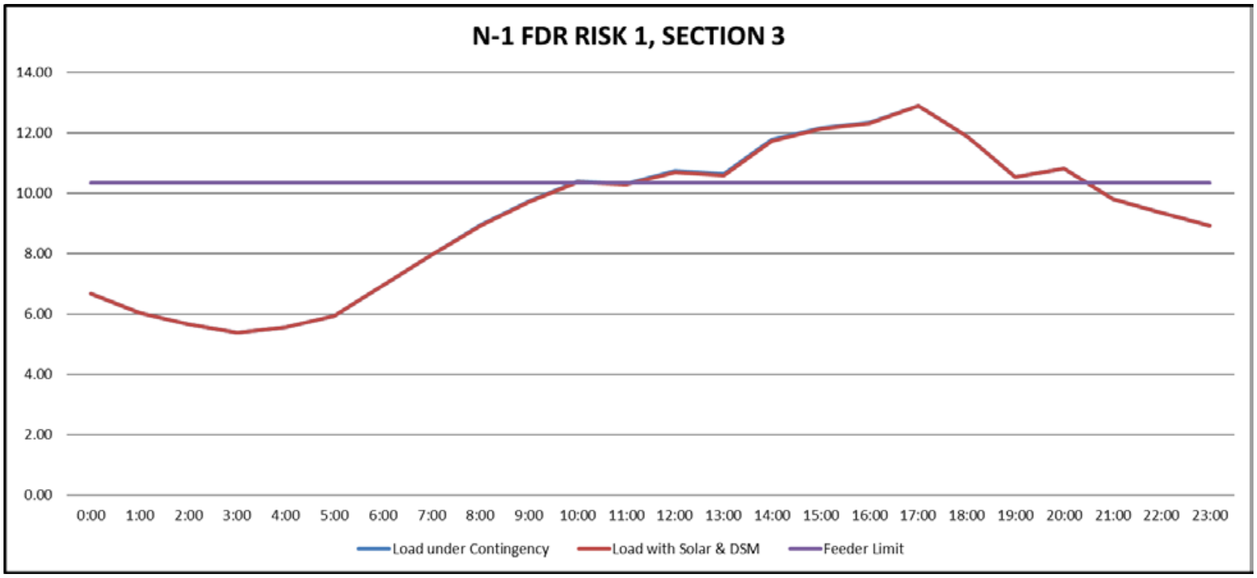
Loading
Load with Solar & DSM
Feeder Limit

C. Install Wyoming WYO Feeder



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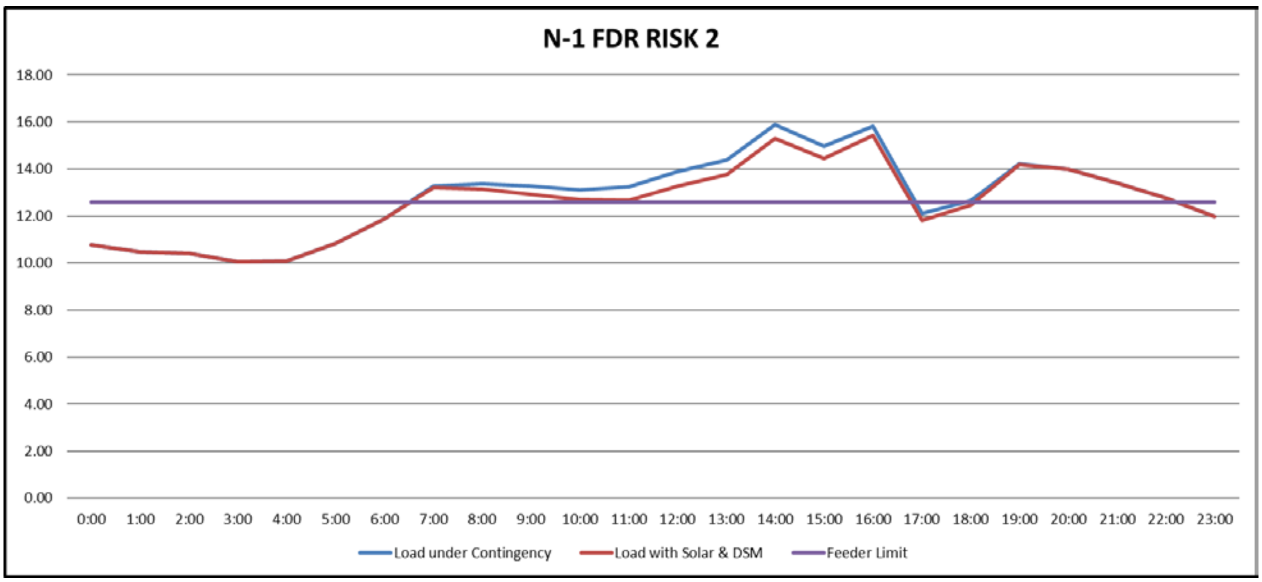
Load under Contingency
Load with Solar & DSM
Feeder Limit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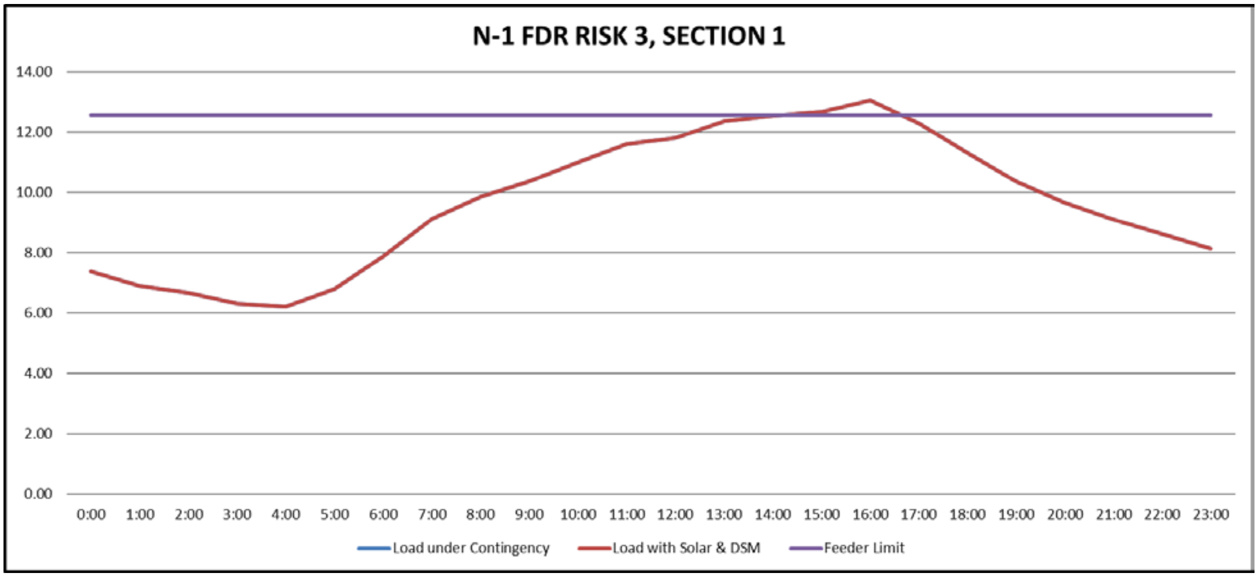
Load with Solar & DSM
Feeder Limit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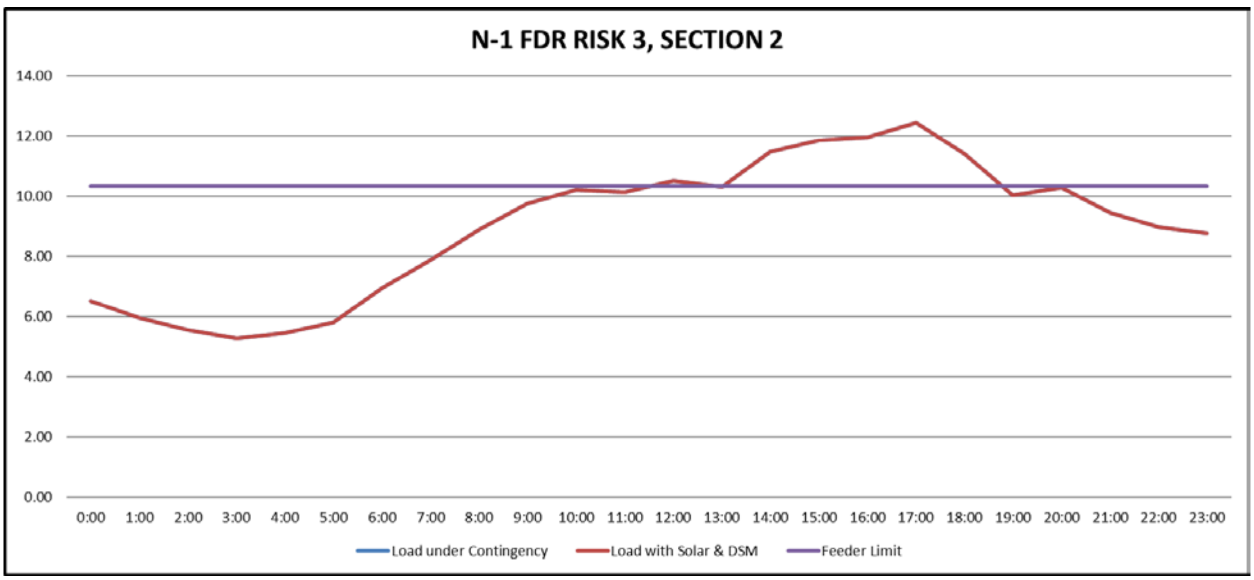
Load with Solar & DSM
Feeder Limit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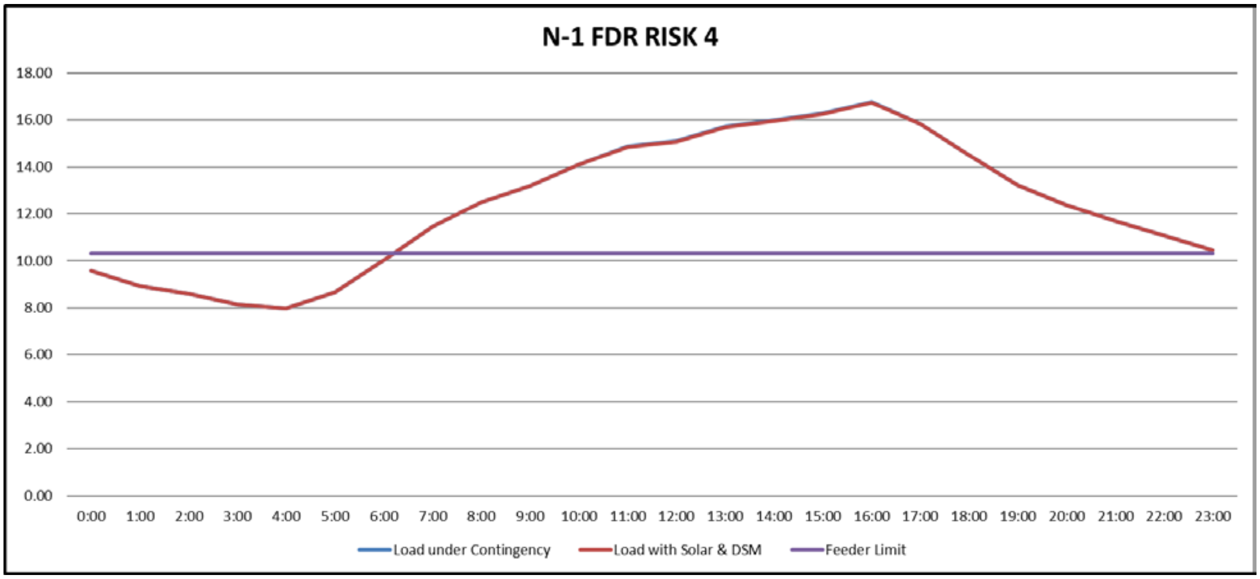
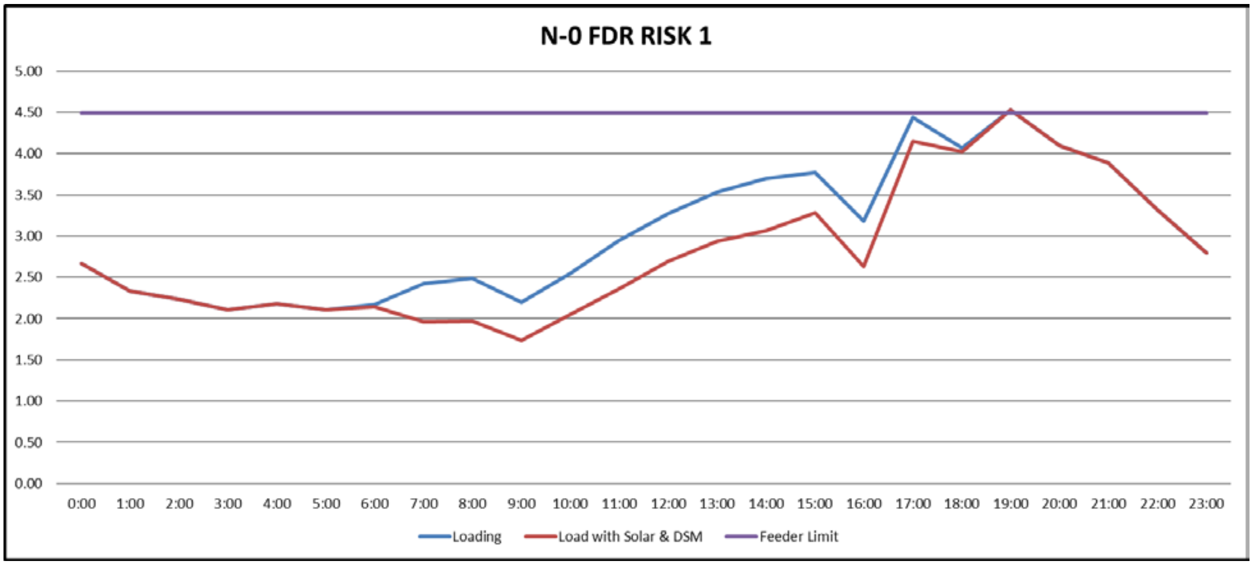
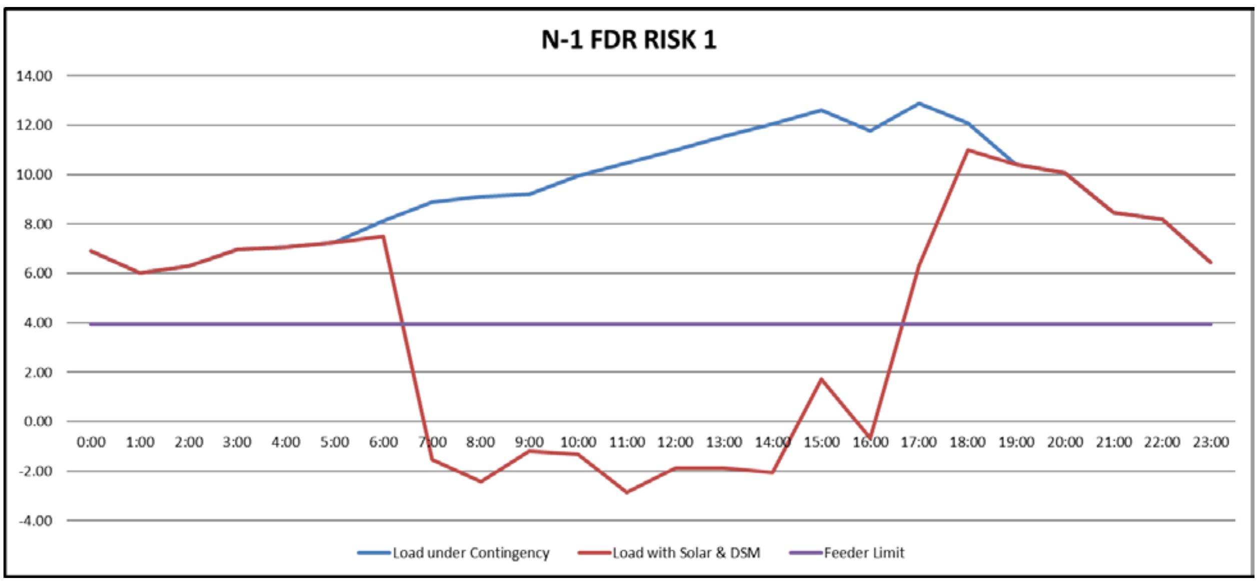
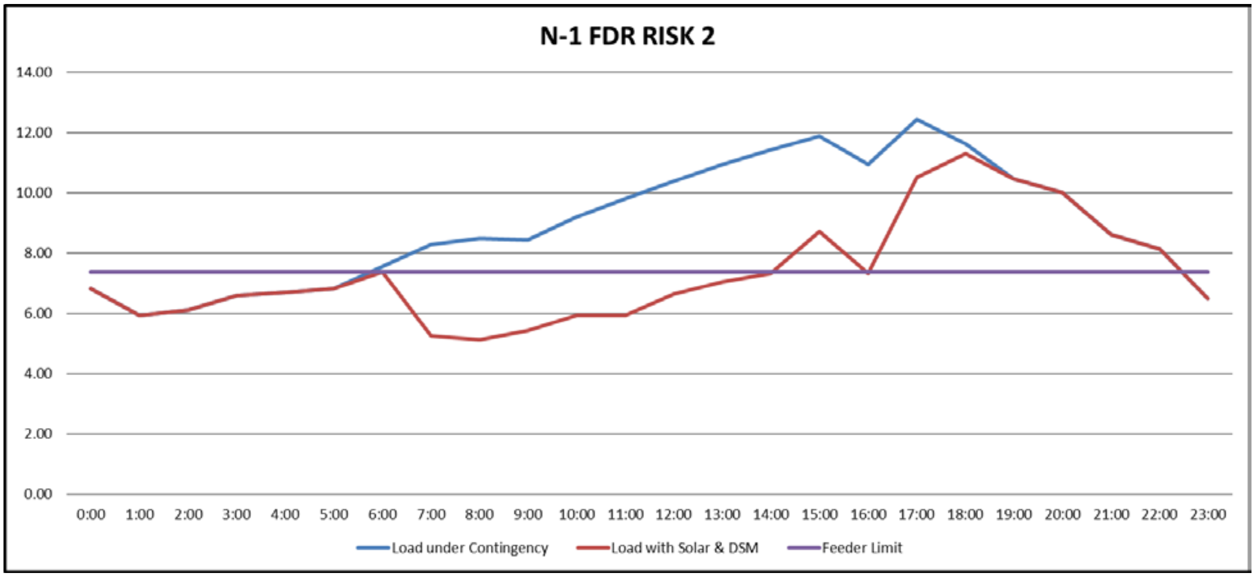
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 4
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

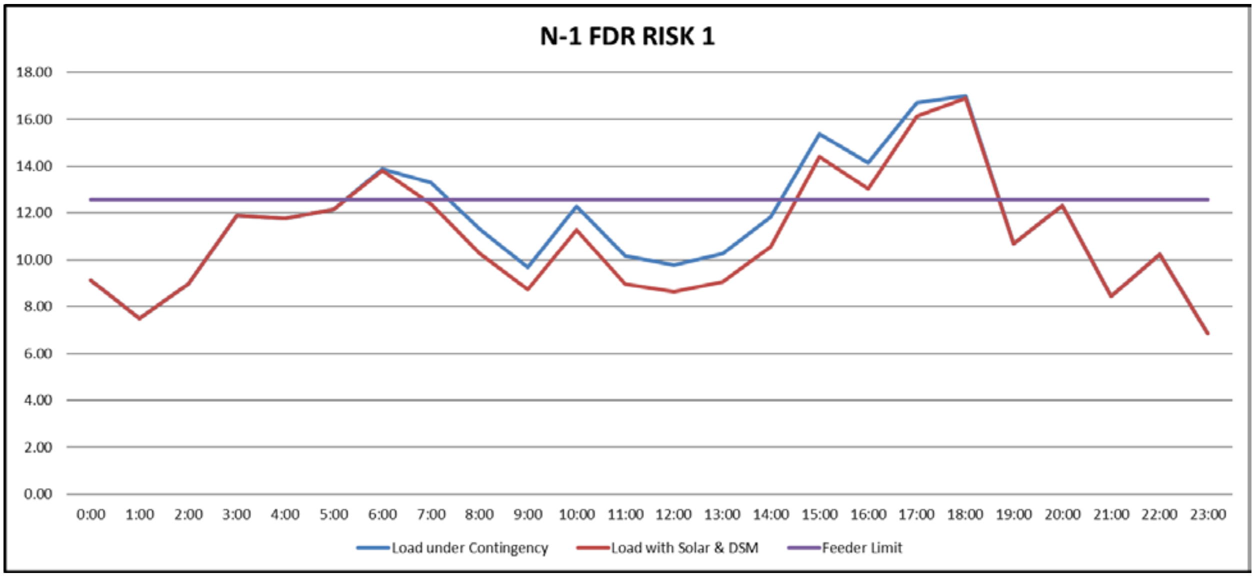
D. Install Veseli VES TR1 & Feeder

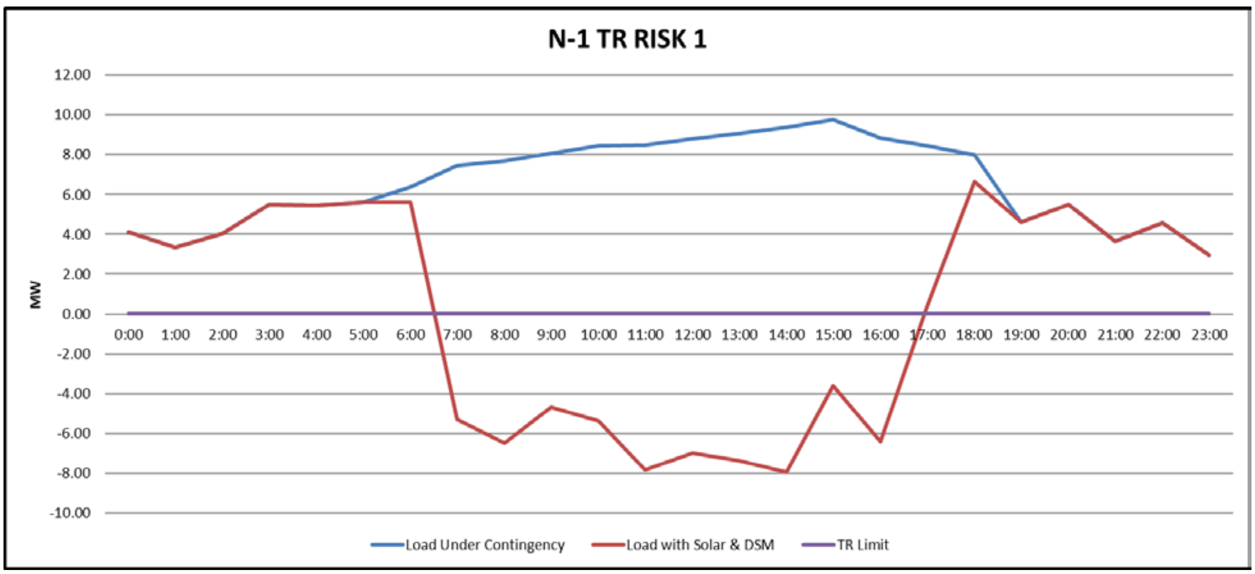




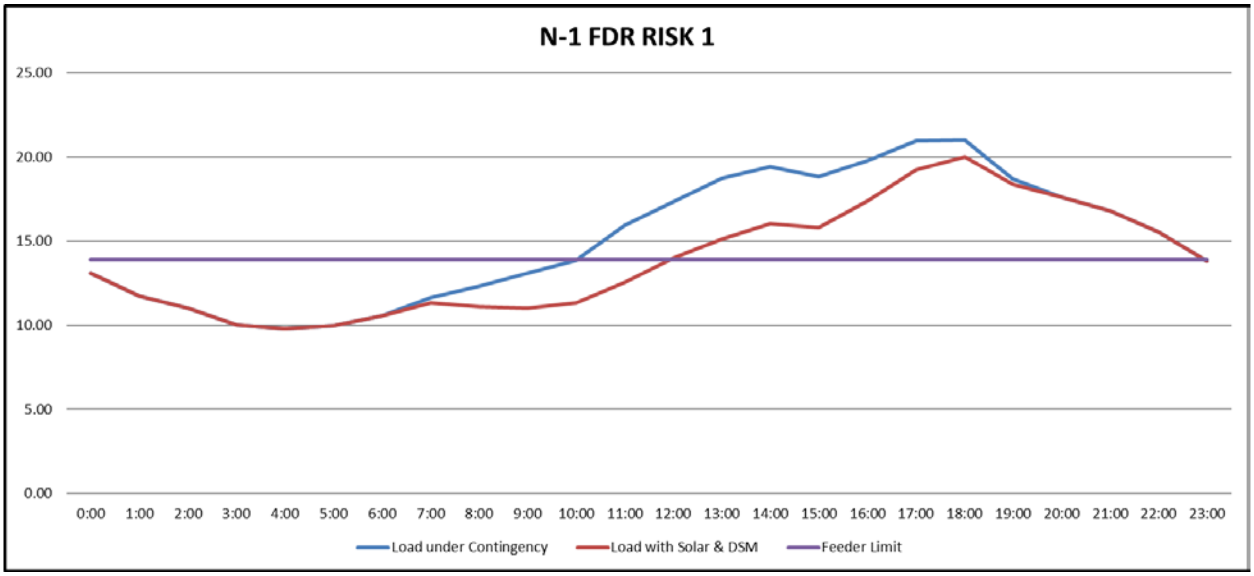

N-1 FDR RISK 2
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

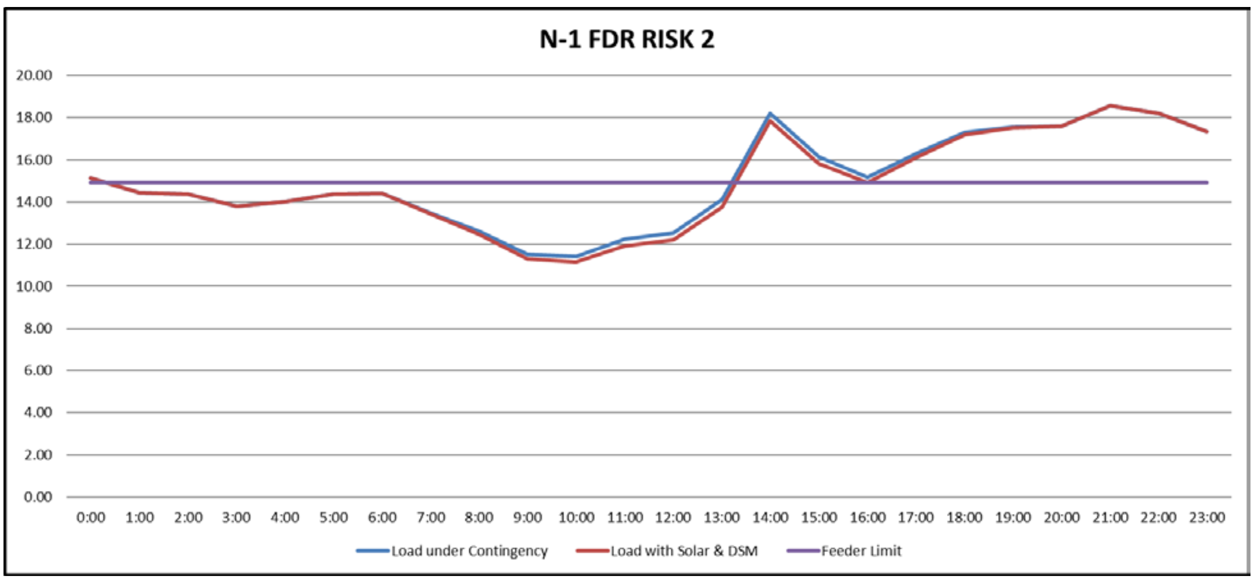
E. Install Zumbrota ZUM TR2

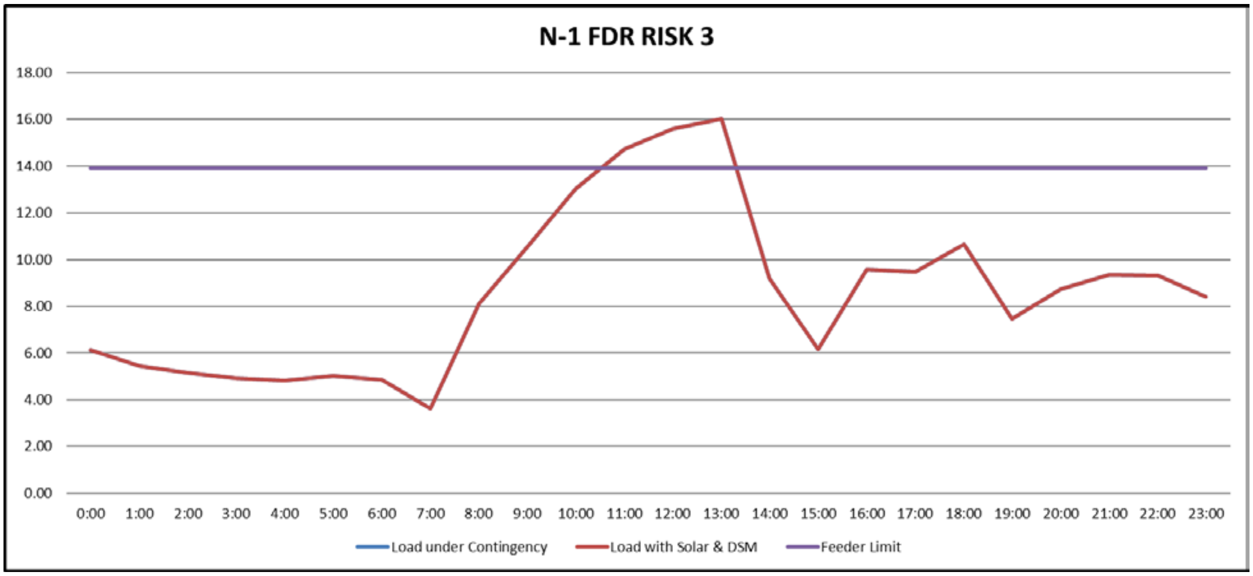


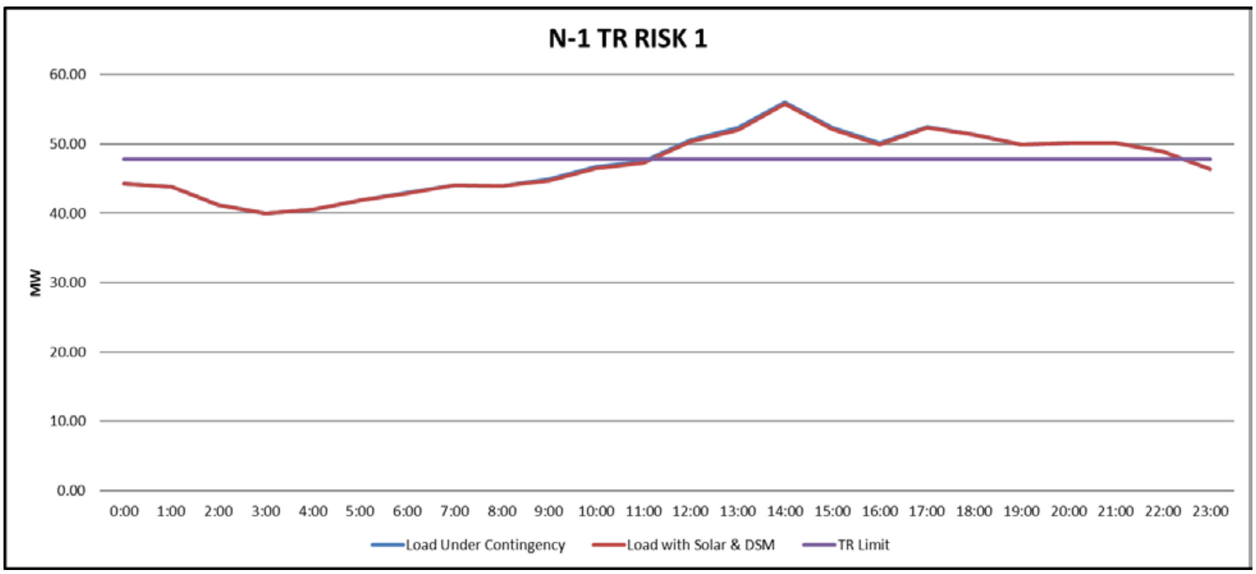


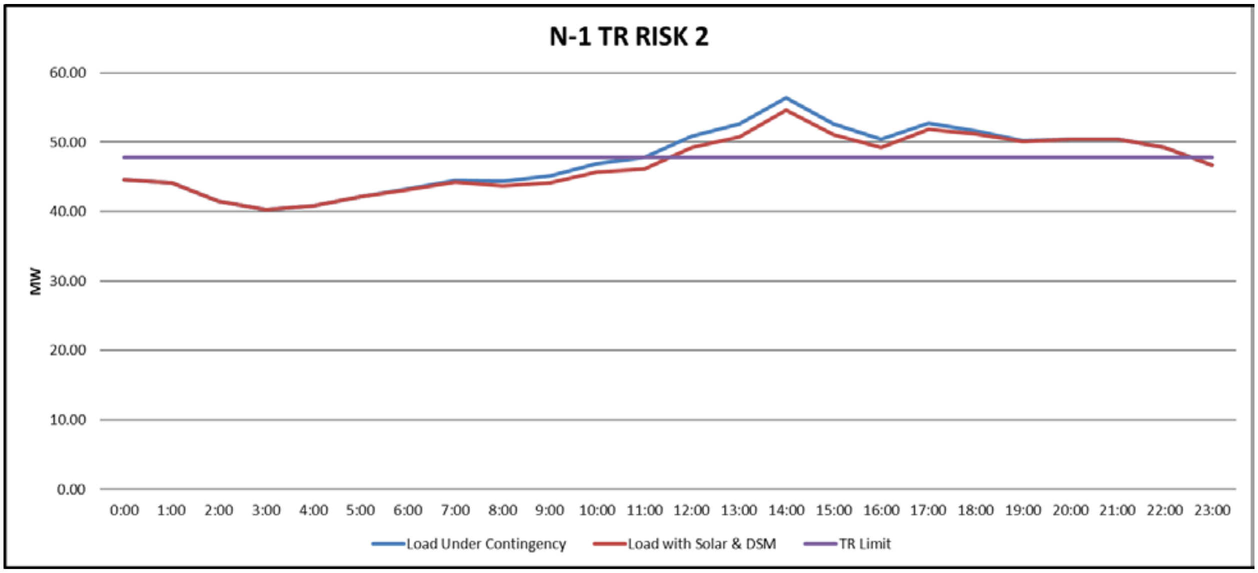
F. Install Chemolite CHE TR03



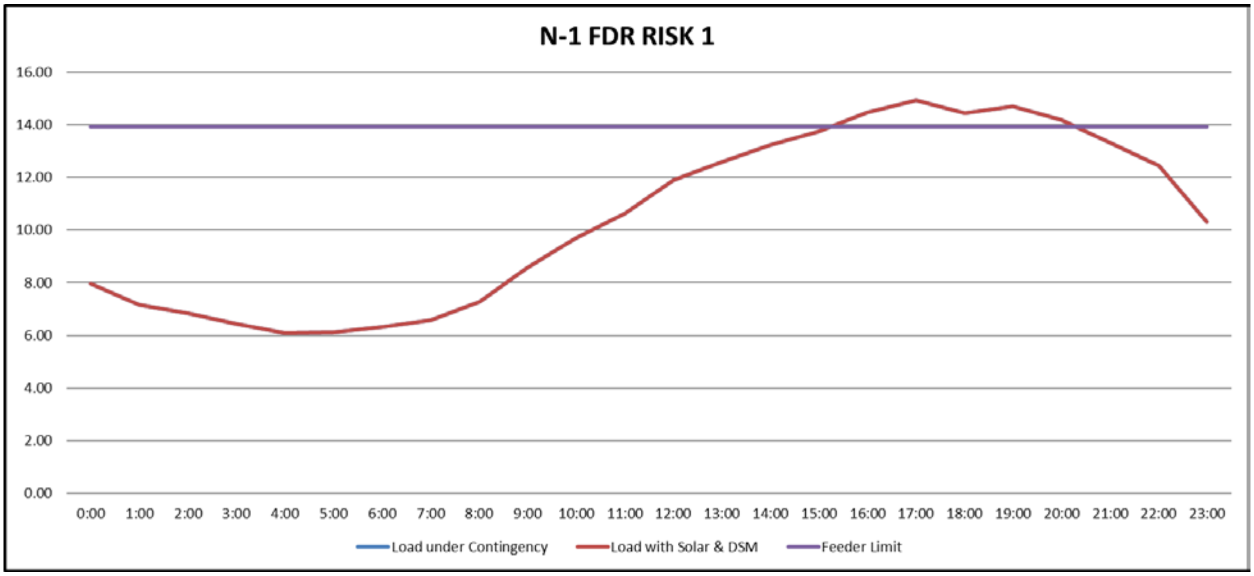


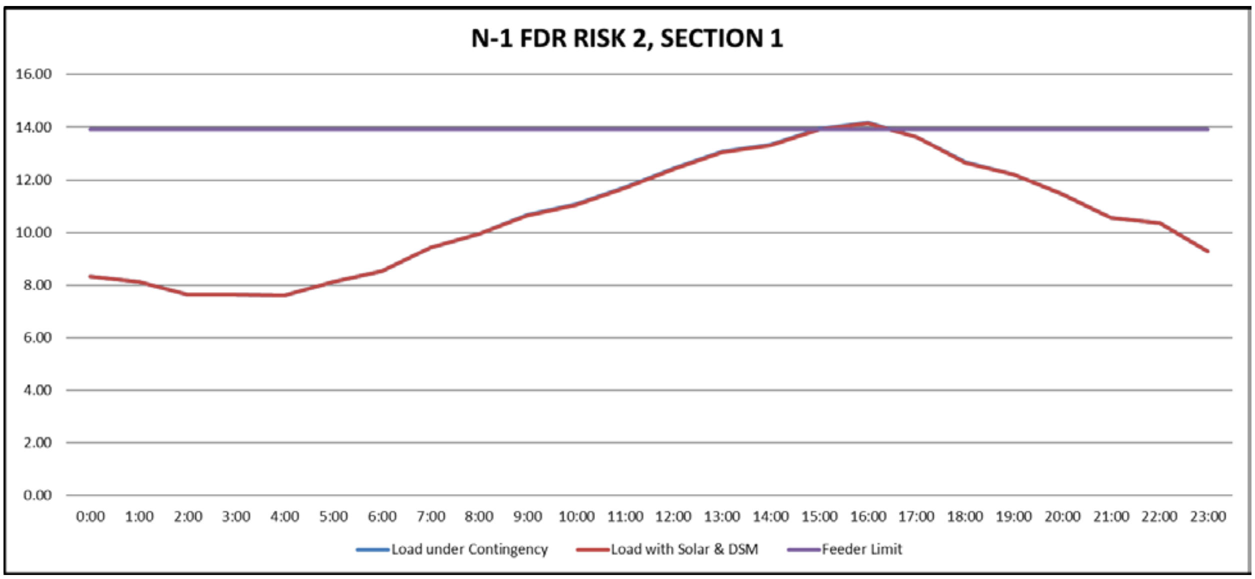

N-1 FDR RISK 3
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

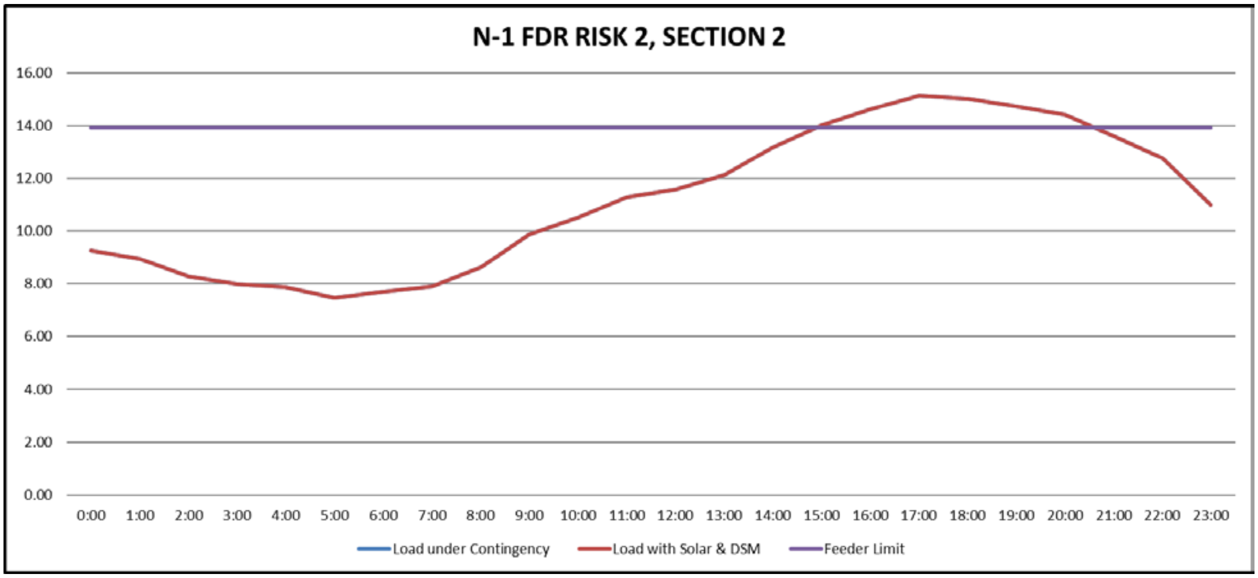

N-1 TR RISK 1
MW
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

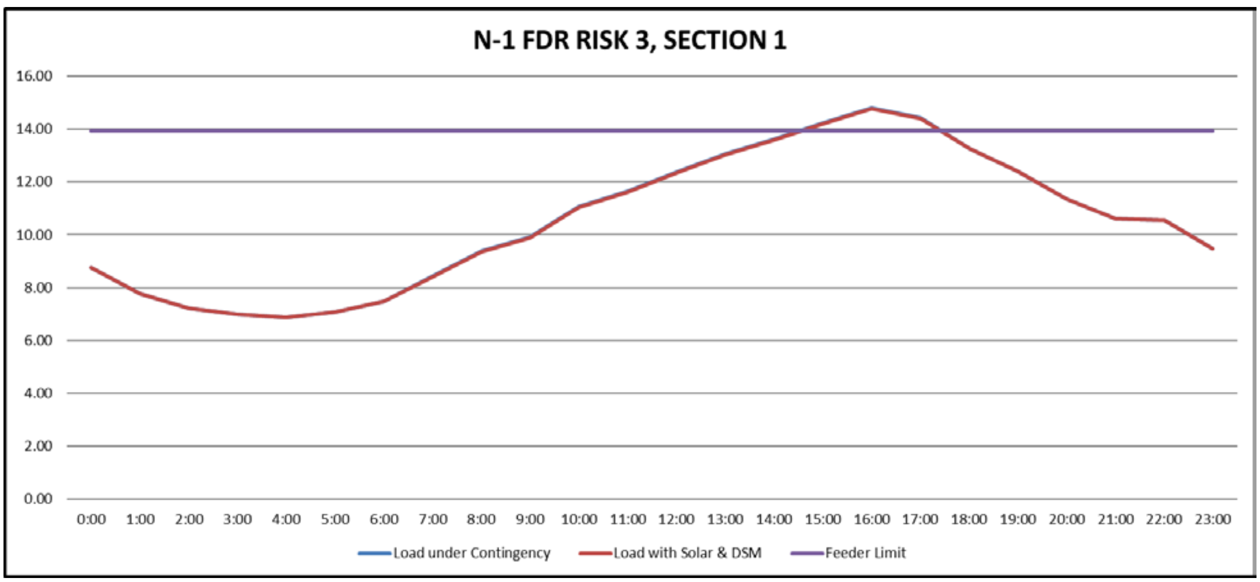

N-1 TR RISK 2
MW
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

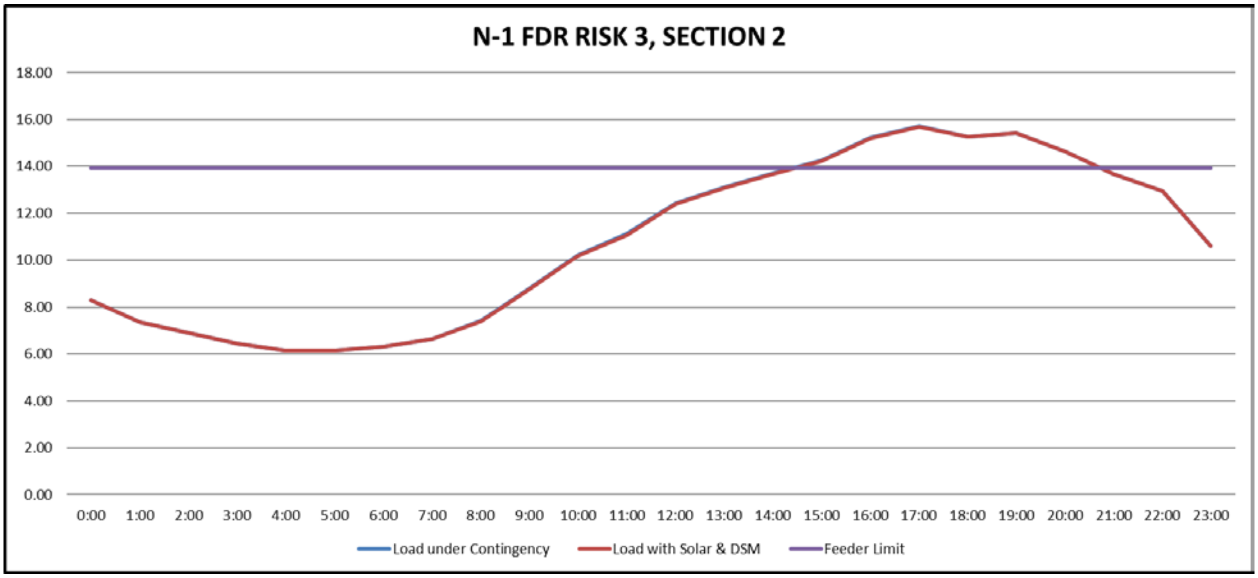
G. Install Goose Lake GLK TR3 & Feeders

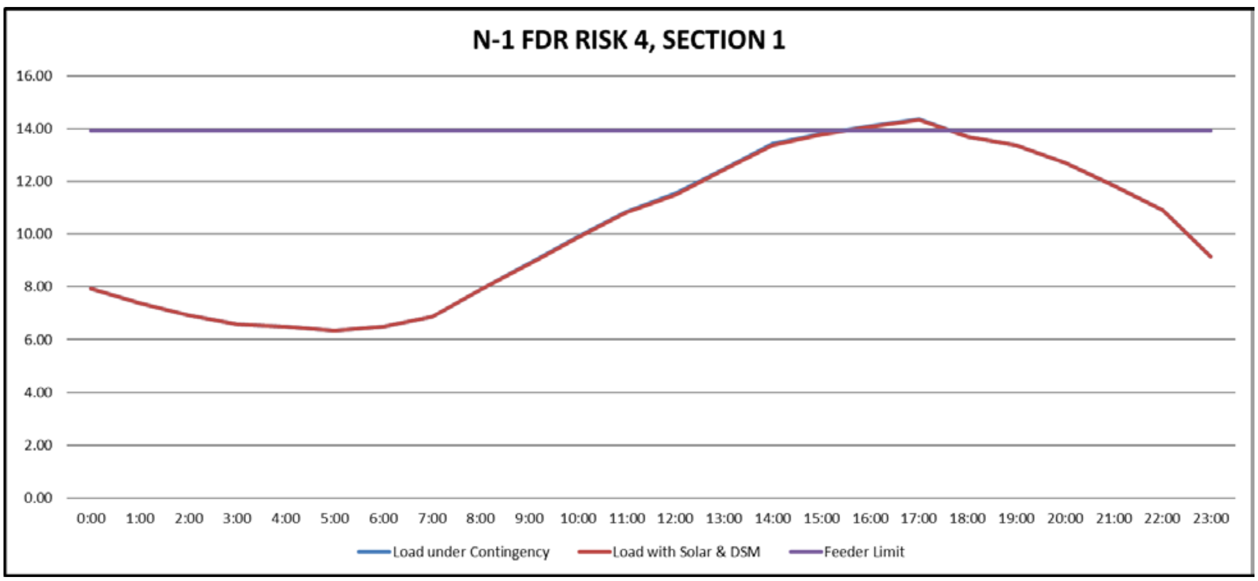


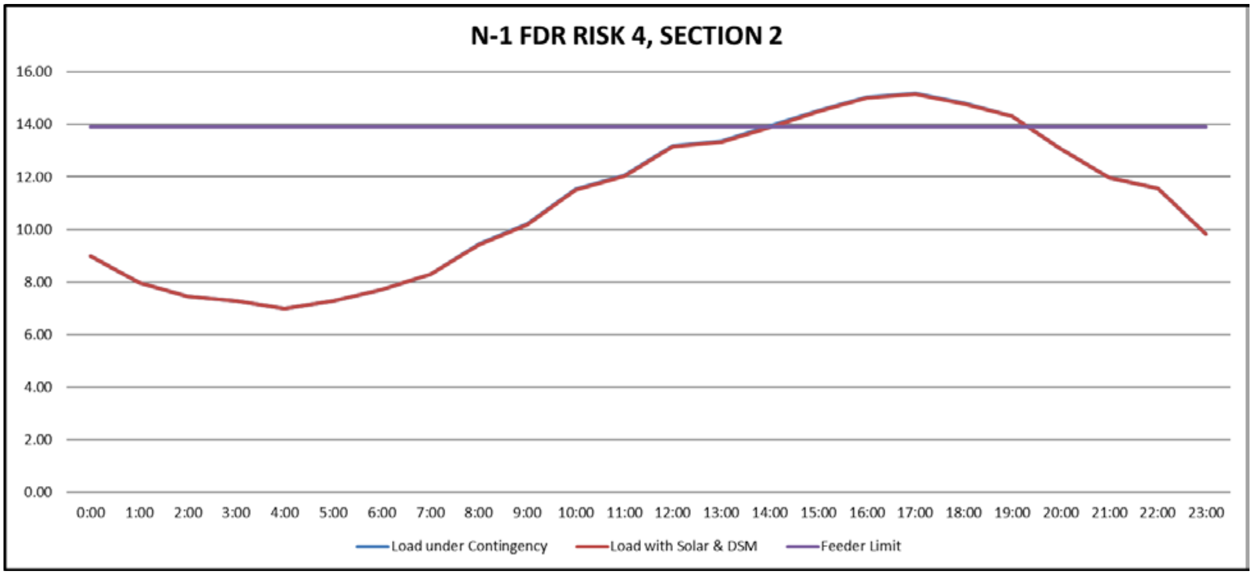


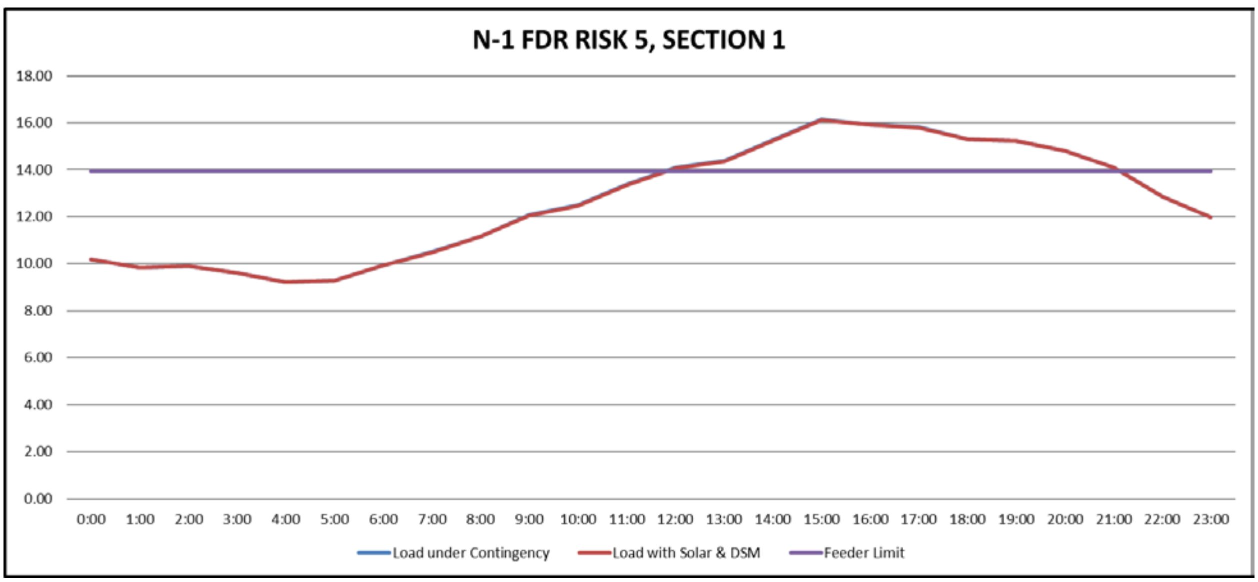

N-1 FDR RISK 2, SECTION 2
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 3, SECTION 1
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 3, SECTION 2
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 4, SECTION 1
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 4, SECTION 2
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 5, SECTION 1
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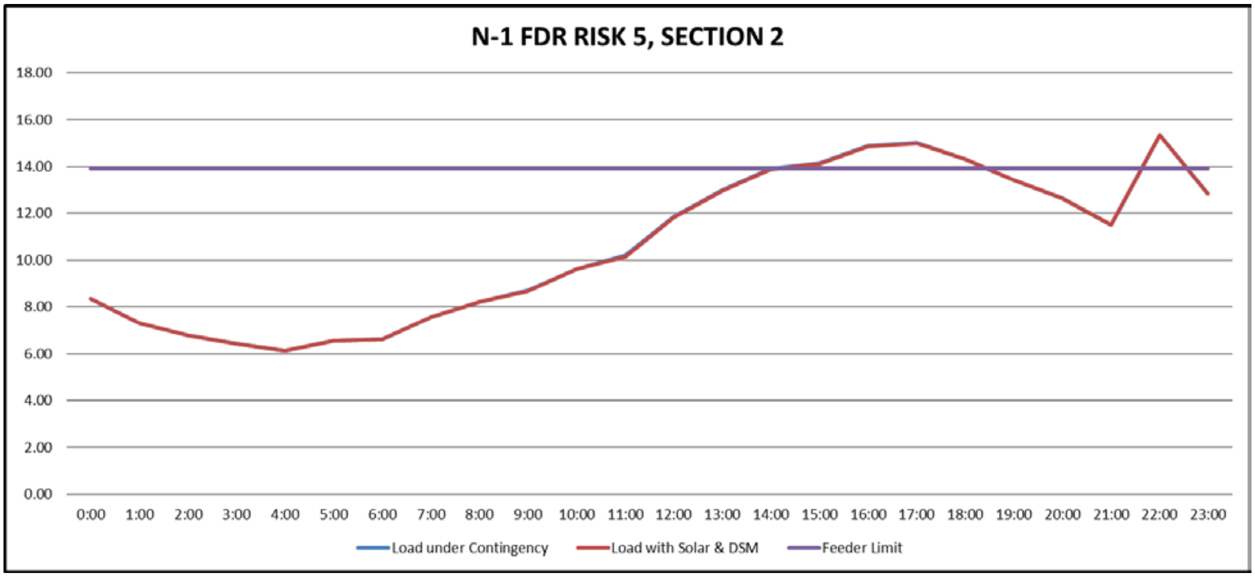
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 5, SECTION 2
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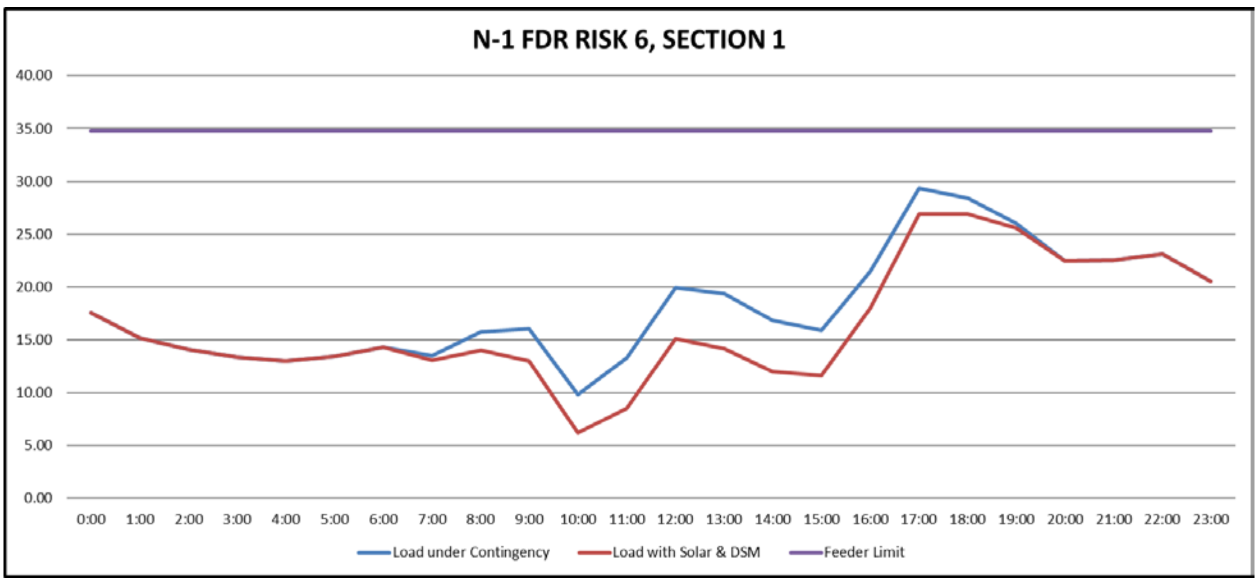
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 6, SECTION 1
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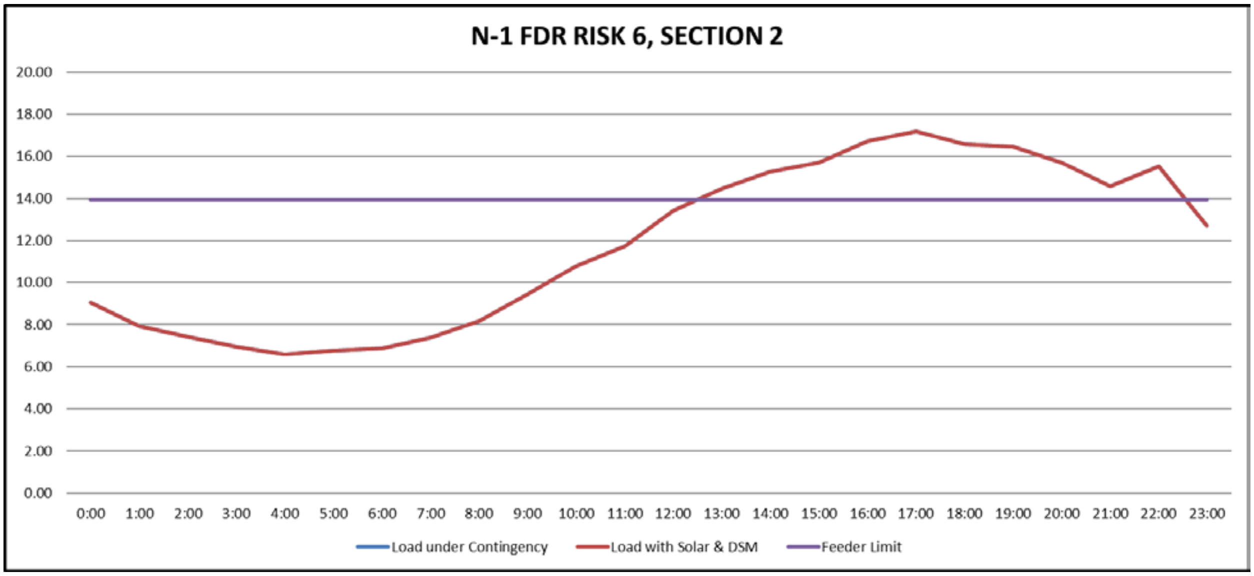
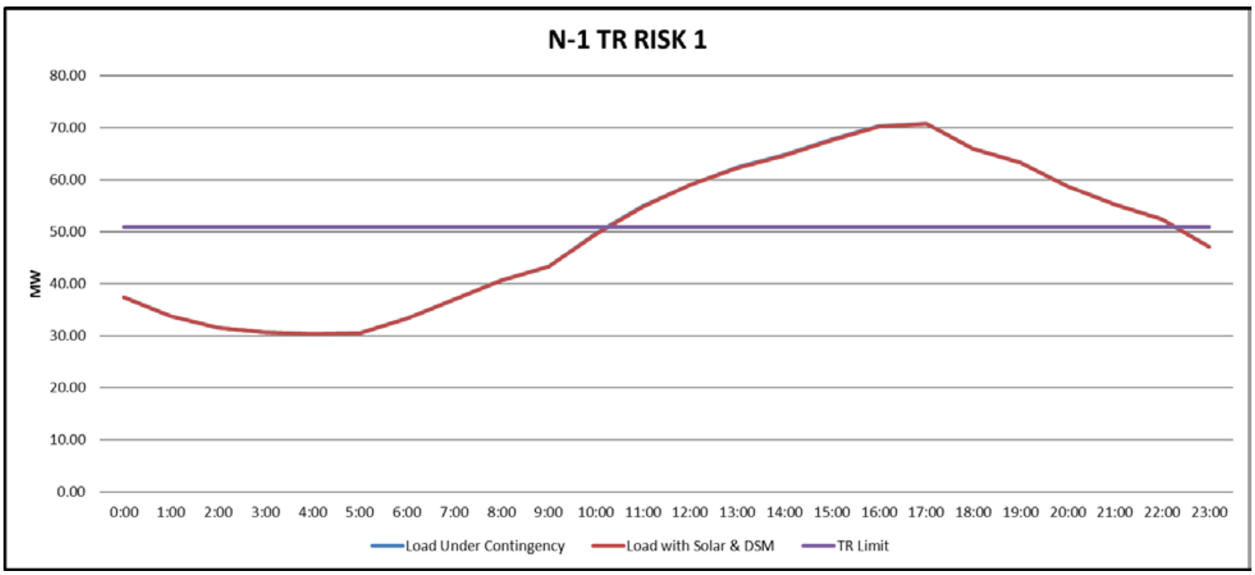
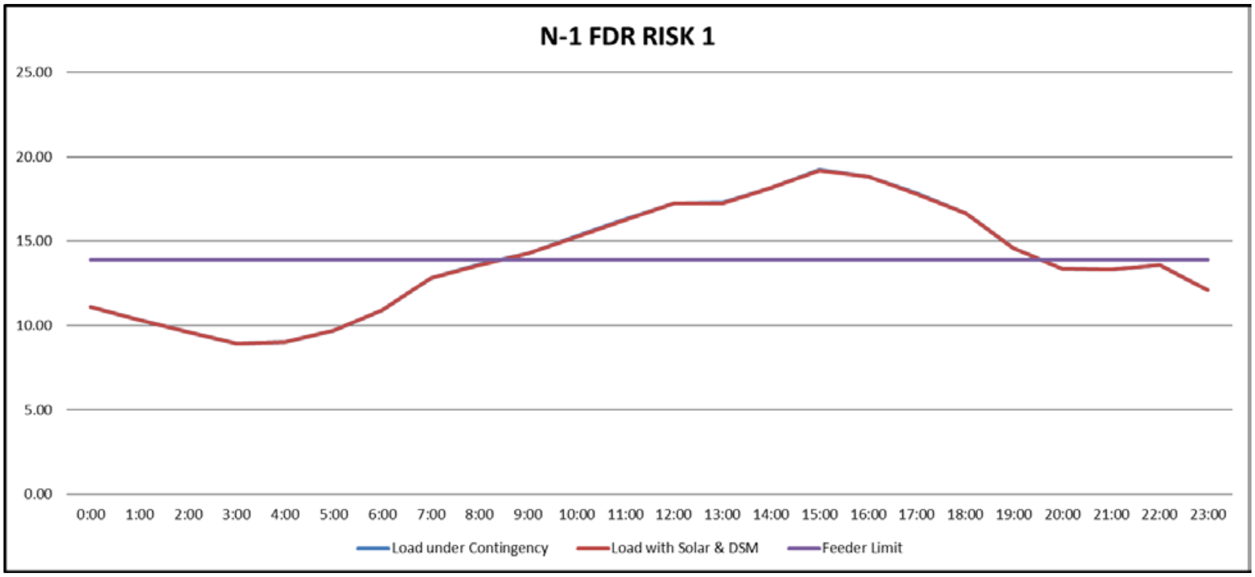
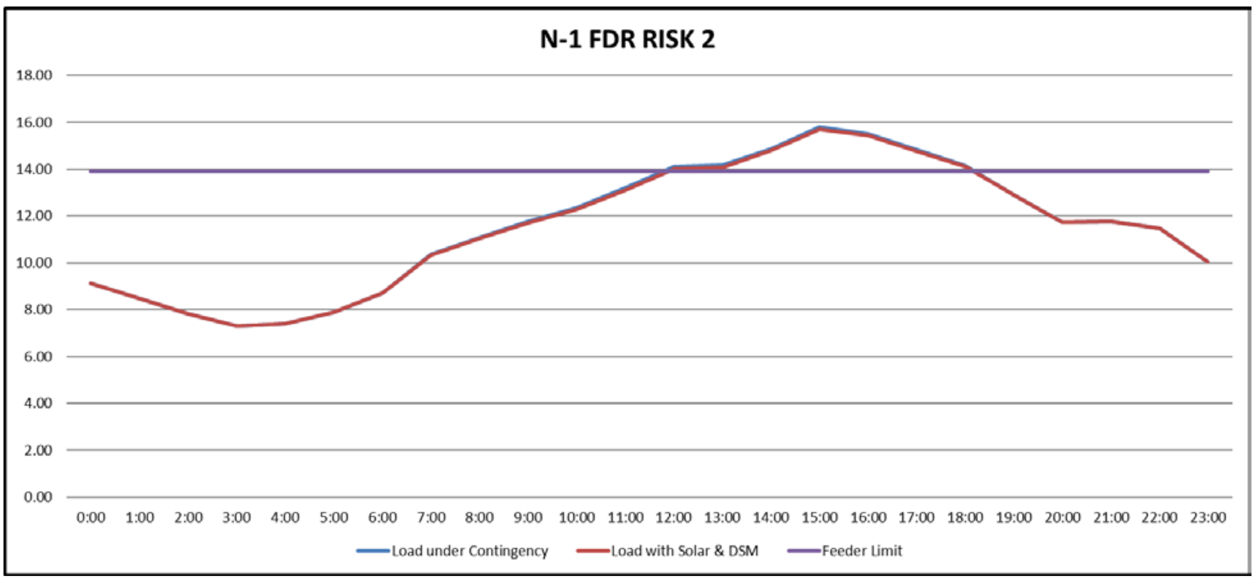
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

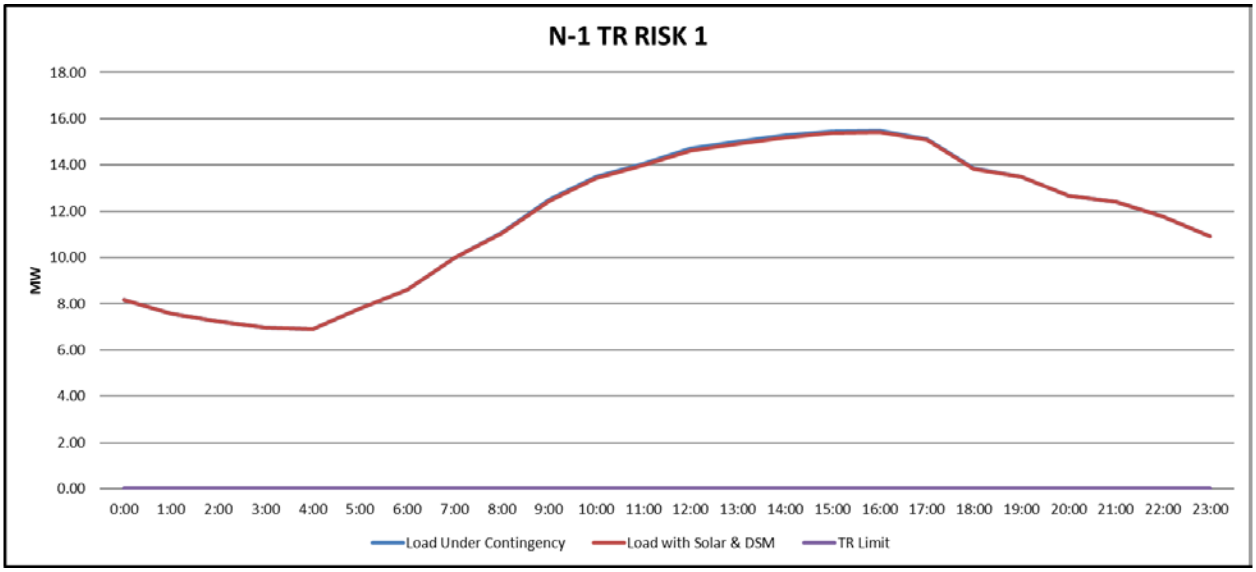

N-1 FDR RISK 6, SECTION 2
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 TR RISK 1
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
MW
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

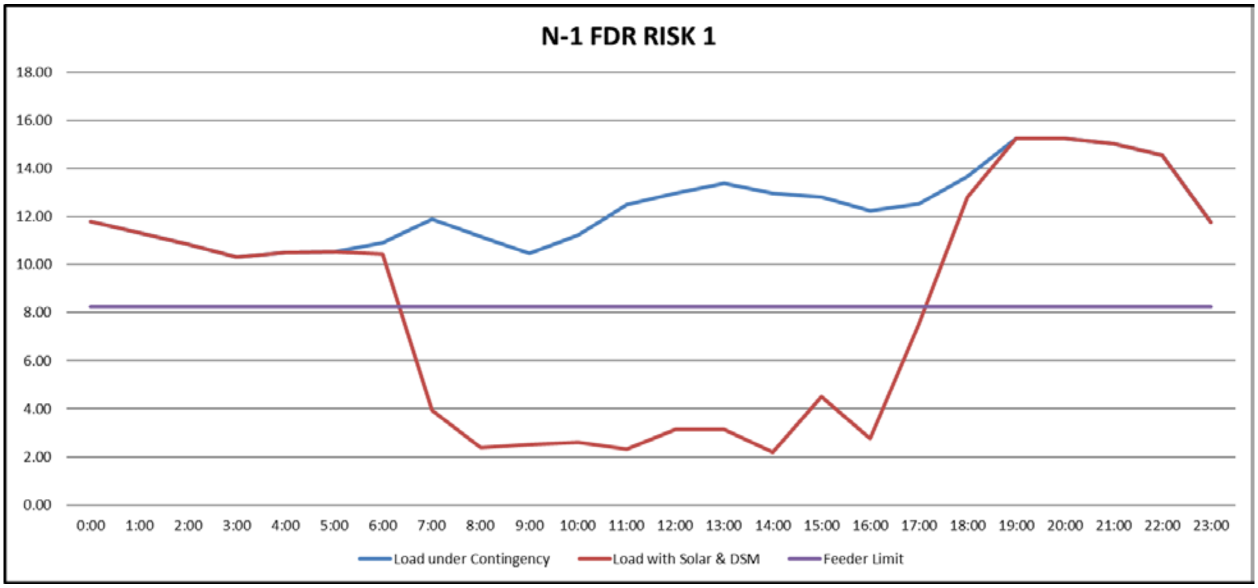
H. Install Orono ORO TR2 & Feeder

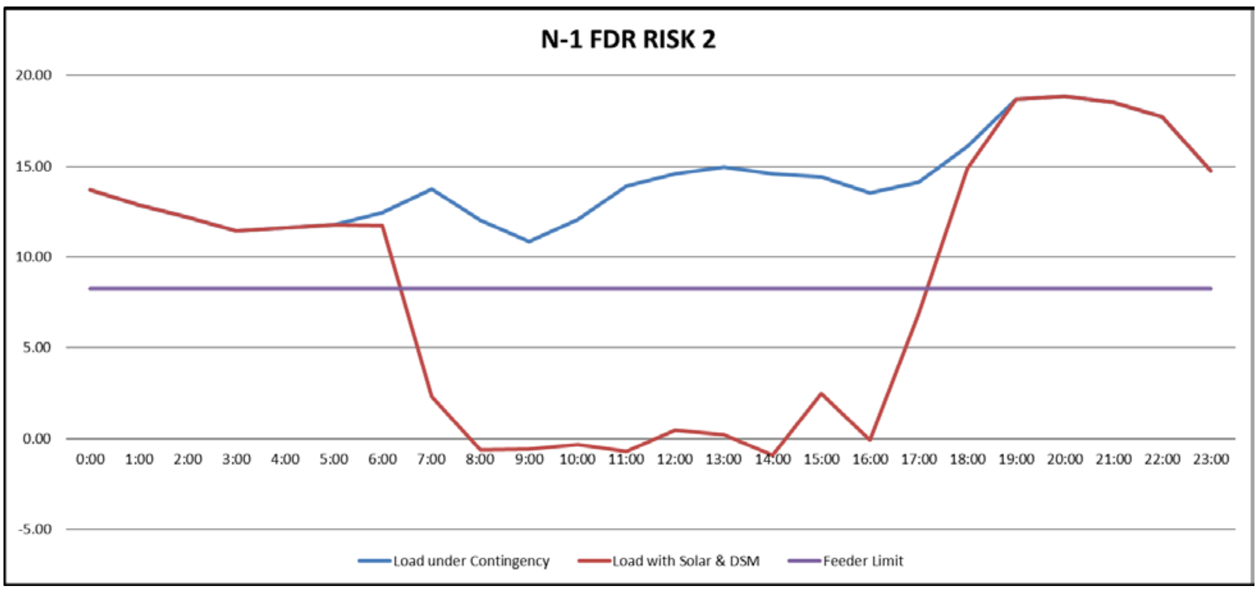


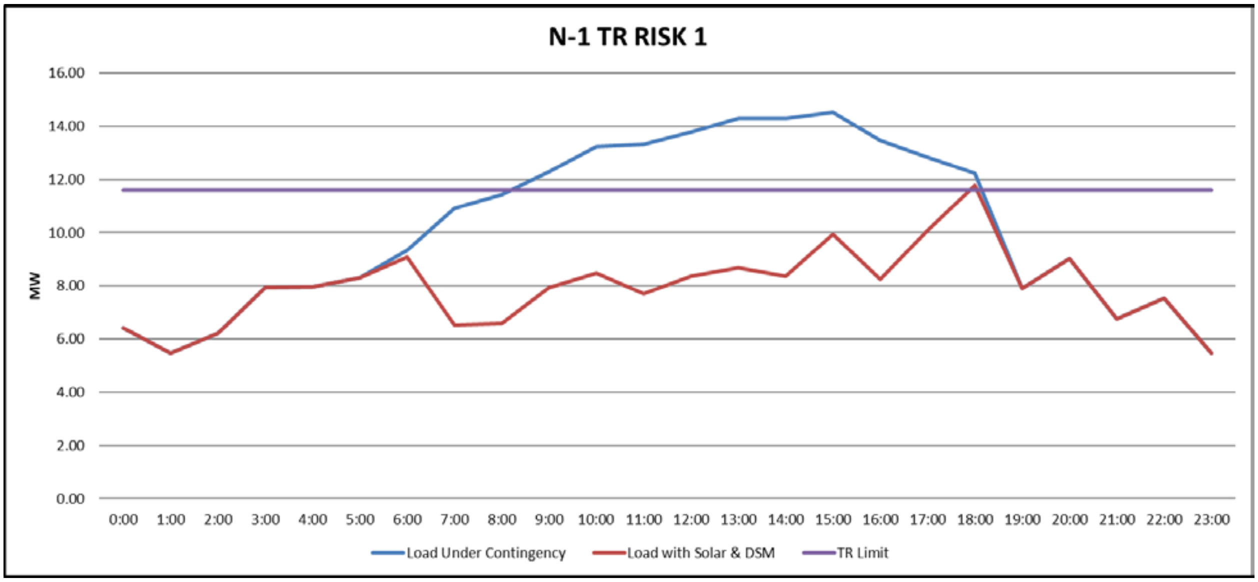



N-1 TR RISK 1
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
MW
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

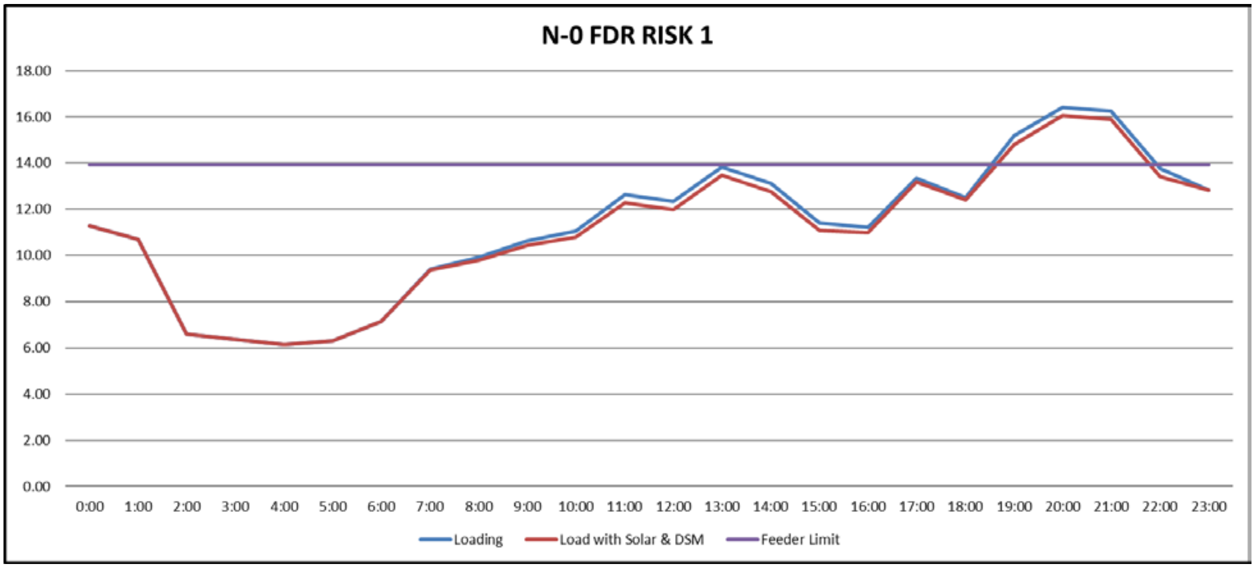
I. Reinforce Burnside BUR TR2

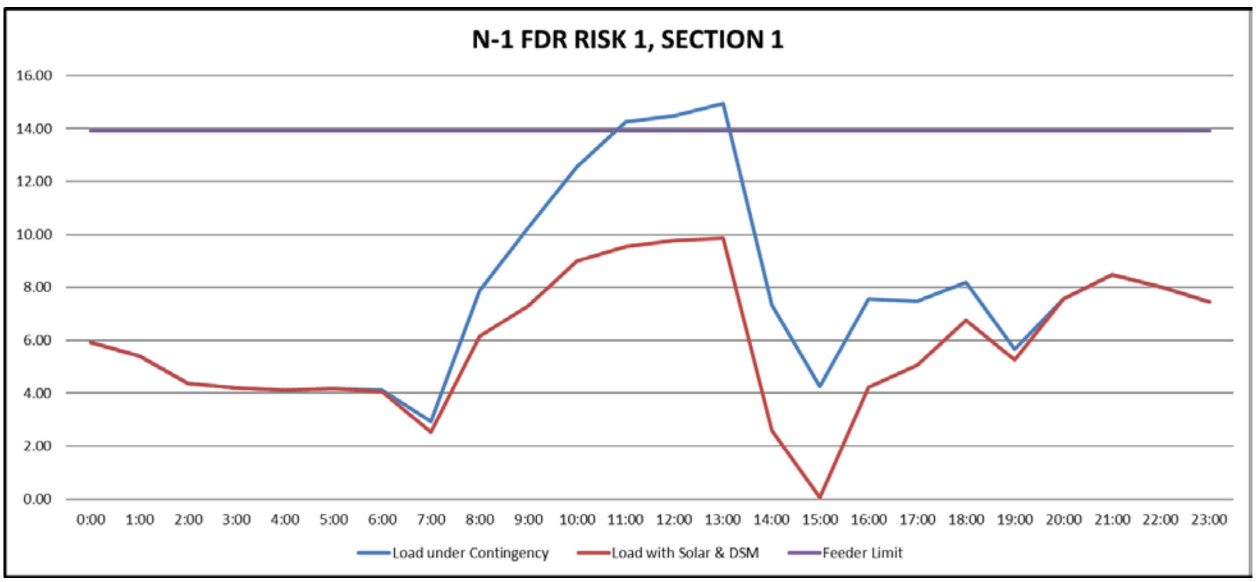


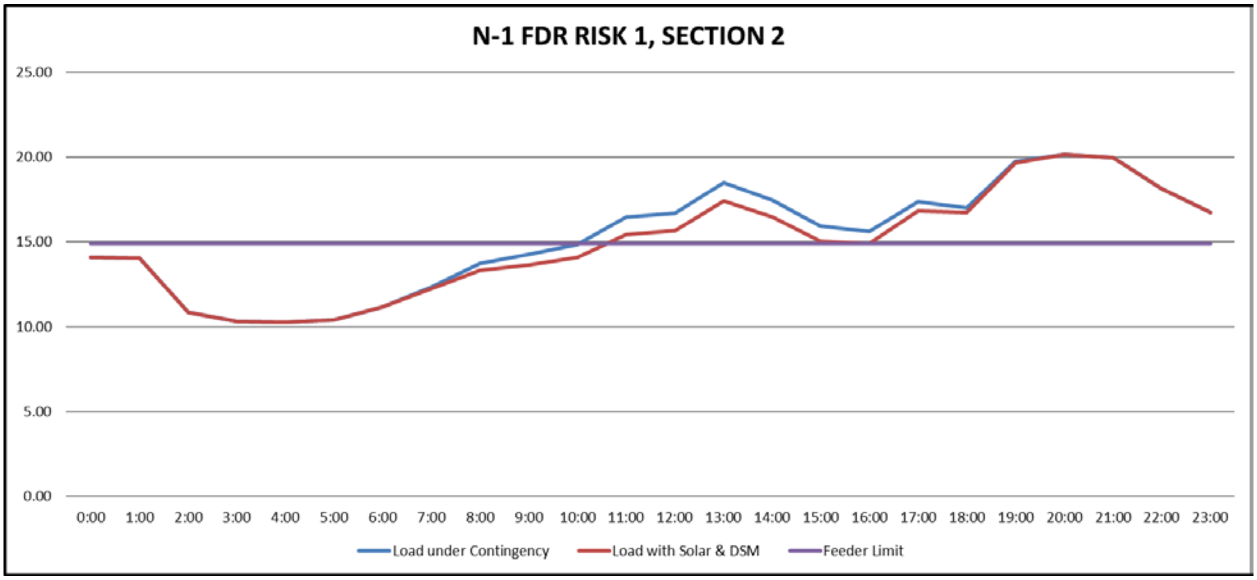


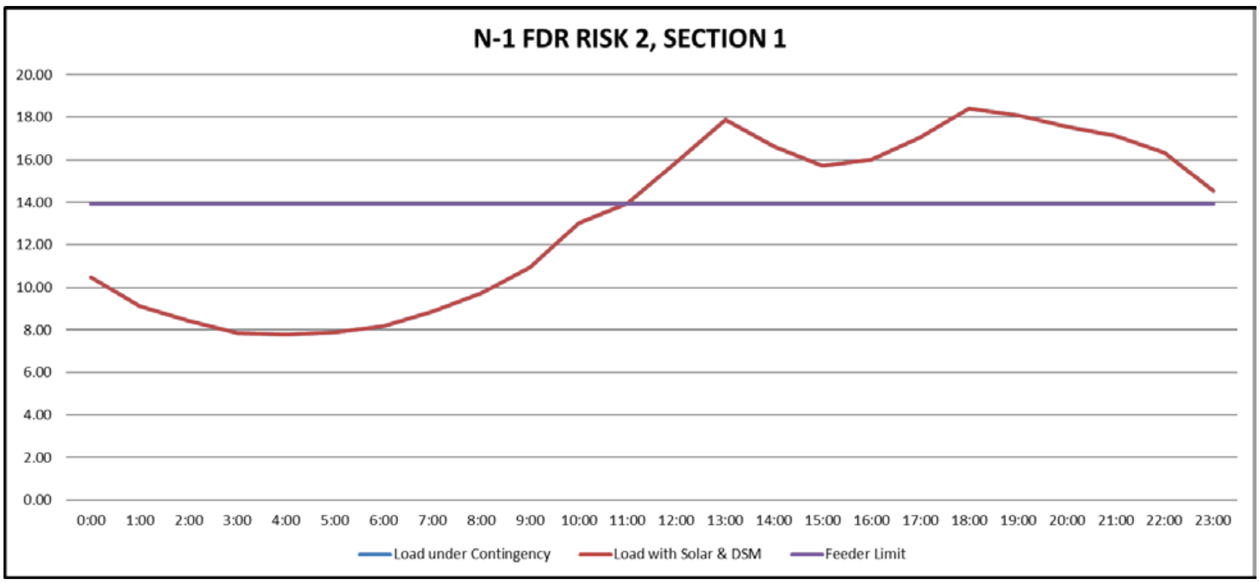

N-1 TR RISK 1
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
MW
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

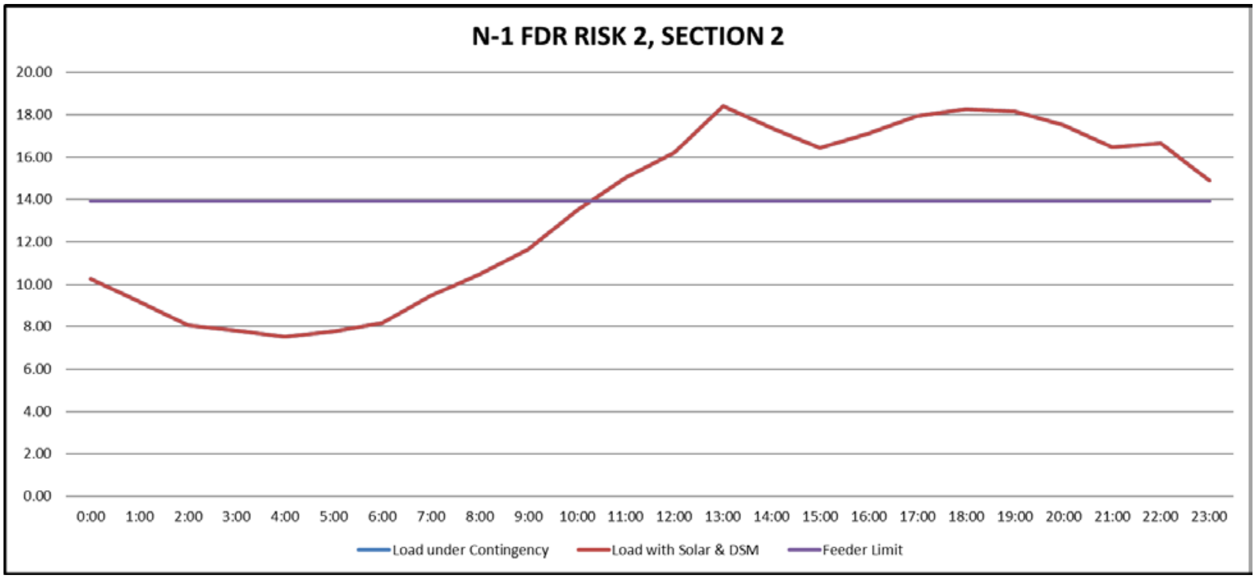
J. Install Cottage Grove CGR TR03

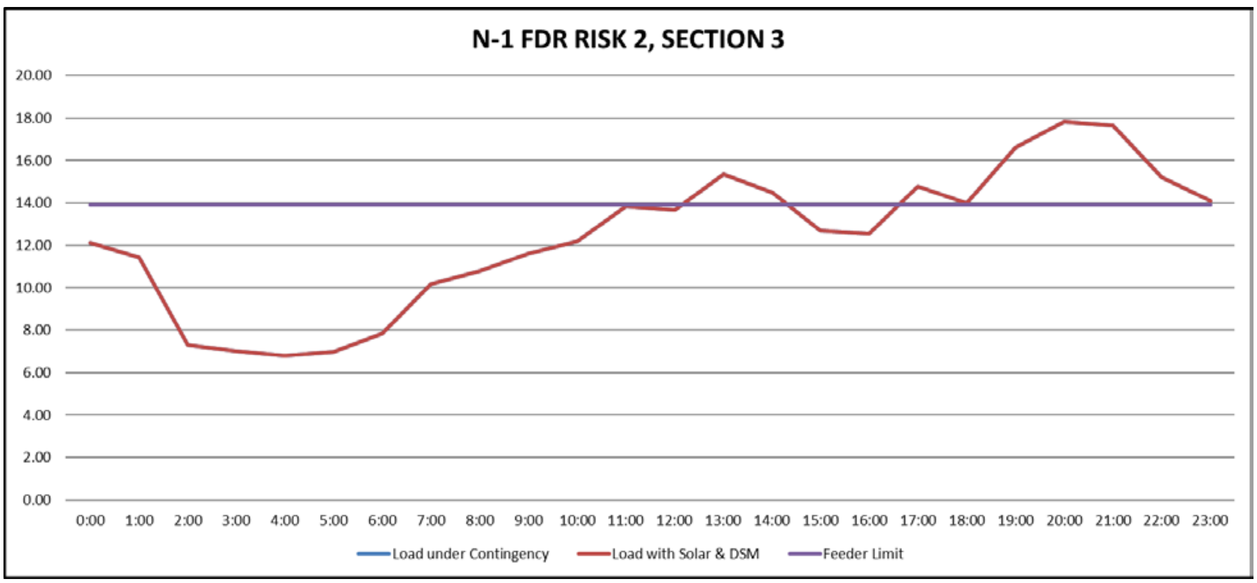


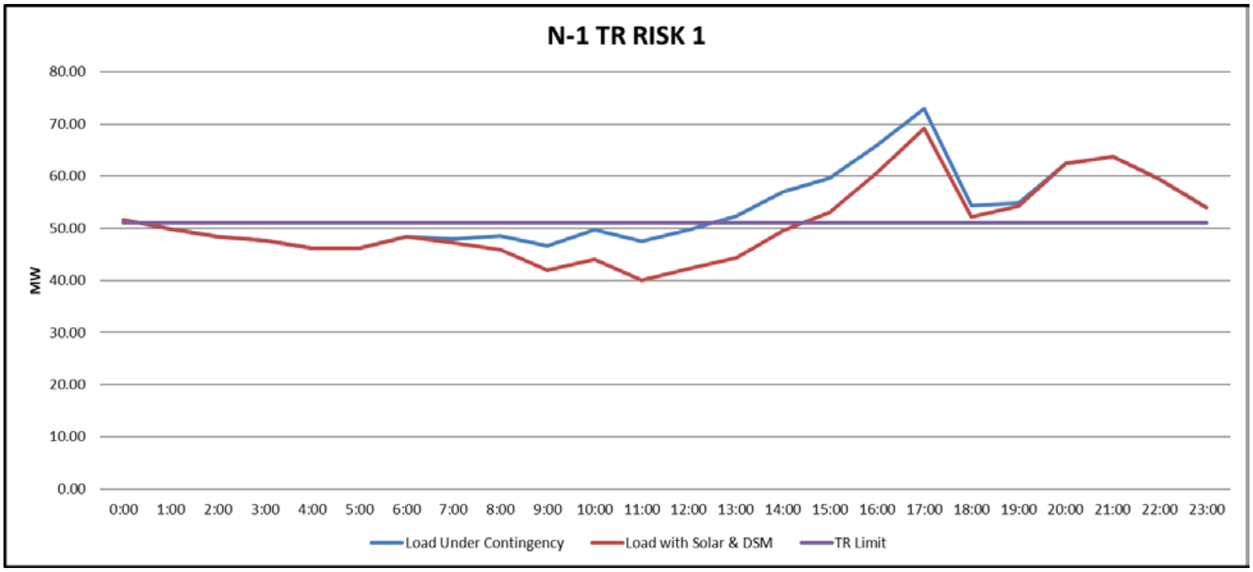


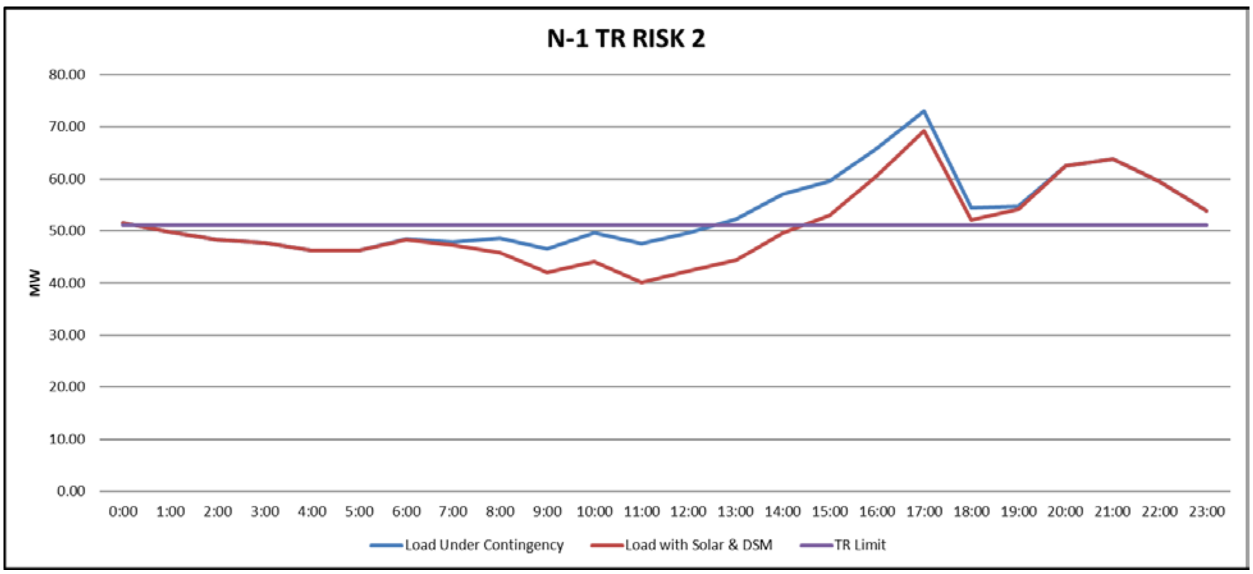

N-1 FDR RISK 1, SECTION 2
25.00
20.00
15.00
10.00
5.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit


N-1 FDR RISK 2, SECTION 1
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

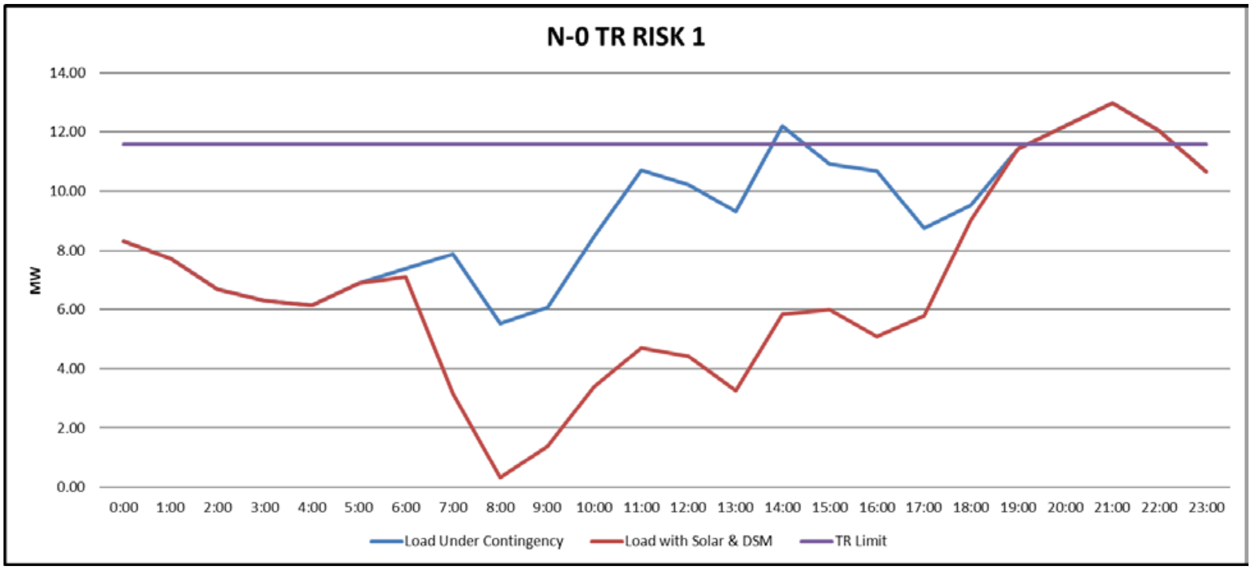

N-1 FDR RISK 2, SECTION 2
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

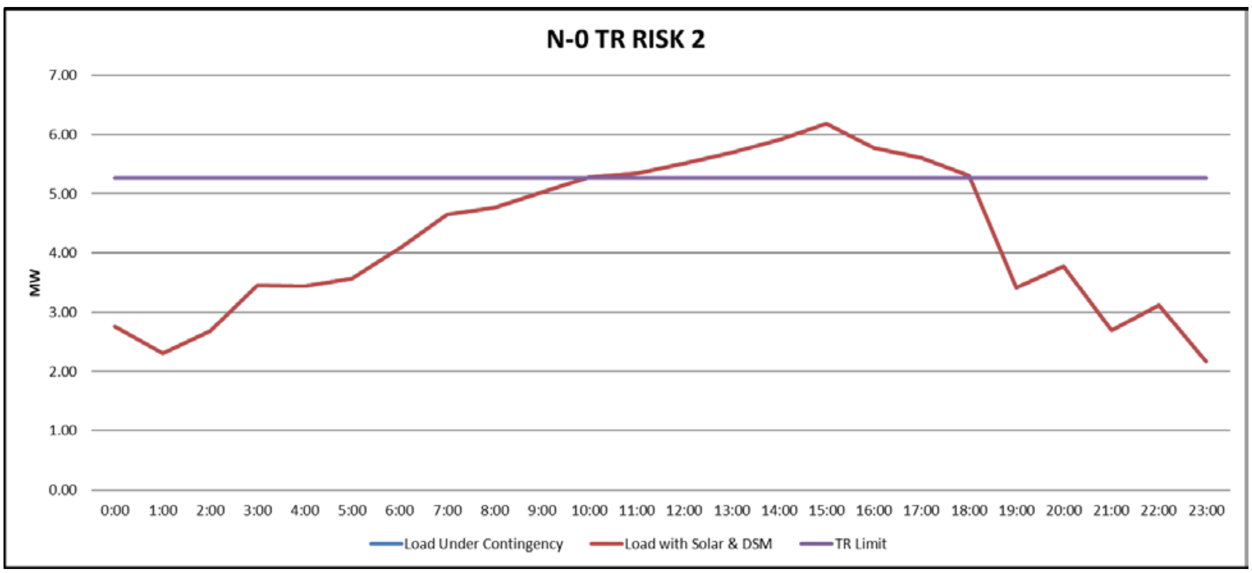

N-1 FDR RISK 2, SECTION 3
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load under Contingency
Load with Solar & DSM
Feeder Limit

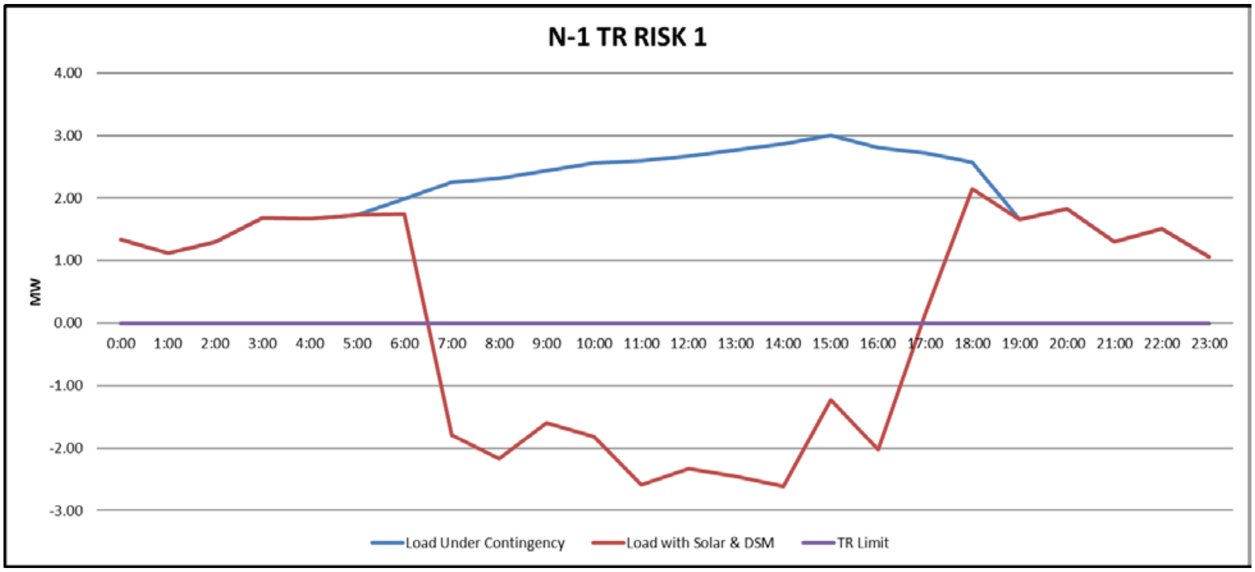

N-1 TR RISK 1
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
MW
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

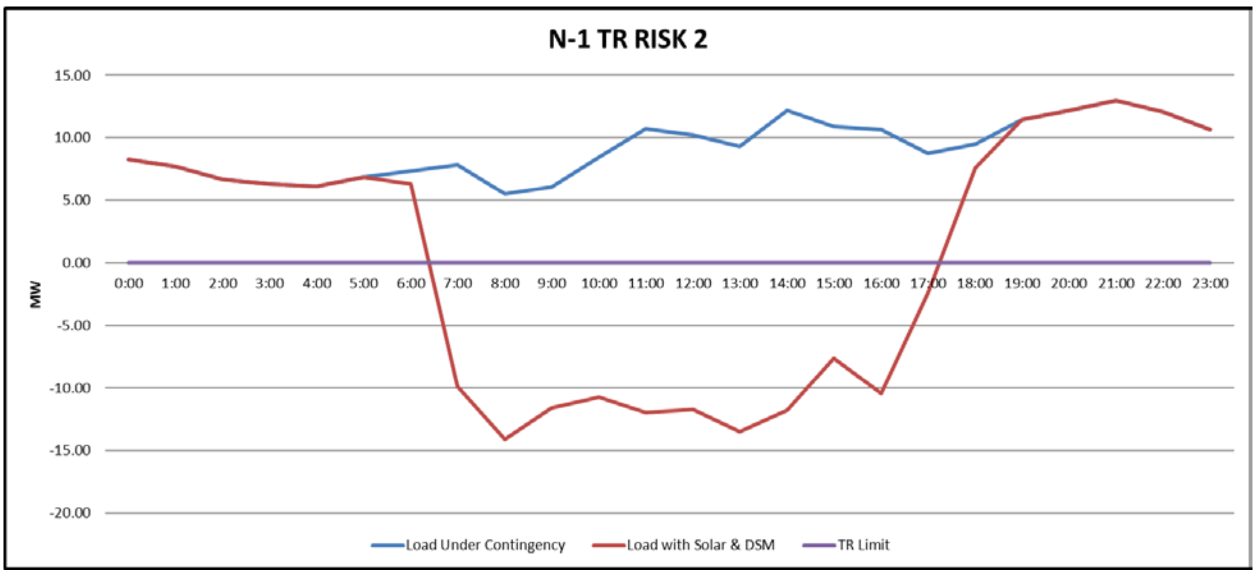

N-1 TR RISK 2
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
MW
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load with Solar & DSM
TR Limit

K. Install Cannon Falls Trans CTF TR2 & Fdr






N-1 TR RISK 1
4.00
3.00
2.00
1.00
0.00
-1.00
-2.00
-3.00
MW
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load with Solar & DSM
TR Limit


N-1 TR RISK 2
15.00
10.00
5.00
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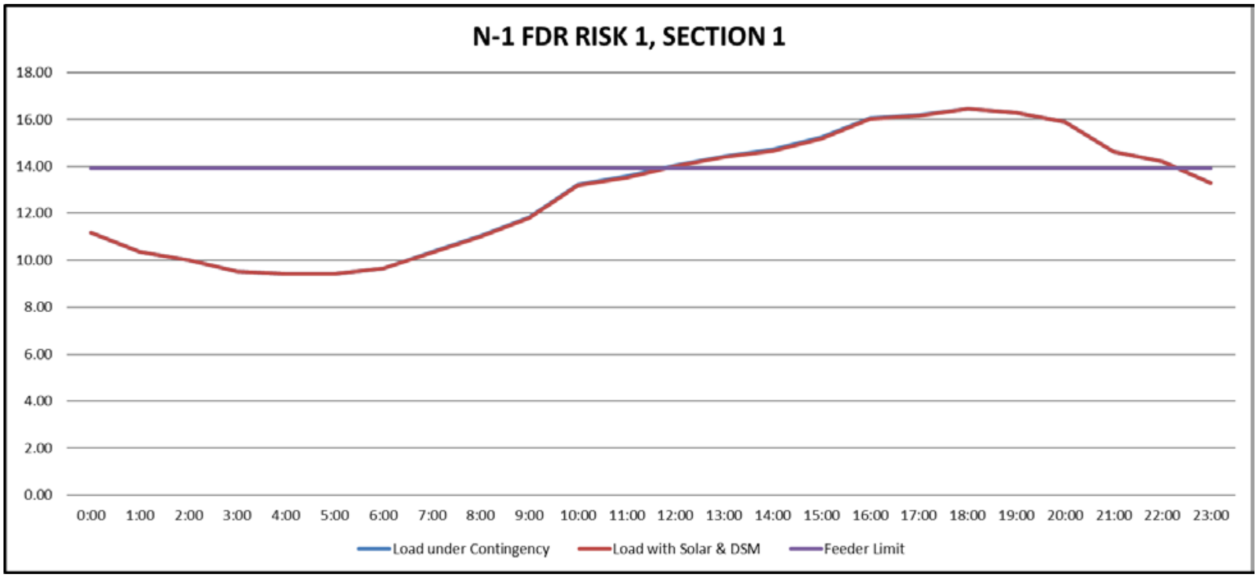
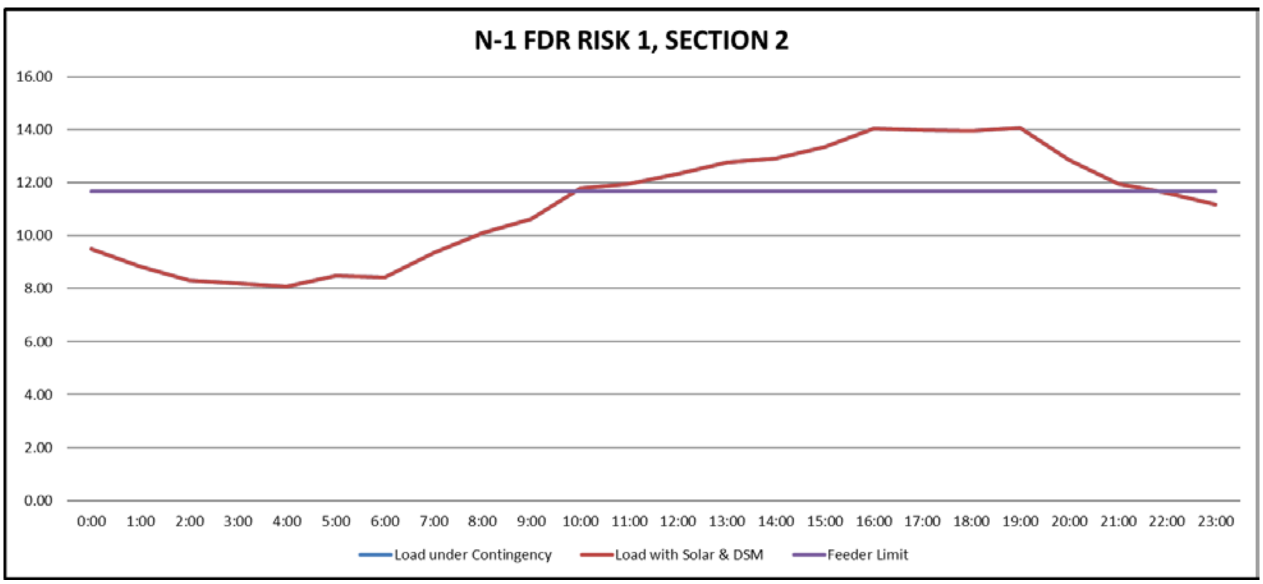
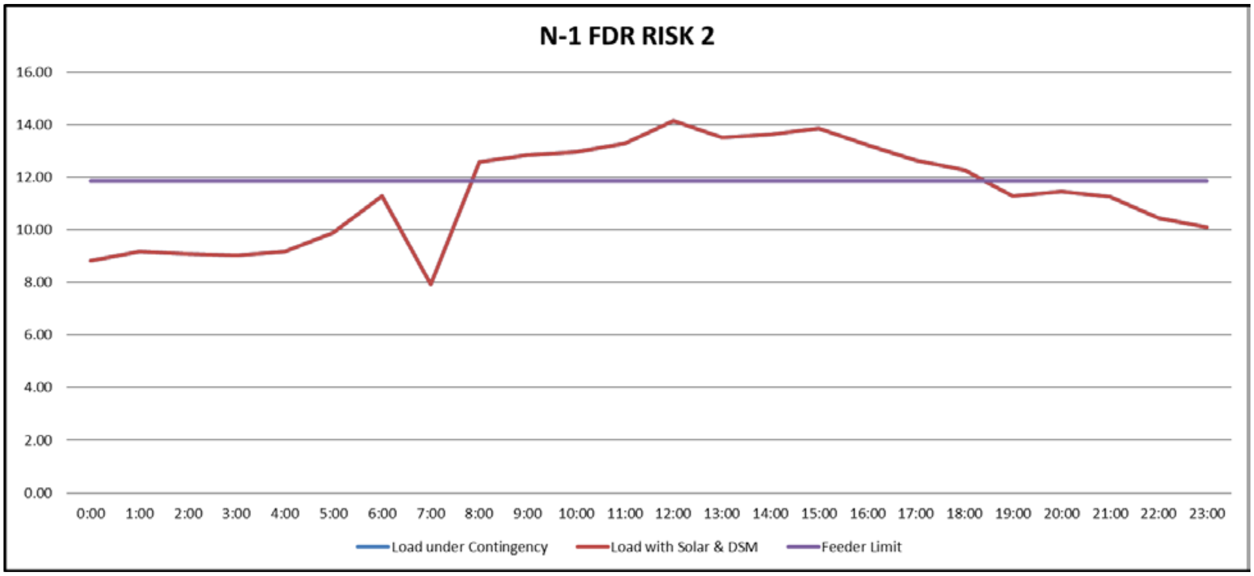
Load Under Contingency
Load with Solar & DSM
TR Limit

L. Install Western WES TR3 & Feeders



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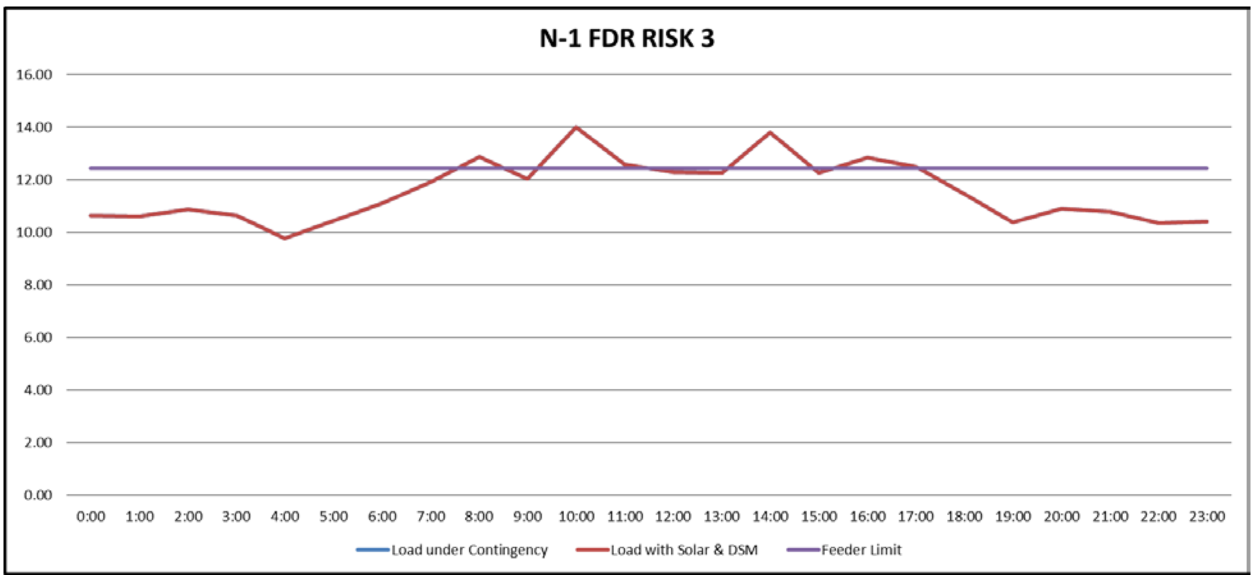
Load under Contingency
Load with Solar & DSM
Feeder Limit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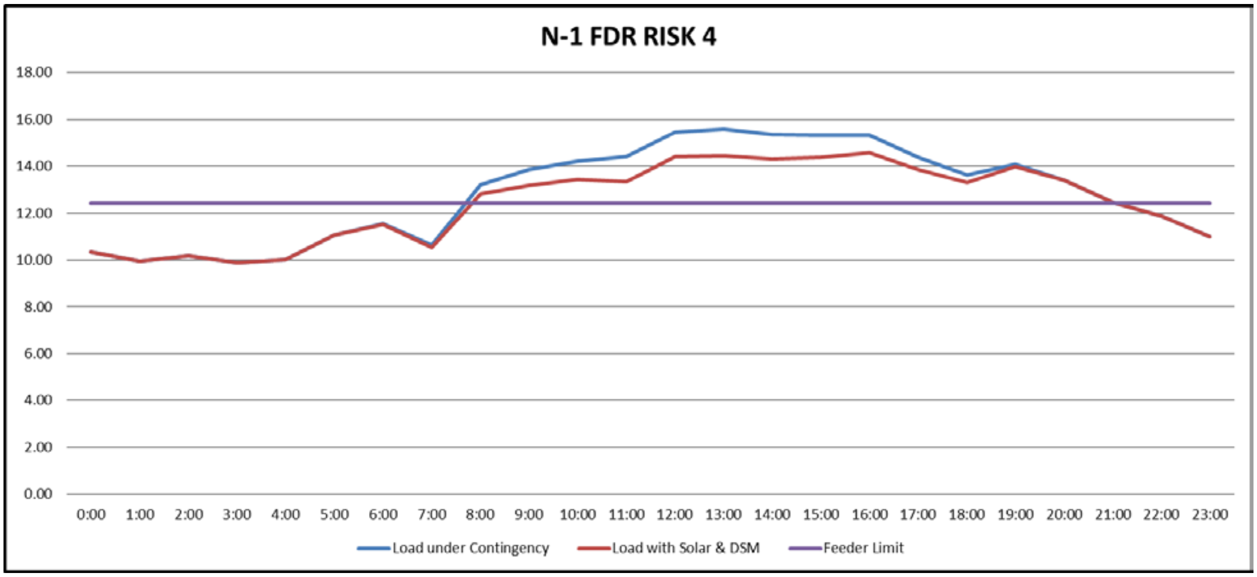
Load under Contingency
Load with Solar & DSM
Feeder Limit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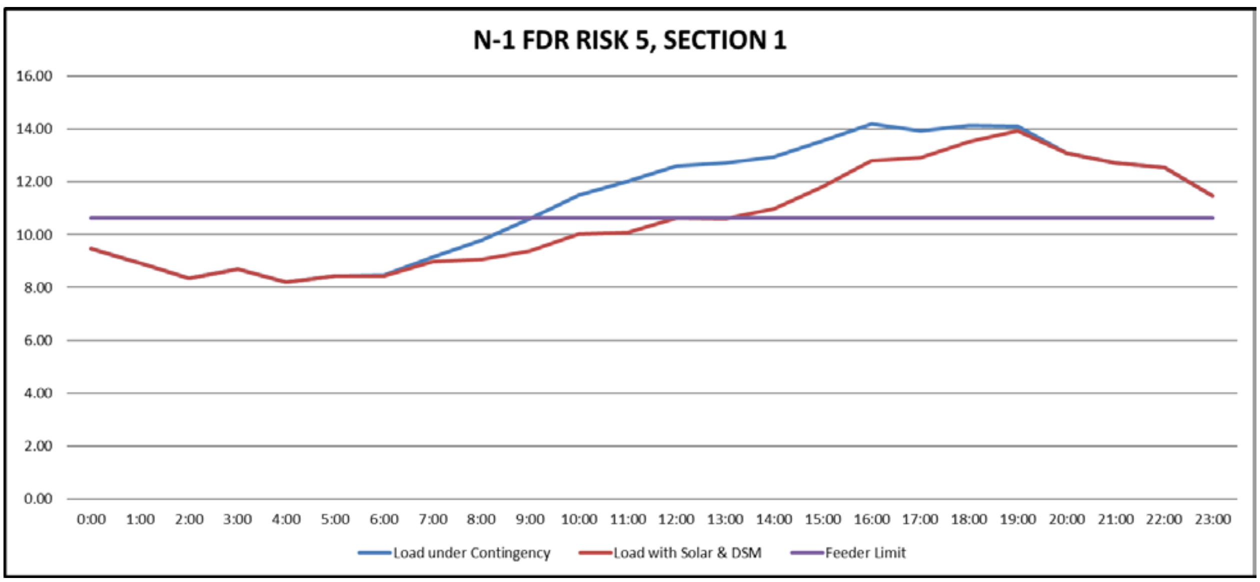
Load under Contingency
Load with Solar & DSM
Feeder Limit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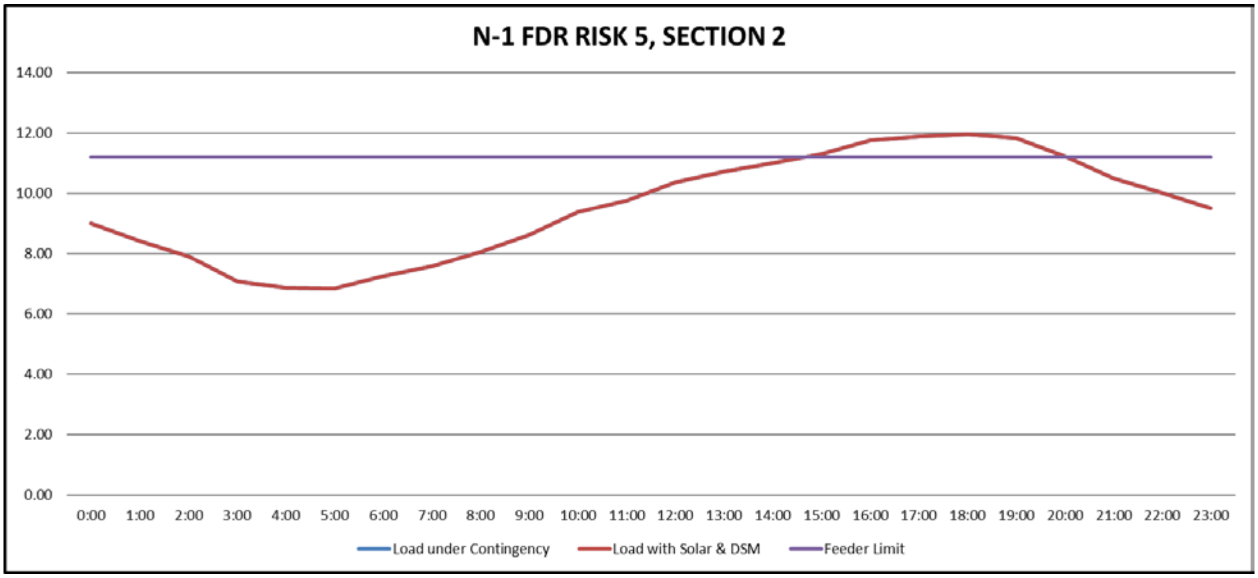
Load under Contingency
Load with Solar & DSM
Feeder Limit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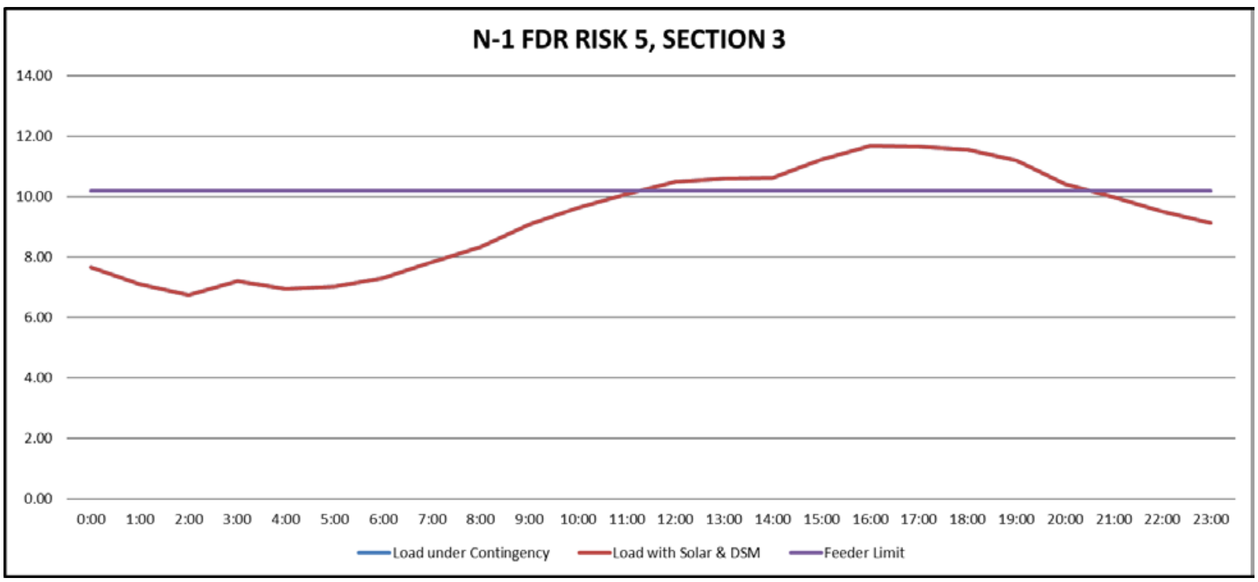
Load under Contingency
Load with Solar & DSM
Feeder Limit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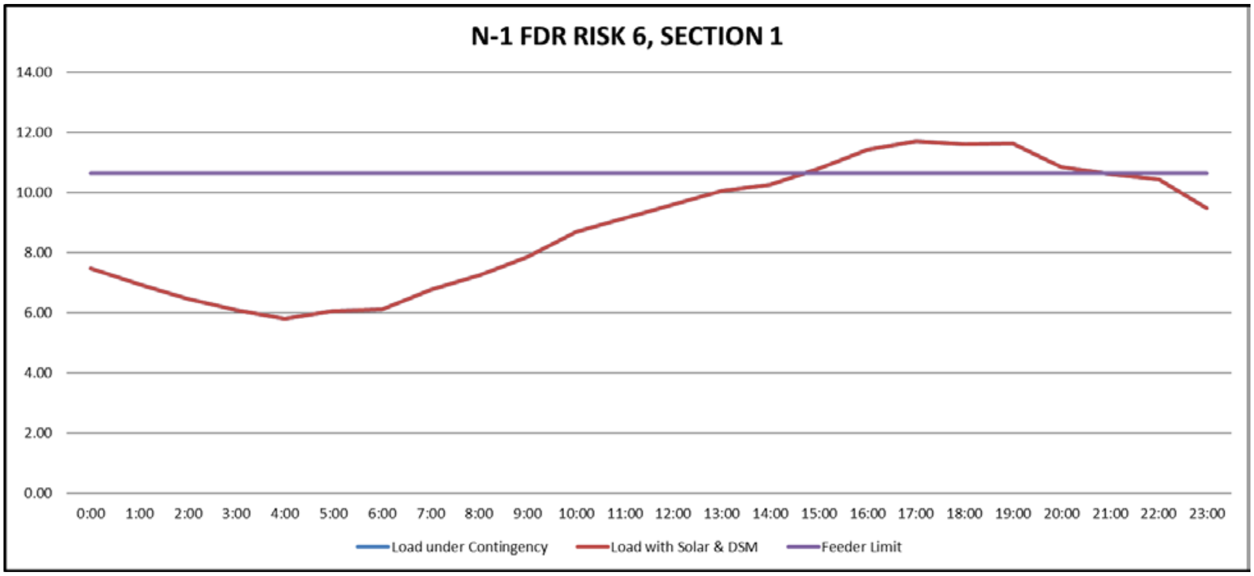
Load under Contingency
Load with Solar & DSM
Feeder Limit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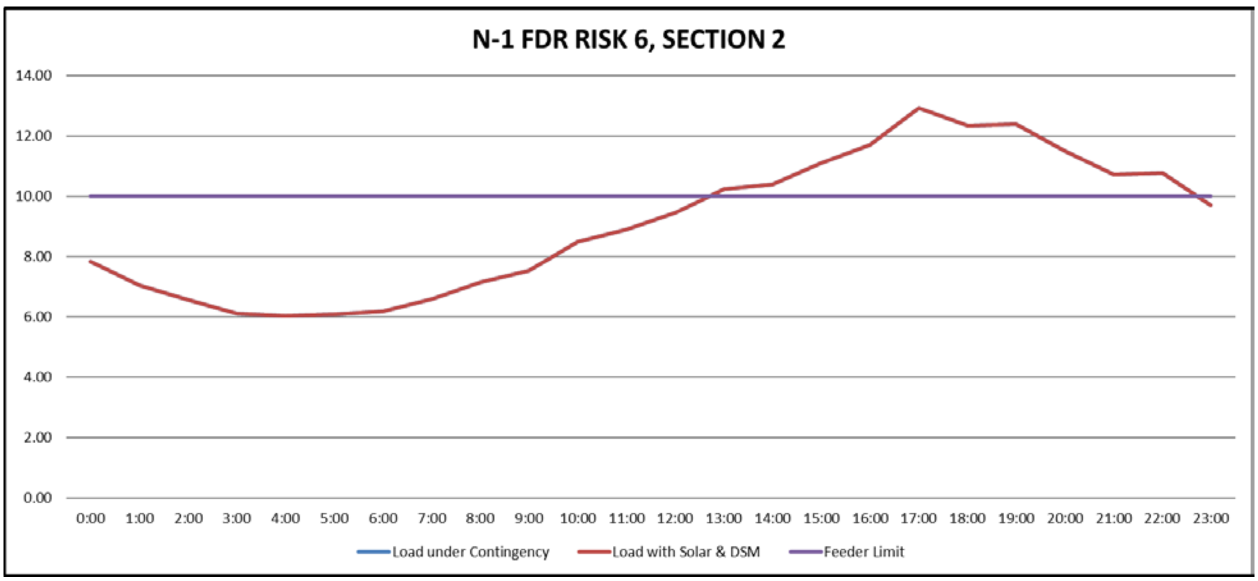
Load under Contingency
Load with Solar & DSM
Feeder Limit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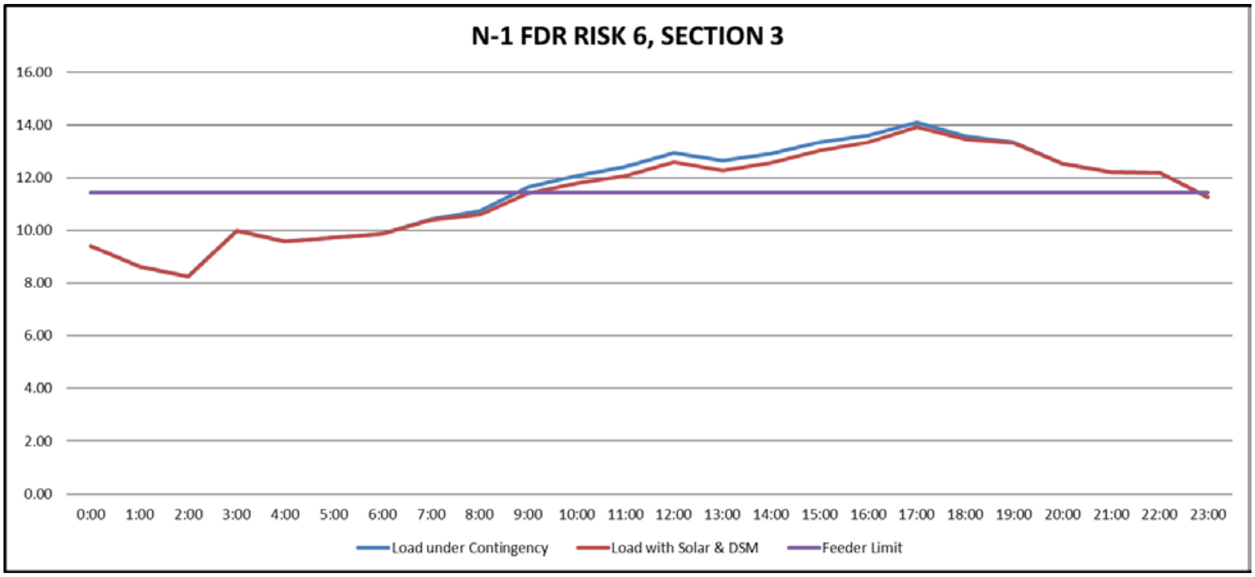
Load under Contingency
Load with Solar & DSM
Feeder Limit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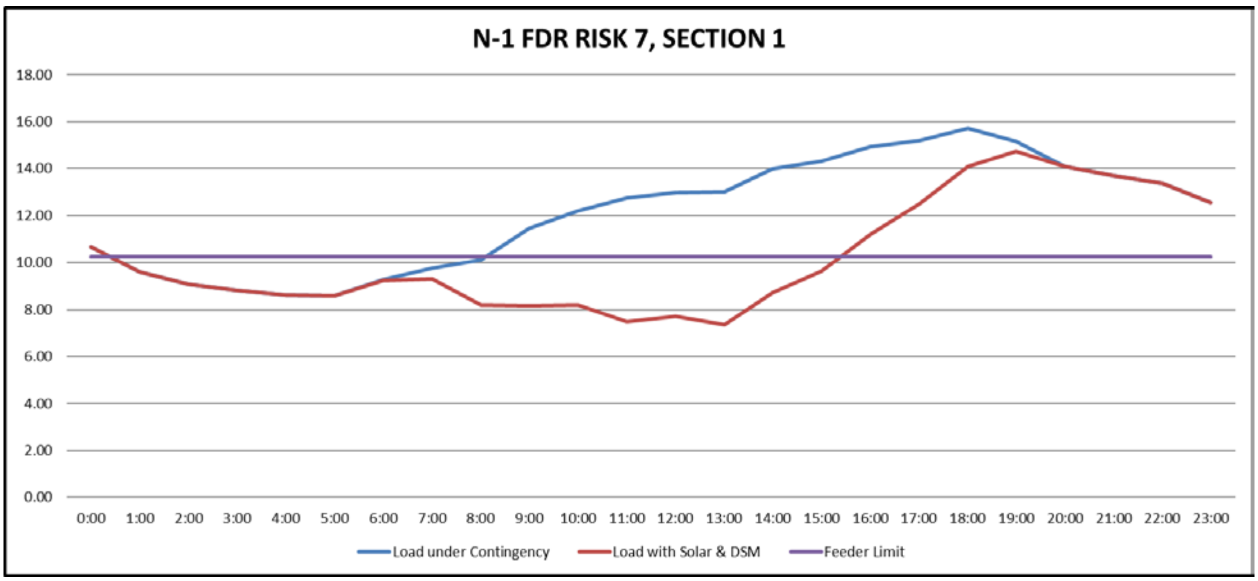
Load under Contingency
Load with Solar & DSM
Feeder Limit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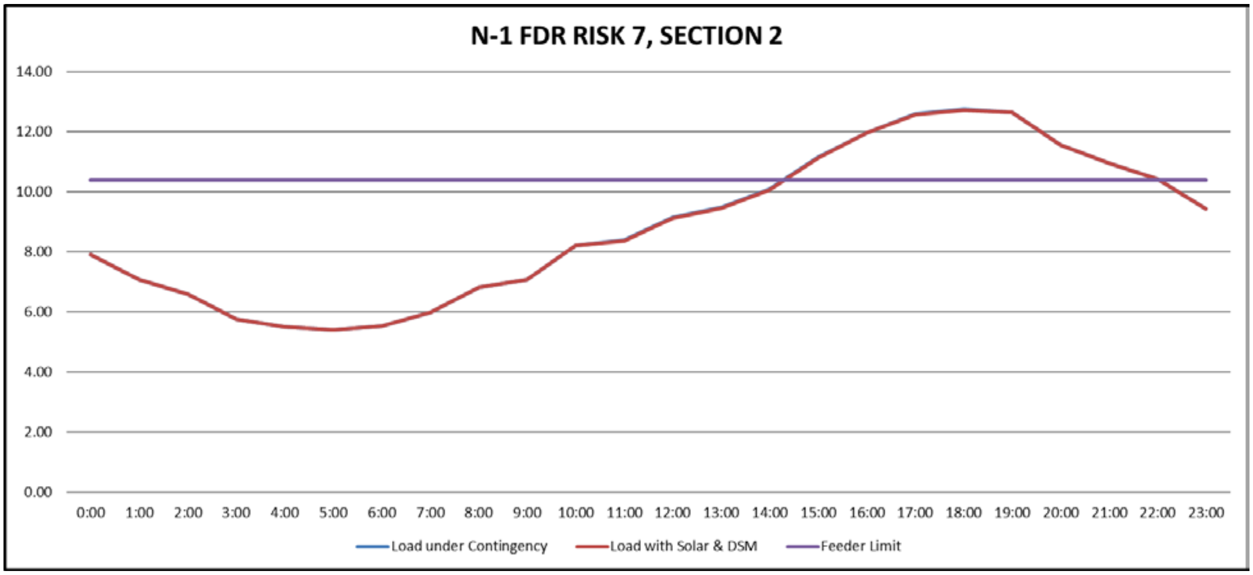
Load under Contingency
Load with Solar & DSM
Feeder Limit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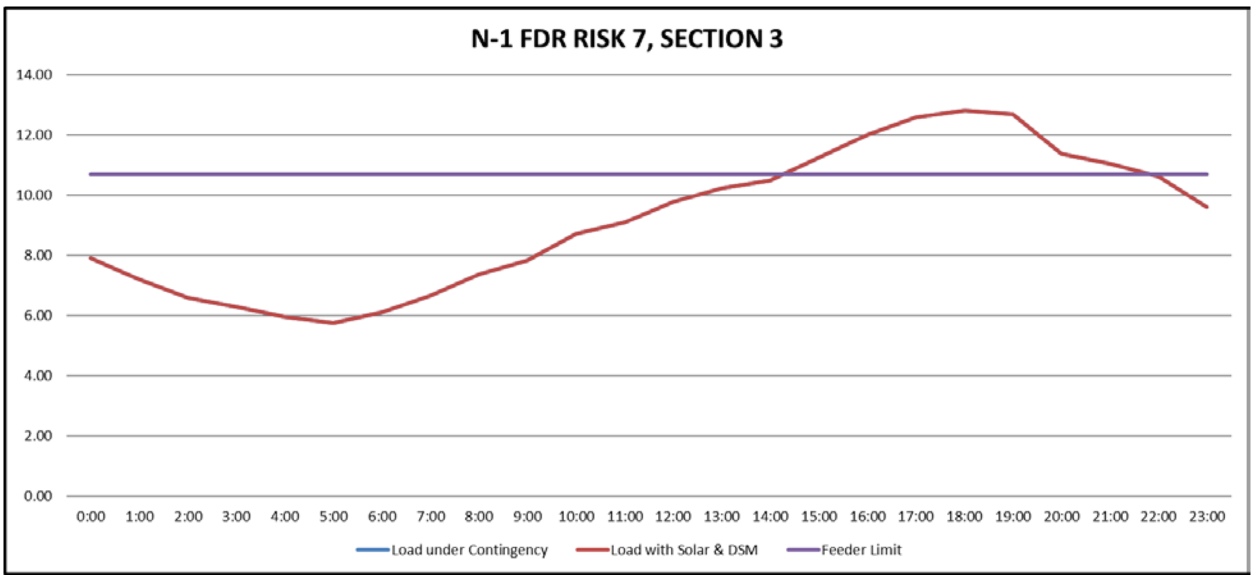
Load under Contingency
Load with Solar & DSM
Feeder Limit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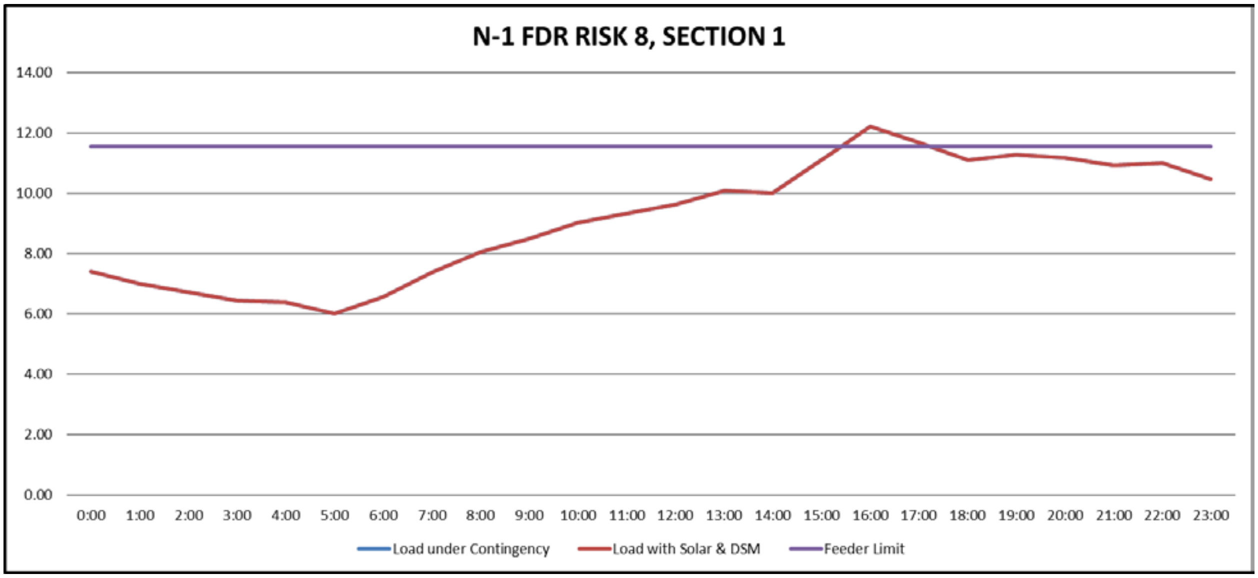
Load under Contingency
Load with Solar & DSM
Feeder Limit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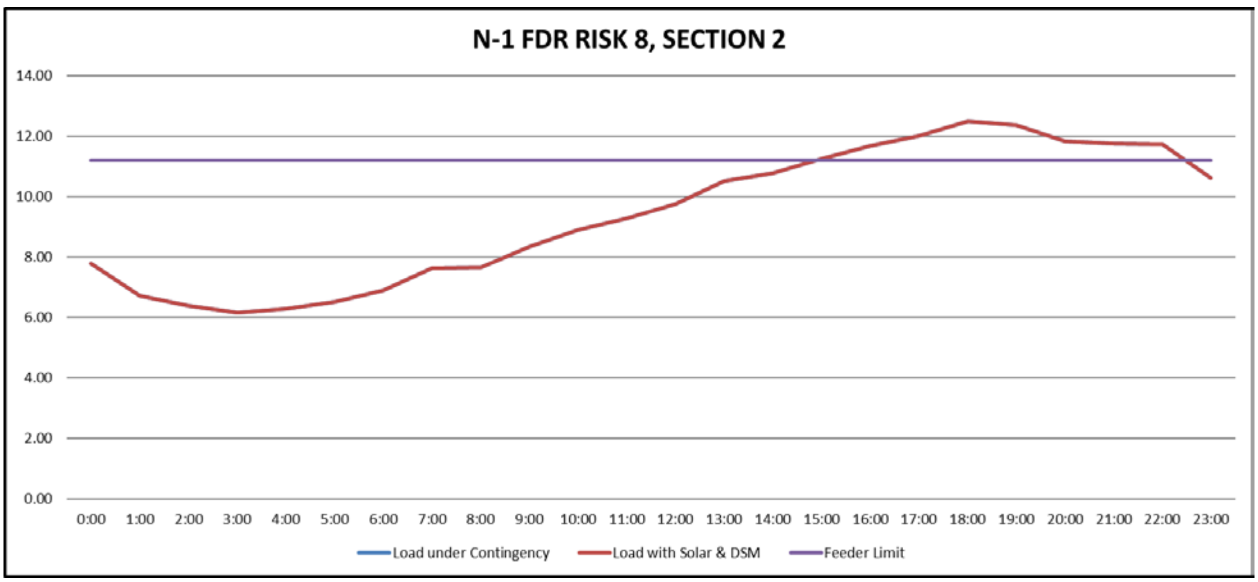
Load under Contingency
Load with Solar & DSM
Feeder Limit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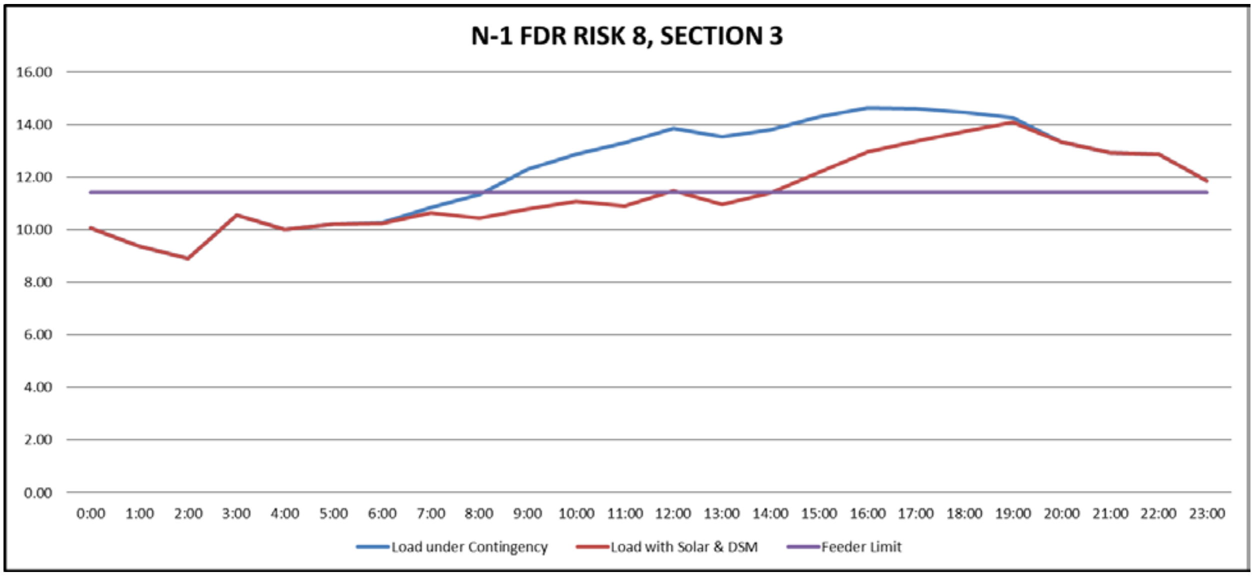
Load under Contingency
Load with Solar & DSM
Feeder Limit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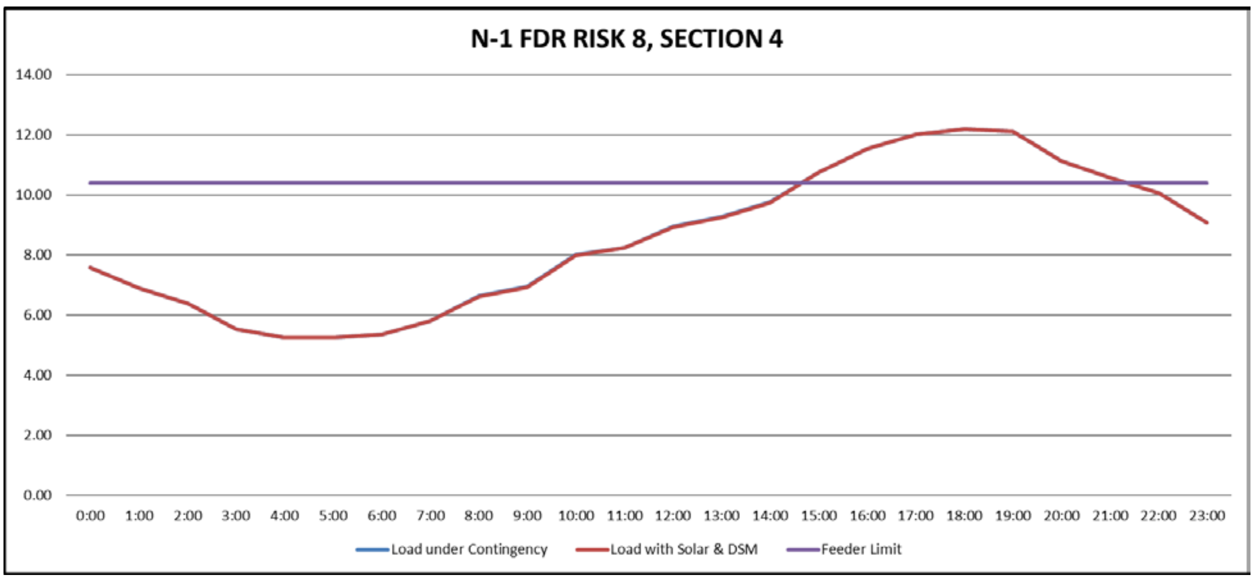
Load under Contingency
Load with Solar & DSM
Feeder Limit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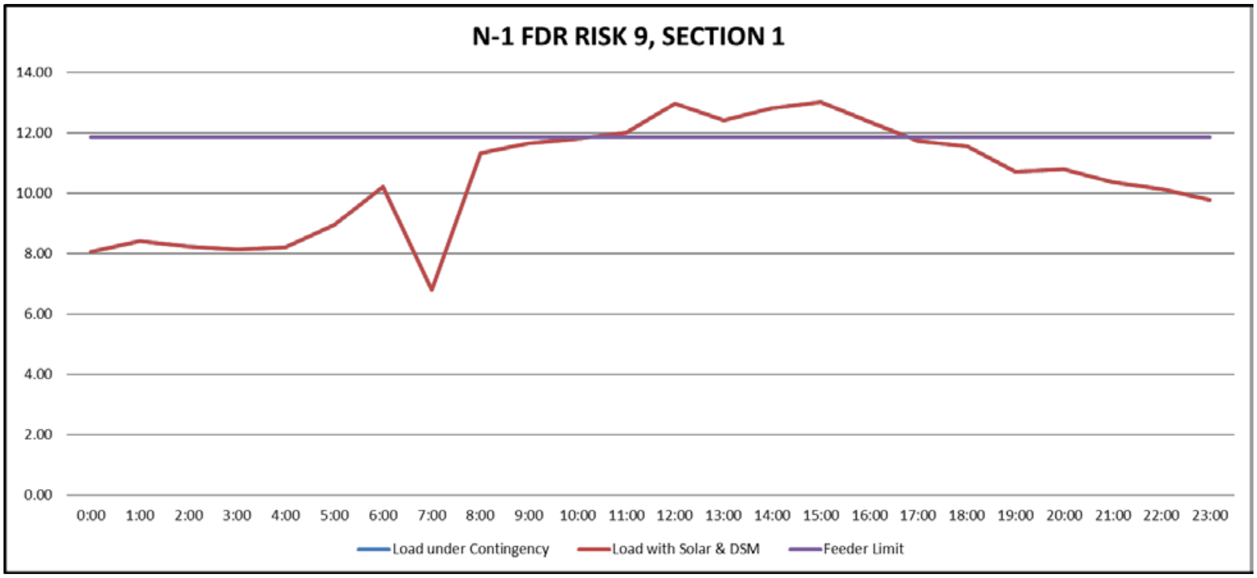
Load under Contingency
Load with Solar & DSM
Feeder Limit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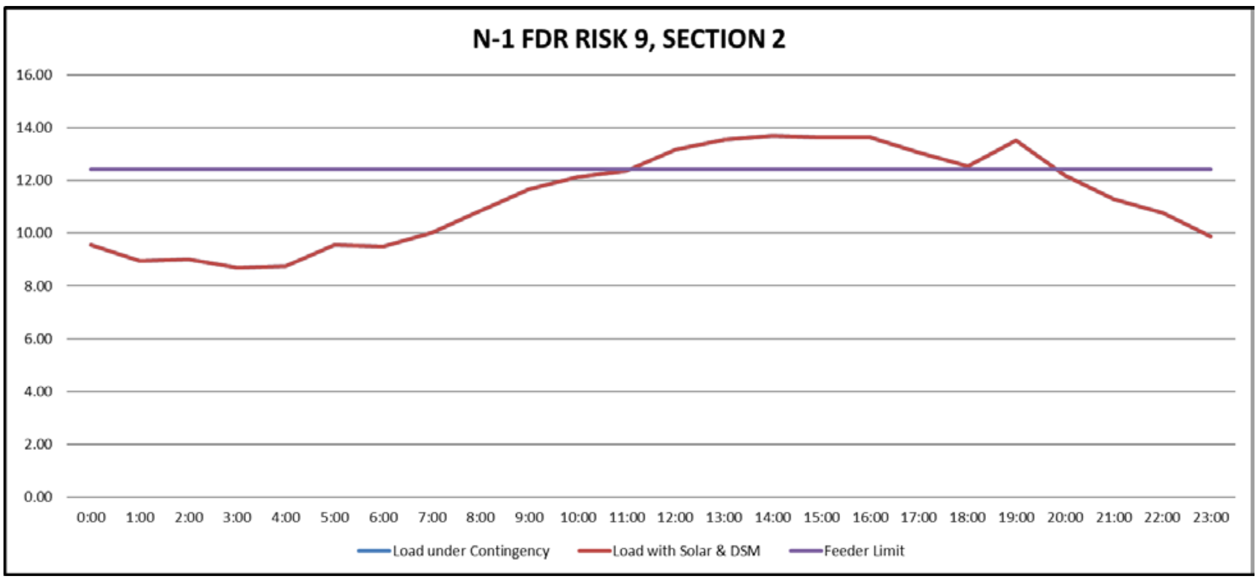
Load under Contingency
Load with Solar & DSM
Feeder Limit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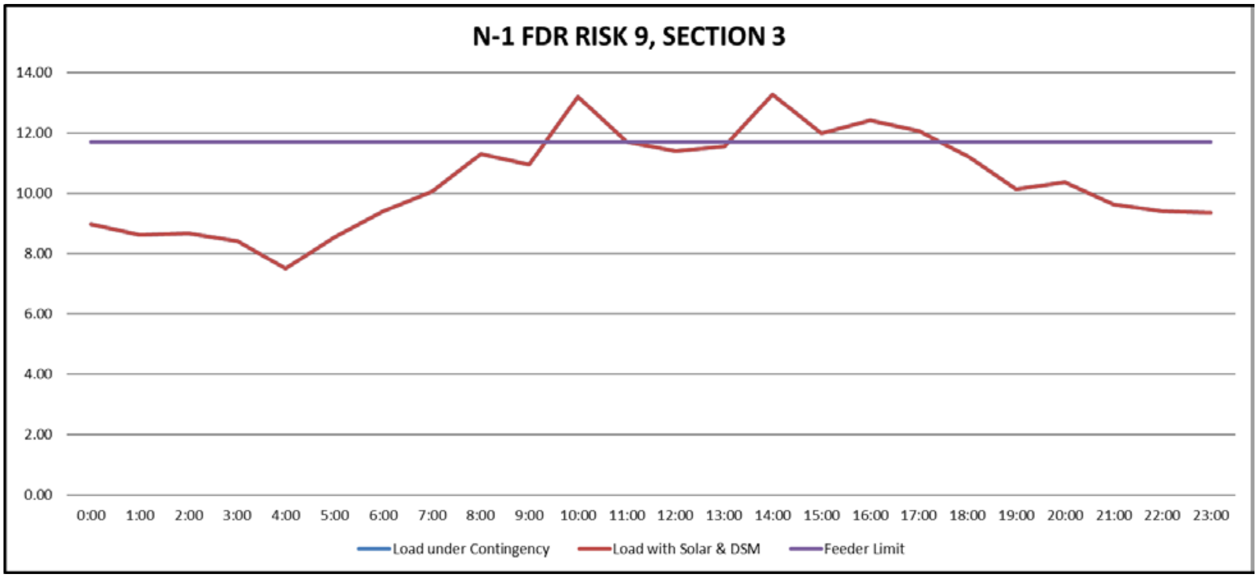
Load under Contingency
Load with Solar & DSM
Feeder Limit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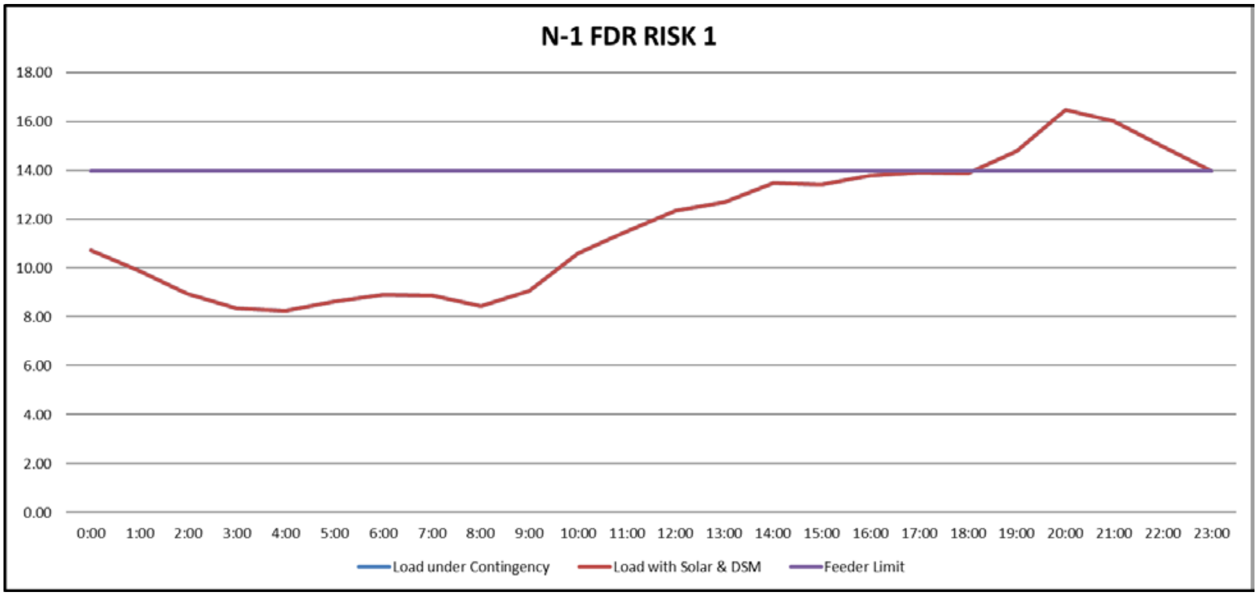
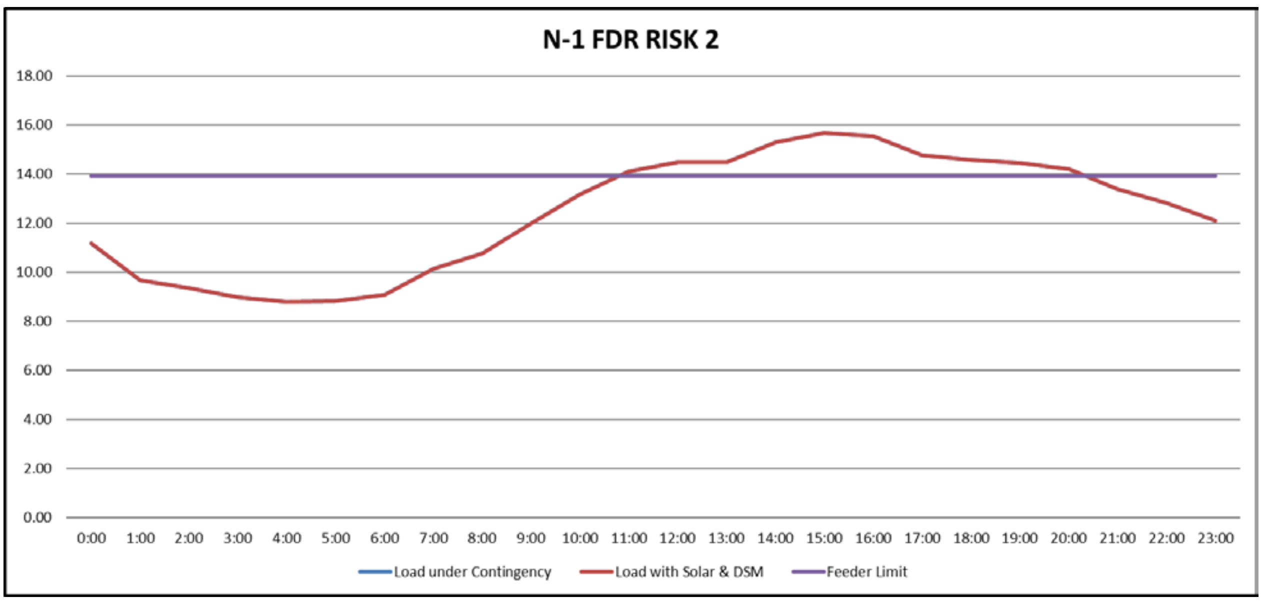
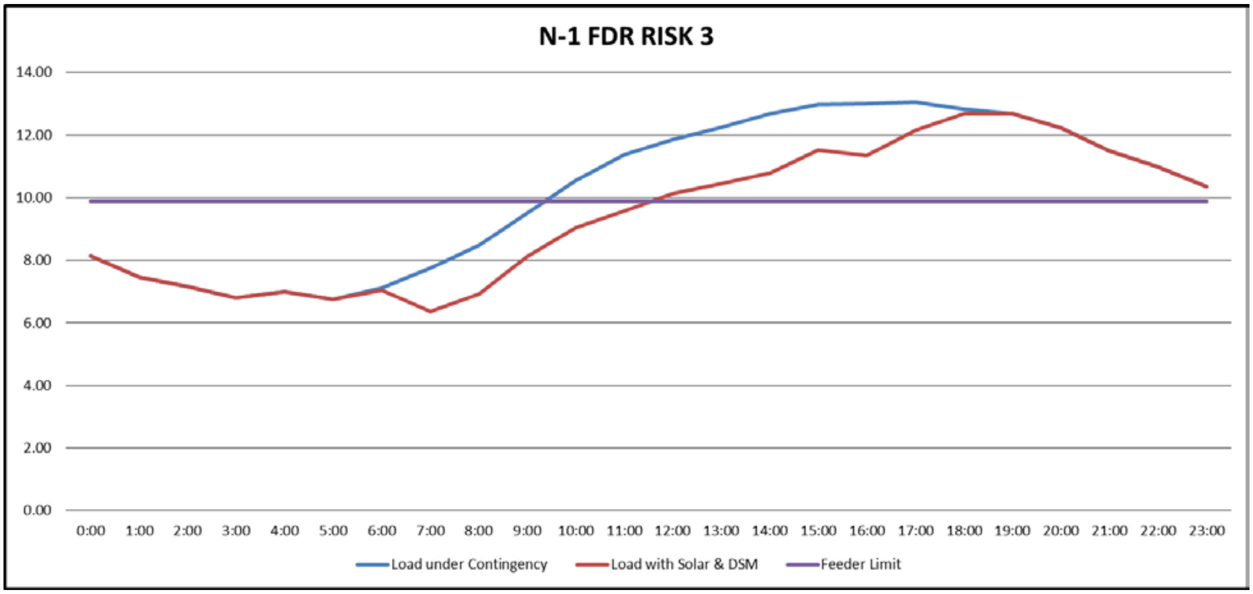
Load under Contingency
Load with Solar & DSM
Feeder Limit

M. Reinforce Faribault FAB TR1



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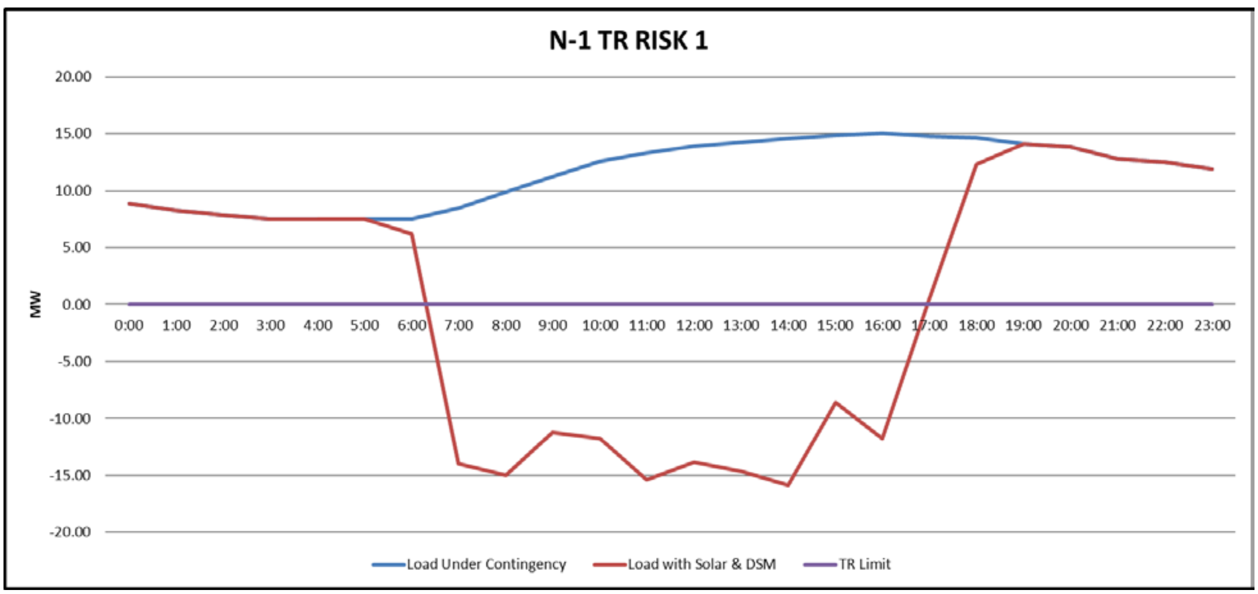
Load under Contingency
Load with Solar & DSM
Feeder Limit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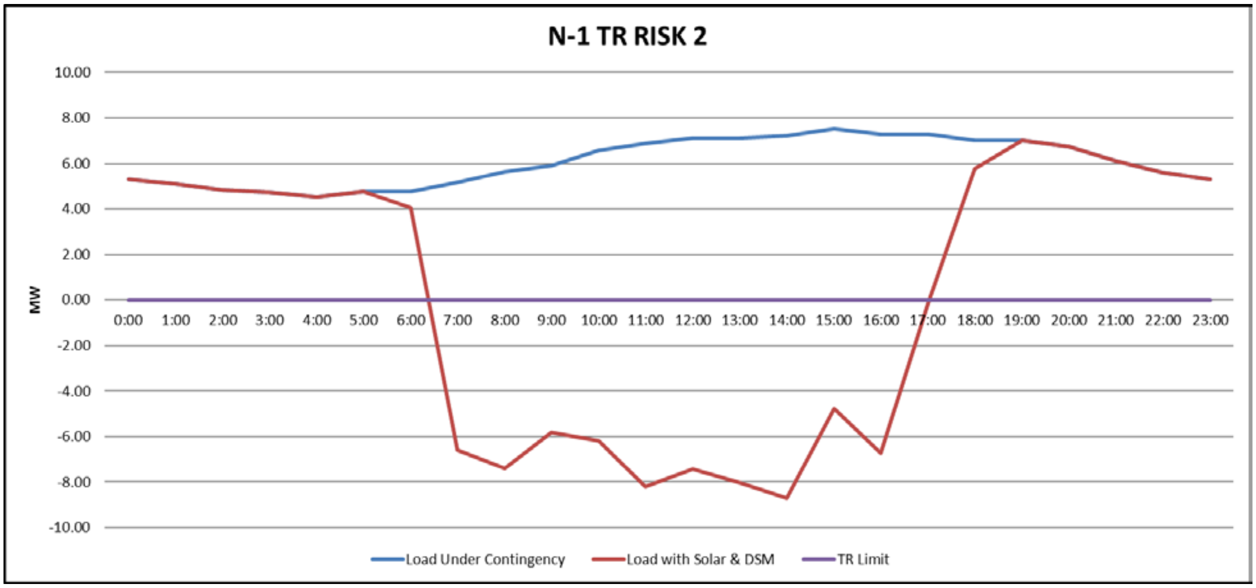
Load Under Contingency
Load with Solar & DSM
TR Limit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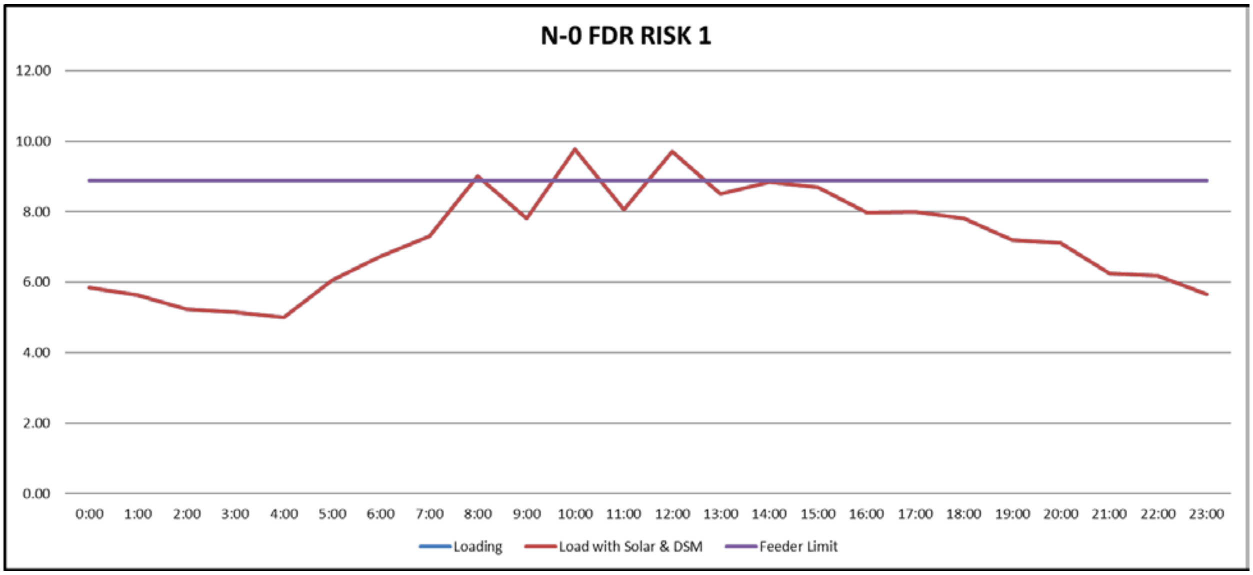
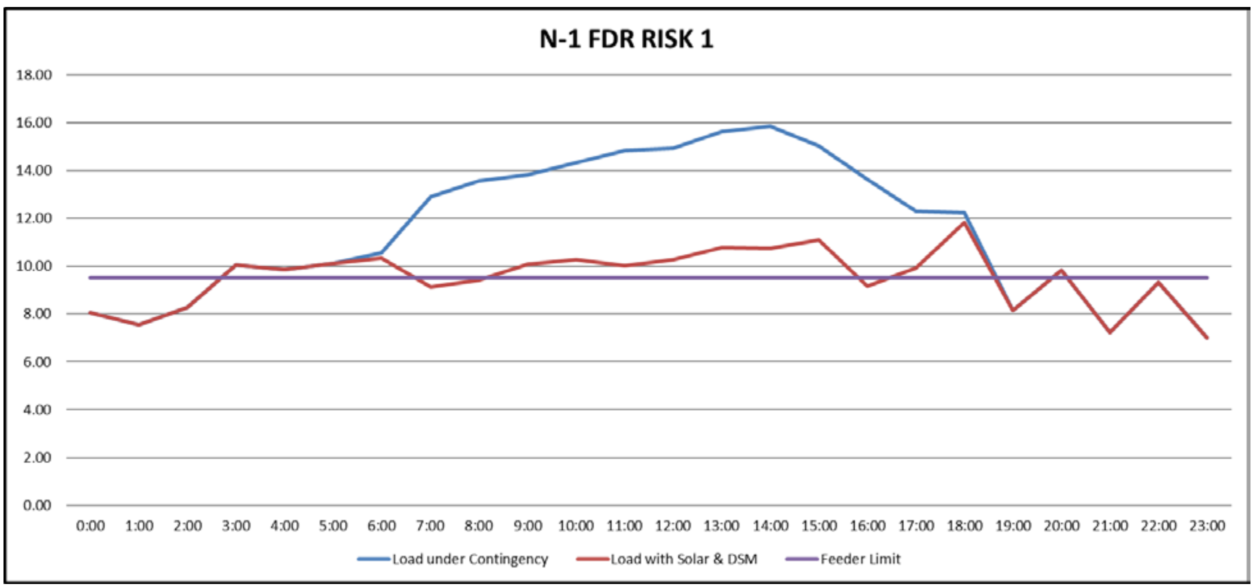
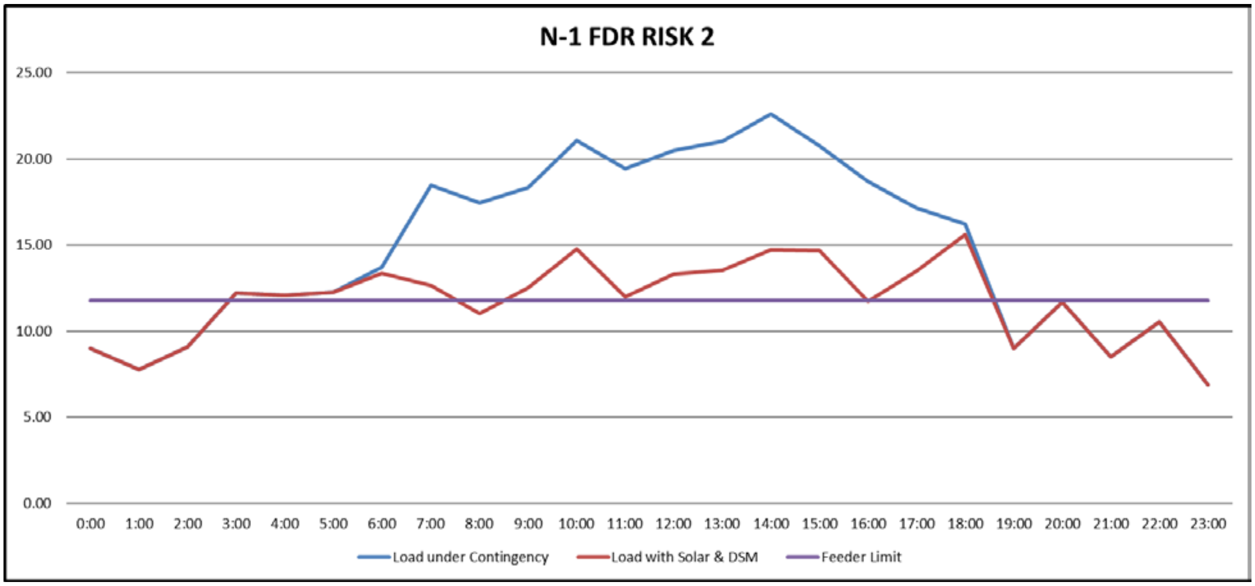
Load Under Contingency
Load with Solar & DSM
TR Limit

N. Install East Winona EWI TR2



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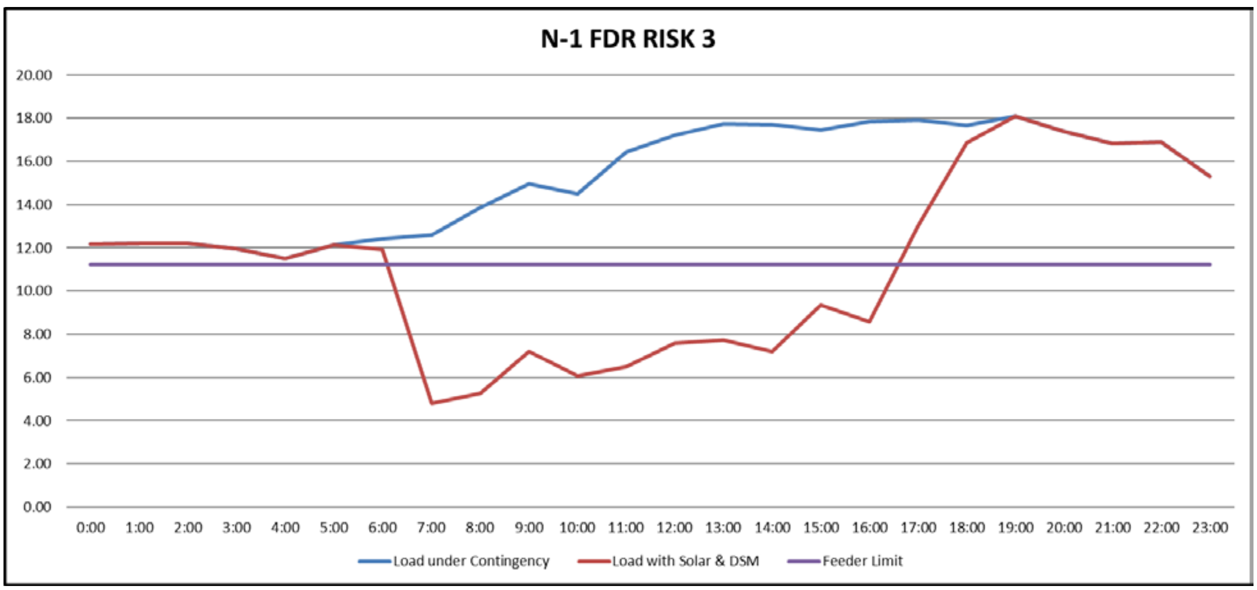
Load under Contingency
Load with Solar & DSM
Feeder Limit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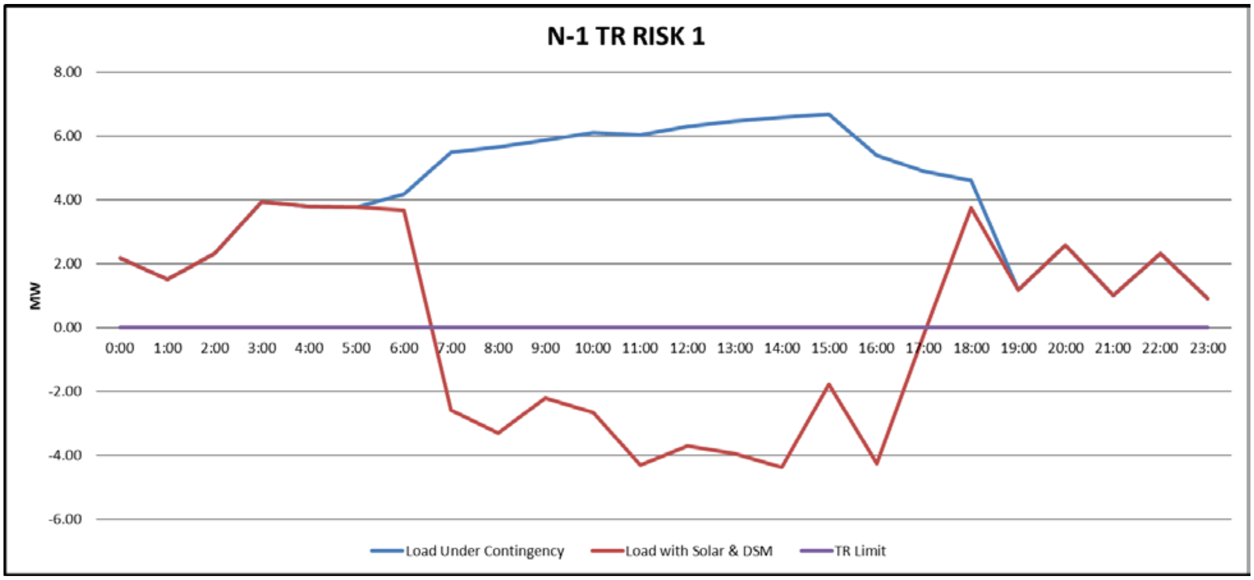
Load under Contingency
Load with Solar & DSM
Feeder Limit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2.00
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-4.00
-6.00
MW
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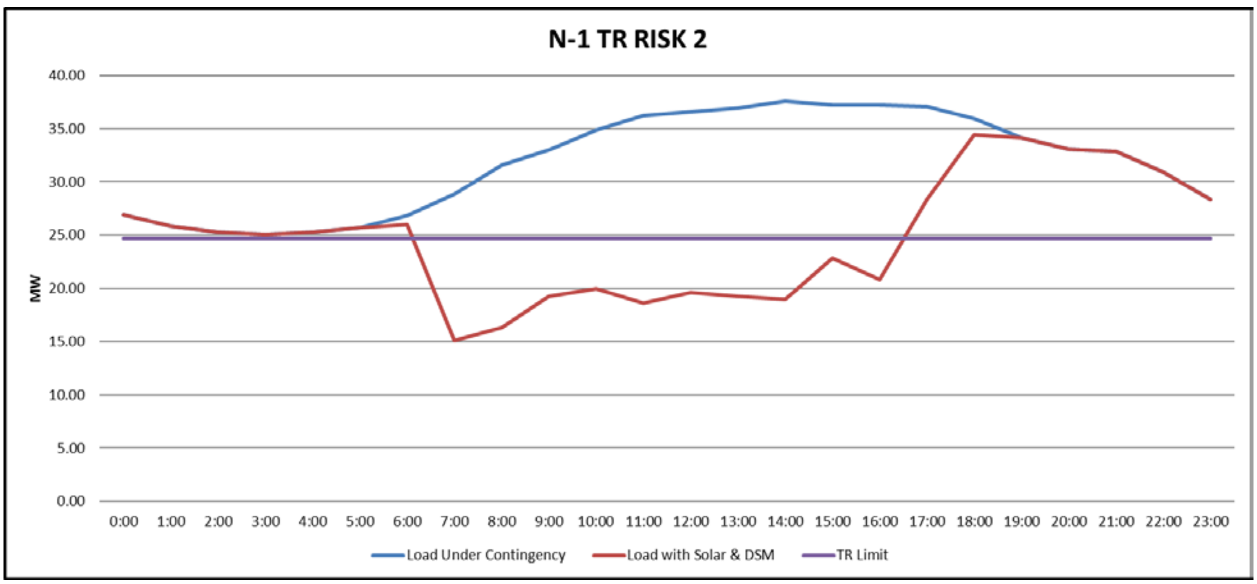
Load Under Contingency
Load with Solar & DSM
TR Limit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MW
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Load Under Contingency
Load with Solar & DSM
TR Limit

Firm Capability Statement

1200 Plymouth Avenue
Minneapolis, MN 55411
www.renewablenrgpartners.com

EXECUTIVE SUMMARY

Renewable Energy Partners is a state and local-certified Minority Business Enterprise (MBE) based in Minneapolis. Formed in 2014, REP has demonstrated its ability to deploy a quality, diverse and motivated workforce to solar job sites and get projects to commercial operation on-time and within project budgets. REP's goals are:

- Develop solar energy and other energy projects with community benefits
- Provide electrical and construction labor for Minnesota's solar energy market
- Training and jobs for BIPOC workers in utility and energy-related careers

Workforce Training and Project Construction Approach

Through its wholly-owned subsidiary, Northgate Development, LLC, REP developed the Regional Apprenticeship Training Center (RATC) in North Minneapolis. RATC was created to offer accessible skills training in advanced energy technologies and STEM-related fields for under-served residents. The training site itself includes scaled demonstrations of solar PV-plus-storage, ground-source heat pumps and electrification, energy control systems, electric vehicle charging, and comprehensive on-site stormwater management.

Since October 2020, the training center has hosted NABCEP-certified training by Midwest Renewable Energy Association (MREA) for certification as a Solar Associate. Skills training is expanding in 2021 to include electric vehicle infrastructure installation, air sealing and weatherization, and home energy auditor certification. REP works with well-established training organizations: Avivo, Inc., Project for Pride in Living, Center for Energy and the Environment, Minnesota STEM Partnership, University of Minnesota and other higher ed institutions.

On solar projects, REP has a partnership agreement with Go Solar, LLC, a certified MBE electrical contractor, and works with other MBE electrical contracting firms, and contracted professional services firms Twin Cities to provide comprehensive and scale-able EPC services for solar energy projects from 40 kilowatts to multiple megawatts. EPC crews operate under a

Master Electrician and 2-4-2 crew model with two licensed personnel, four apprentices including trainees from REP's training center, and two material handlers. With lead times of 90-120 days, multiple crews can be ready and able to provide 13,000-14,000 annual labor hours per crew.

Core Capabilities

- Engineering and electrical design
- Structural engineering and geo-technical analysis
- Permitting: state electrical, building, land use
- Equipment procurement
- Balance of System procurement
- Construction and assembly
- Interconnection and AC work
- Commissioning and testing
- Operations and maintenance

Federal Certification: SAM federal grants registration

State and Local Certification: State of Minnesota Master Electrician #EA-779870, City of St. Paul Certification (also recognized by Ramsey and Hennepin Counties), State of Minnesota SWIFT vendor, City of Minneapolis SUBP registration

Non-Government: North Central Minority Supplier Development Council (NCMSDC), North American Board of Certified Energy Practitioners (NABCEP)

Contract Vehicles: Installation Agreement with Performance Bonding and Labor Warranty, Subcontractor Agreement, O & M Service Contract

Major Clients:

- Aurora-St. Anthony Neighborhood Development Corporation
- Sand Companies
- Minneapolis Public Schools
- City of Minneapolis
- US Bank
- EMERGE
- Holy Trinity Lutheran Church

NAICS: 22114 (solar electric power), 237130 (power related construction), 238210 (electrical contractors/wiring, 811118 (electrical repair/maintenance), 541690 (energy consulting services).

General Information:
Renewable Energy Partners, Inc.
Year Incorporated: 2014
State of Incorporation: Minnesota
Corporation Type: Chapter C
DUNS #: 079524537

Contact Information: Jamez Staples, President and CEO
612-282-2573 jstaples@renewablenrgpartners.com
www.renewablenrgpartners.com

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

The Distributed Intelligence CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use.

Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:
1. Nature of the Material: The Cost Benefit Analysis Model developed by the Company.
2. Authors: Risk Analytics
3. Importance: The Company work product is proprietary to the Company.
4. Date the Information was Prepared: The CBA Model was created in the third quarter of 2021.

The Resilient Minneapolis Project CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use.

Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. Nature of the Material: The Cost Benefit Analysis Model developed by the Company.
2. Authors: Risk Analytics
3. Importance: The Company work product is proprietary to the Company.
4. Date the Information was Prepared: The CBA Model was created in the third quarter of 2021.

CERTIFICATE OF SERVICE

I, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket Nos. E002/M-21-694
E002/M-21-630
E002/M-19-666
Xcel Energy's Miscellaneous Electric Service List

Dated this 1st day of November 2021

/s/
____
Mustafa Adam
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Mary Beth	Peranteau	mperanteau@wheelerlaw.com	Wheeler Van Sickle & Anderson SC	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	SPL_SL_19-666_M-19-666

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	SPL_SL_19-666_M-19-666
Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute	1000 Vermont Ave, Third Floor Washington, DC 20005	Electronic Service	No	SPL_SL_19-666_M-19-666
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	SPL_SL_19-666_M-19-666
Gregory	Randa	granda@lakecountrypower.com	Lake Country Power	26039 Bear Ridge Drive Cohasset, MN 55721	Electronic Service	No	SPL_SL_19-666_M-19-666
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	SPL_SL_19-666_M-19-666
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	SPL_SL_19-666_M-19-666
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	SPL_SL_19-666_M-19-666
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	SPL_SL_19-666_M-19-666
Isabel	Ricker	ricker@fresh-energy.org	Fresh Energy	408 Saint Peter Street Suite 220 Saint Paul, MN 55102	Electronic Service	No	SPL_SL_19-666_M-19-666
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	SPL_SL_19-666_M-19-666

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	SPL_SL_19-666_M-19-666
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	SPL_SL_19-666_M-19-666
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	SPL_SL_19-666_M-19-666
Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	SPL_SL_19-666_M-19-666
Dean	Sedgwick	Sedgwick@Itascapower.com	Itasca Power Company	PO Box 455 Spring Lake, MN 56680	Electronic Service	No	SPL_SL_19-666_M-19-666
Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology	120 Tredegar Street Richmond, Virginia 23219	Electronic Service	No	SPL_SL_19-666_M-19-666
Patricia F	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.	180 N LaSalle St Ste 3700 Chicago, IL 60601	Electronic Service	No	SPL_SL_19-666_M-19-666
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_19-666_M-19-666
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	SPL_SL_19-666_M-19-666

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	SPL_SL_19-666_M-19-666
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	SPL_SL_19-666_M-19-666
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	SPL_SL_19-666_M-19-666
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities	208 S Walnut Ave PO BOX 800 Owatonna, MN 55060	Electronic Service	No	SPL_SL_19-666_M-19-666
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Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_19-666_M-19-666
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_GR-21-630
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_GR-21-630
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_GR-21-630
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-630_GR-21-630
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_GR-21-630
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_GR-21-630
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-630_GR-21-630
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_GR-21-630
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_GR-21-630
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_GR-21-630
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-630_GR-21-630
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_21-630_GR-21-630
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-630_GR-21-630
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_21-630_GR-21-630
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_GR-21-630
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_GR-21-630

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_21-694_M-21-694
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_21-694_M-21-694
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-694_M-21-694
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-694_M-21-694
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